Energy to the people

Aurora Energy Regulatory Proposal 2012–2017

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Foreword from the CEO

Electricity prices in Tasmania have increased significantly over the past five years. Aurora Energy recognises that investment in Tasmania's transmission and distribution networks has been a major driver of these price increases, in keeping with the State's economic growth and in order to meet more stringent reliability and safety standards.

While Tasmania's electricity prices remain competitive with other States, it is clear that the cumulative impact of successive electricity price increases has attracted an unprecedented public focus in this State. While distribution functions represent approximately 35 percent of customer electricity bills in Tasmania, Aurora Energy is committed to demonstrating industry leadership by continuing to deliver appropriate service levels while minimising future distribution-related price increases. However, it is acknowledged that Aurora Energy is unable to influence the other elements of the supply chain which may cause increases to the end price seen by customers.

The fundamental driver underpinning this *Regulatory Proposal* is the need to minimise the impact of any further price increases on Tasmanian households and businesses, while continuing to provide a safe and reliable electricity supply.

Aurora Energy's purpose "to see the Tasmanian community prosper from its efforts" is key to everything we do as a company. Our strategic focus "to meet customer needs at the lowest sustainable cost" has framed our input to this *Regulatory Proposal*.

A focus on price as the primary driver of future investment decisions is a customer focussed approach to developing a *Regulatory Proposal* for a distribution business. This focus does not negate our commitment to ensuring the provision of a safe and reliable supply of electricity. However, it does mean that Aurora will need to find innovative and sustainable ways to deliver electricity while meeting the supply standards expected by the Tasmanian community.

A critical component of Aurora Energy's distribution business strategy is ensuring that the customer is always put first in everything we do with the aim of securing the best possible price, service and reliability outcomes.

As an experienced and prudent operator of the Tasmanian electricity distribution network, Aurora Energy has a long-term strategy for the efficient delivery of services. The strategy is focused on empowering the customer through choice (a smart customer strategy) and ensuring that the delivery of electricity meets modern lifestyle requirements in a convenient and sustainable way.

The distribution business strategy is being delivered as part of a two-staged process. The approach outlined in this *Regulatory Proposal* represents the first phase of the process. During this initial stage, we are focussed on driving cost reductions from current service delivery methods, together with the selective deployment of a number of proven technologies. This will ensure our operating and capital expenditure programs are kept to the absolute minimum in order to keep customer price increases to the lowest achievable level while ensuring the provision of a safe and reliable supply of electricity. The approach taken in this *Regulatory Proposal* is therefore consistent, in the main, with the traditional engineering approach to asset management that we have successfully utilised during the current *Regulatory Control Period*.

The critical second phase of Aurora's strategy will focus on driving efficiency by changing the way services are delivered. This involves the deployment of innovative and modern technology to deliver efficient and sustainable customer outcomes in the future. However, the development of what is a relatively different approach to asset management for Aurora is in its early stages and Aurora does not consider that it has the information yet to undertake the comprehensive and robust justification required under the *Rules* for a *Regulatory Proposal*. During the period covered by this *Regulatory Proposal* Aurora will implement programs which have a clear business case and assist with its strategy in smarter and more efficient ways. We will develop the data and investment models required to fully justify this approach as the basis for the 2012-17 *Regulatory Control Period*. A smarter and more efficient network will deliver sustainable and efficient outcomes and solutions for our customers, further improving the efficiency of Aurora's capital and operating expenditure. This will position Aurora to fully deliver on its strategy during the 2012-17 *Regulatory Control Period*.

It is considered that this *Regulatory Proposal*, together with the supporting documents included, provides the necessary rigour and robust justification of Aurora's strategy and proposed approach to asset management for the forthcoming *Regulatory Control Period*. We look forward to engaging with the AER as part of the next stage of this important process.

Peter Davis, CEO

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1. Executive summary

1. Executive summary

1.1. Background

Aurora Energy Pty Ltd is a Tasmanian Government owned fully integrated energy and network business, with complementary activities in telecommunications and energy related technologies. It was formed in July 1998 after the disaggregation of the former Hydro Electric Commission.

Consistent with its purpose "to see the Tasmanian community prosper from its efforts", Aurora has made a significant contribution to the Tasmanian economy since its establishment. This has been provided through financial contributions to the Tasmanian Government to fund core Government services, its investment in the Tasmanian community in terms of employment, historic levels of capital expenditure, customer connections and its extensive support of Tasmanian suppliers.

Aurora's distribution business provides a 24-hour, seven day a week service to approximately 229,400 residential and 50,400 commercial distribution customers across the State, to ensure a safe and reliable electricity supply. Aurora's core distribution assets comprise 15,069 km of overhead high voltage lines, 7,197 km of overhead low voltage lines and 2,178 km of high and low voltage underground cables, 31,287 ground and pole mounted substations and 222,000 poles across an area of 67,800 square kilometres. Aurora also operates approximately 49,000 public lights and maintains them on behalf of local councils. The company also constructs, maintains and operates the electricity distribution network on King and Flinders Island on behalf of the Hydro Electric Corporation.

As the monopoly provider of electricity distribution services within the Tasmanian jurisdiction, Aurora's distribution business is required to hold a distribution licence in accordance with the *Electricity Supply Industry Act 1995*. As a monopoly electricity distribution business, Aurora is also subject to economic regulation of its distribution services. To date, this has been undertaken by the jurisdictional regulator, the Office of the Tasmanian Economic Regulator (OTTER). However, the current determination will conclude on 30 June 2012 and economic regulation of distribution services will transfer to the Australian Energy Regulator (AER). Aurora is therefore required to submit this *Regulatory Proposal* to the AER for its distribution services covering the five-year *Regulatory Control Period* from 1 July 2012 to 30 June 2017.

The 2007 Pricing Investigation conducted by OTTER saw significant increases in both capital and operating expenditure to ensure that the performance of Tasmania's electricity infrastructure matched the requirements of its customers and key stakeholders. This was largely driven by the need to ensure the performance of the electricity infrastructure was in keeping with the State's economic growth and was able to meet more stringent reliability and safety standards.

Aurora has realised a large part of its allowed expenditure during the current *Regulatory Control Period* and considers that investment in the distribution network is now at an appropriate level so that consolidation can occur. This outcome has been delivered while ensuring that Aurora is operating at an efficient level relative to other distribution companies in Australia.

This has been coupled with significant changes to the external drivers that impact Aurora, including:

- a slowing in the Tasmanian economy in the early years of the *Regulatory Control Period* from the above trend economic growth experienced at the time of the last Distribution Determination;
- a shift in customers' acceptance of the level of electricity price increases, given the cumulative impact of these increases;
- emerging technological advancements coupled with a change in customers' expectations for improved service and greater choice together with increased participation in managing energy costs and needs;
- potential opportunities provided to leverage off the rollout of the National Broadband Network in Tasmania in the deployment of smart grid technologies and efficiency gains through smarter metering infrastructure; and
- the establishment of an Expert Panel to undertake an independent assessment of the Tasmanian electricity supply industry.

1.2. Approach to the Regulatory Proposal

Taking these issues into account and, in particular, the need to address community concerns and expectations, Aurora's distribution business completed a major review of its business strategy in mid 2010. In developing this strategy, the distribution business has strengthened its focus on ensuring that the customer is always put first in everything Aurora does, with the aim of improving price outcomes and service and reliability outcomes which are at levels that are commensurate with both the *Rule* requirements and customers' propensity to pay. This can be achieved while at the same time ensuring that capital and operating expenditure are maintained at existing or reduced levels relative to the latter years of the current *Regulatory Control Period*.

This strategy will be delivered as part of a two-staged process. The first stage of this process involves traditional engineering solutions together with expenditure reductions that are delivered by means of operational efficiencies and the selective deployment of a number of proven technologies. Aurora has deliberately targeted a reduction in costs to assist in minimising price rises to its customers. This involves a challenging regime of productivity improvements and cost cutting across the business. To deliver these operational efficiencies, Aurora has applied an annual three percent efficiency factor to the labour rates within the unit rates included as part of this *Regulatory Proposal*. This efficiency factor results in a real reduction within the labour rates in excess of 10 percent over the duration of the *Regulatory Control Period*. The downsizing of staff, coupled with improvements in Aurora's contract management processes, and the optimisation and streamlining of all other processes, is already progressing. A continuation of this work will be critical to achieving the ambitious reductions in capital and operating expenditure proposed during the forthcoming *Regulatory Control Period*.

This approach also reflects the view that the continued sole use of traditional network augmentation to deal with short-term duration peaks is an expensive and sub-optimal strategy. Non-network approaches, such as demand-side management and distributed generation options, integrated as part of Aurora's overall planning process, offer a more cost effective strategy than continuing to allocate scarce capital to serve short-term duration peak loads.

This stage forms the basis of this *Regulatory Proposal*.

The second stage of the distribution business' strategy involves the deployment of further innovation and new technology to deliver efficient and sustainable outcomes in the future. However, the development of what is a relatively different approach to asset management for Aurora is in its early stages and Aurora is not currently in a position to provide the comprehensive and robust justification required for this *Regulatory Proposal*. Aurora's *Regulatory Proposal* does not therefore address this component of the distribution business strategy at a detailed level.

It is Aurora's intention to implement appropriate mechanisms, on the basis of robust analysis and targeted trials, to deliver the desired outcomes anticipated in this *Regulatory Proposal*, in smarter and more efficient ways during the forthcoming *Regulatory Control Period*.

A key part of the Aurora distribution business' revised approach is reconsidering how the business responds to, and addresses, risk. This *Regulatory Proposal* details the risk management framework utilised by Aurora to ensure it is managing its risks effectively, including responses to disaster management, bushfire preparedness, contingency planning and system security levels. It is Aurora's view that a smarter and more efficient network will deliver sustainable and efficient customer outcomes and solutions, together further improving the efficiency of Aurora's capital and operating expenditure, while applying appropriate risk mitigation.

1.3. Key assumptions

The capital and operating expenditure forecasts detailed in this *Regulatory Proposal* are based on the range of assumptions detailed in this *Regulatory Proposal*. These assumptions are based on all available information at the time of preparing the *Regulatory Proposal*. A range of global assumptions at the broadest level include consistency with Aurora's high-level strategy, no change to Aurora's existing structure and no material amendments to the legislative and regulatory framework (with the exception of the introduction of the National Energy Customer Framework from 1 July 2012) during the *Regulatory Control Period*.

Additional high-level assumptions presume that:

- the required works and programs for the current *Regulatory Control Period* have been delivered;

and that during the 2012-17 *Regulatory Control Period*:

- Aurora's planning standards will continue to apply in their current form;
- historical expenditure and volumes are a valid basis to build forecasts for future expenditures and volumes, that are also adjusted for forecast growth;
- capital expenditure forecasts can be estimated based predominantly on asset age data;
- Aurora has the resource availability and capability to deliver the forecast programs; and
- traditional network solutions will be applied to capital works, although during the *Regulatory Control Period* Aurora will move to implement more innovative technology where it can be demonstrated to be technically and financially prudent.

More detailed assumptions, which are central to Aurora's capital and operating expenditure forecasts, as well as assumptions specific to particular RIN categories, are detailed in this *Regulatory Proposal*. These assumptions have generally been based on advice from reputable consultants who are well regarded by industry and the AER. All advice has taken into account relevant, up-to-date market and industry information.

1.4. Capital and operating expenditure

As noted earlier, the 2007 Pricing Investigation conducted by OTTER saw significant increases in both capital and operating expenditure to ensure that the performance of Tasmania's electricity infrastructure matched the requirements of its customers and key stakeholders. This was largely driven by the need to ensure the performance of the electricity infrastructure was in keeping with the State's economic growth and was able to meet more stringent reliability and safety standards.

In a number of areas, Aurora was also required to spend over and above the expenditure allowances provided by OTTER, as detailed in Figure 1 and Figure 2 below.

It should be noted that Figure 1 and Figure 2 do not reflect all expenditure undertaken by Aurora during the current *Regulatory Control Period*. Expenditure relating to Aurora's NEM participation and retail contestability activities has been excluded from these figures as these are not considered to be operational distribution network related activities. The Regulator has also provided an alternative mechanism specifically for the recovery of this investment.

The additional expenditure was largely driven by significant increases in customer generated work driven by the buoyant economic conditions at the time. Customer generated work of approximately $200 million during the current *Regulatory Control Period* has therefore been reflected separately in Figure 1.

A peak in growth occurred during 2008-09, prior to the global financial crisis (GFC), and fell during the 2009-10 and 2010-11 years. While growth had declined during this period, capital expenditures continued to rise as Aurora completed projects instigated during the period immediately prior to the GFC. It is expected that growth will recover during the 2011-12 financial year and increase at subdued levels of less than 1 percent over the foreseeable future.

A number of major supply upgrades also contributed to this trend, including the construction of a new zone substation at Cambridge, near the Hobart airport, to support significant industrial development and the zone substation at Zeehan, on the West Coast of Tasmania, to support the mining industry.

The deployment of the broken neutral detector device to all Tasmanian households in 2008-09 was not foreseen at the time of the 2007 Determination and therefore contributed to expenditure in excess of the regulated allowance.

The need to implement a number of targeted reliability programs at a more accelerated pace than originally proposed contributed to the increased expenditure in the earlier years of the current *Regulatory Control Period*. It is expected that by the end of the current *Regulatory Control Period*, 44 individual community improvement projects will have been completed.

Storm related events throughout 2009 and 2010 were a major contributor to a significant overspend in fault and emergency response levels and associated GSL payments, which is reflected in the increased levels of operating expenditure during those years, as detailed in Figure 2.

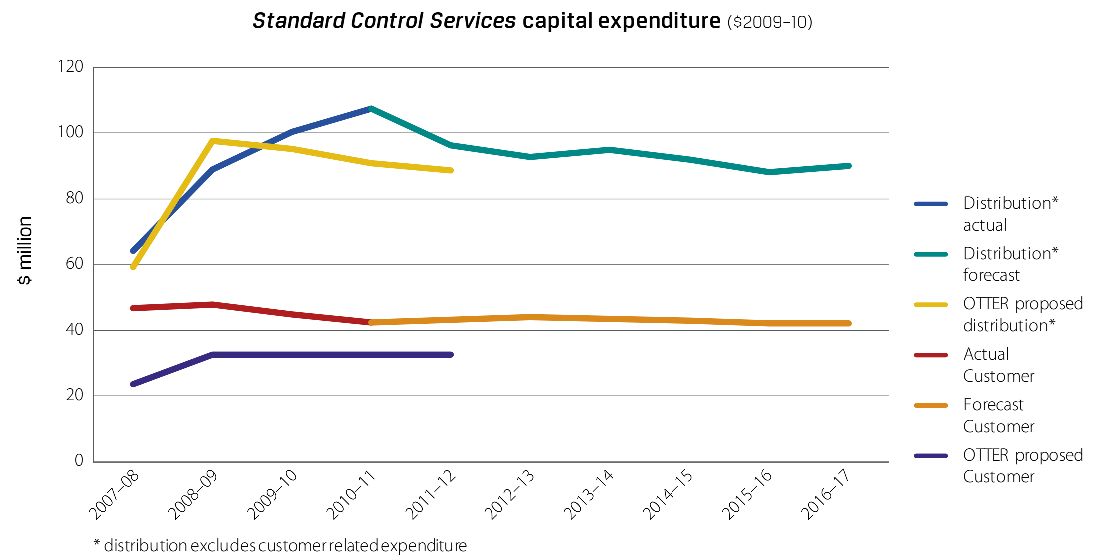
However, this additional expenditure has resulted in a strong and resilient distribution network, delivering a level of reliability and system security commensurate with the needs of the Tasmanian community. This has placed Aurora in a position where it is considered that consolidation can now occur.

Aurora's forecast capital expenditure for *Standard Control Services* for the *Regulatory Control Period* is shown in Figure 1.

1 Costs associated with Aurora's participation in the NEM and the phased introduction of retail contestability are expected to be recovered through the OTTER approved adjustment mechanisms. They have therefore been excluded from this figure.

Figure 1[1]

Forecast Standard Control Services capital expenditure



Aurora's forecast capital expenditure for *Standard Control Services*, by RIN category, for the *Regulatory Control Period* is detailed in Table 1.

Table 1

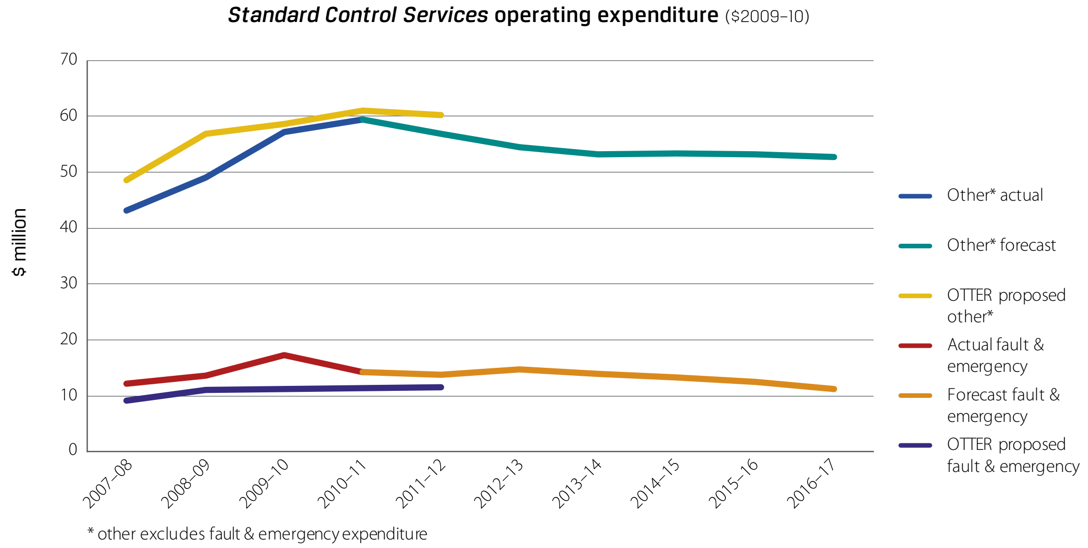
Forecast Standard Control Services capital expenditure

Aurora's Standard Control Services capital expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Capitalised overheads					
Capitalised overheads	20.506	20.606	19.850	19.383	19.565
System					
Demand related	54.855	53.842	52.466	54.062	53.542
Non-demand related	37.136	38.092	38.338	35.792	37.919
Regulatory obligations or requirements	5.515	5.484	5.230	5.152	5.043
Non system					
Non-network	17.737	14.712	13.303	15.164	15.155
SCADA and network control	1.157	5.762	5.766	0.715	0.707
Total expenditure	**136.906**	**138.498**	**134.683**	**130.268**	**131.931**

Aurora's forecast operating expenditure for *Standard Control Services* for the *Regulatory Control Period* is shown in Figure 2.

Figure 2[2]

Forecast Standard Control Services operating expenditure



2 Costs associated with Aurora's participation in the NEM and the phased introduction of retail contestability are expected to be recovered through the OTTER approved adjustment mechanisms. They have therefore been excluded from this figure.

Aurora's forecast operating expenditure for *Standard Control Services*, by category RIN, for the *Regulatory Control Period* is detailed in Table 2.

Table 2

Forecast Standard Control Services operating expenditure

Aurora's total operating expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Operating costs					
Network management	15.661	15.511	15.737	15.904	16.016
Non-network management	11.489	11.400	11.381	11.280	11.250
Operating costs – other	4.531	4.559	4.586	4.612	4.639
Maintenance costs					
Routine maintenance	16.262	16.261	16.034	15.726	15.211
Non-routine maintenance	21.439	20.501	19.860	19.030	17.547
Demand management					
Demand management	0.891	0.411	0.501	0.746	0.786
Total	**70.637**	**68.643**	**68.099**	**67.298**	**65.449**

It is considered that the forecast capital and operating expenditure established in this *Regulatory Proposal* meets the relevant objectives detailed in the *Rules* by demonstrating that the:

- identified scope is consistent with Aurora's regulatory obligations and with standard industry practice;
- demand and cost inputs have either been forecast or reviewed by independent expert third parties and determined to be realistic;
- scoping processes are reasonable and utilise realistic demand inputs, resulting in a prudent expenditure forecast that has been reviewed and assessed by independent expert third parties where possible;
- costing processes are reasonable and incorporate realistic cost inputs resulting in an efficient expenditure forecast; and
- identified scope can be delivered by Aurora.

Where expenditure differs significantly from that of the current *Regulatory Control Period*, variations are detailed in this *Regulatory Proposal*.

A range of appropriate escalation rates have been assumed in this *Regulatory Proposal* to apply to forecast capital and operating expenditure costs over the 2012 -2017 *Regulatory Control Period*. It is considered that these are consistent with the AER's approach taken in recent Distribution Determinations.

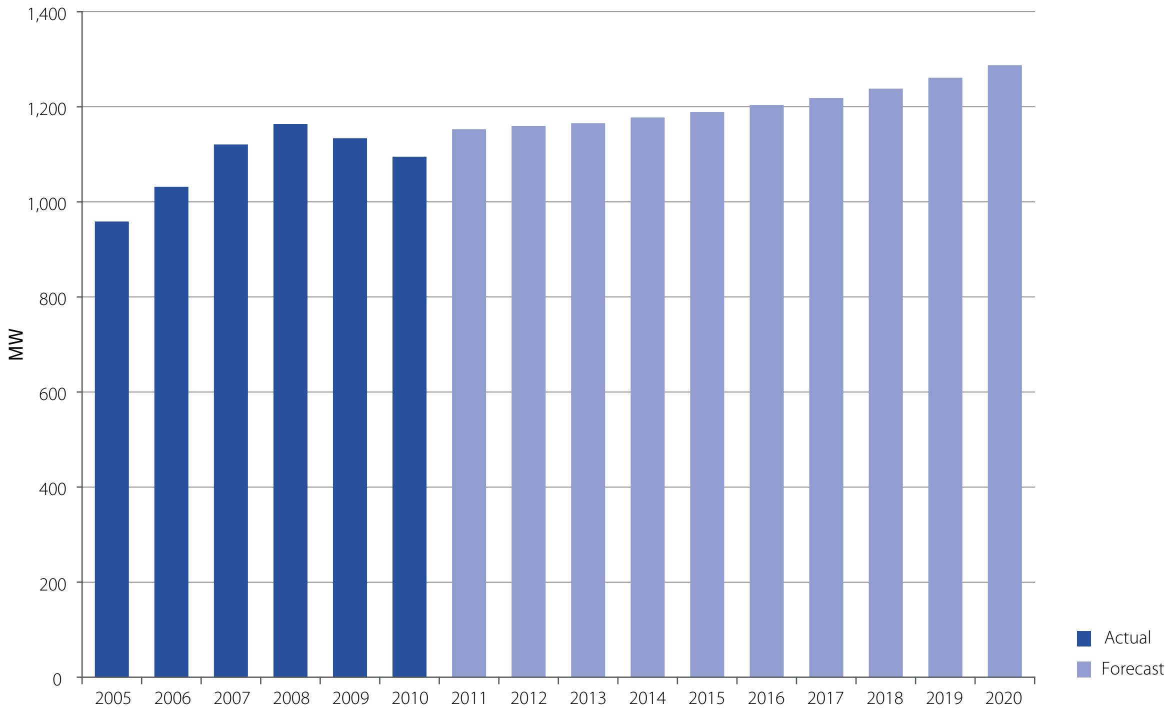
1.5. Demand profile

Peak demand on Aurora's network has historically occurred in the winter quarter with a strong correlation to the maximum daily temperature at the time of peak demand. That is, in Tasmania, demand increases as temperature decreases. The underlying drivers of peak demand on the distribution network drive the need for network infrastructure investment.

Aurora's forecast demand is presented in Figure 3. In this chart, the historic demand has been temperature corrected using the temperature sensitivity coefficient for each connection point to adjust to the long-run average temperature. The forecasts are based on a medium economic growth scenario and have been standardised to a 50 percent probability of exceedence level. These forecasts are below the long-term trend, representing the expected continued slowing in the Tasmanian economy over the early years of the forthcoming *Regulatory Control Period*.

Figure 3

Temperature corrected system coincident maximum demand



As noted earlier, options to ensure that traditional network augmentation is not solely being utilised to serve a system peak demand that occurs for less than 1 percent of the time, are considered an integral part of Aurora's strategy and are addressed as part of this *Regulatory Proposal*.

1.6. Work program delivery

Aurora is committed to meeting the reliability and investment requirements of its electricity distribution infrastructure in an efficient and effective manner. This will be achieved through a combination of:

- a review and realignment of the distribution engineering strategy;
- improvements in productivity through system and training improvements; and
- alternative external work options complementary to internal work programs.

Aurora will position its business in such a manner that will enable it to retain the right skills to complete its proposed work program in a way that ensures customers are provided with an efficient service. Aurora is confident that it will have an efficient level of competent and skilled resources that are commensurate with the level of work that it has proposed in this *Regulatory Proposal*.

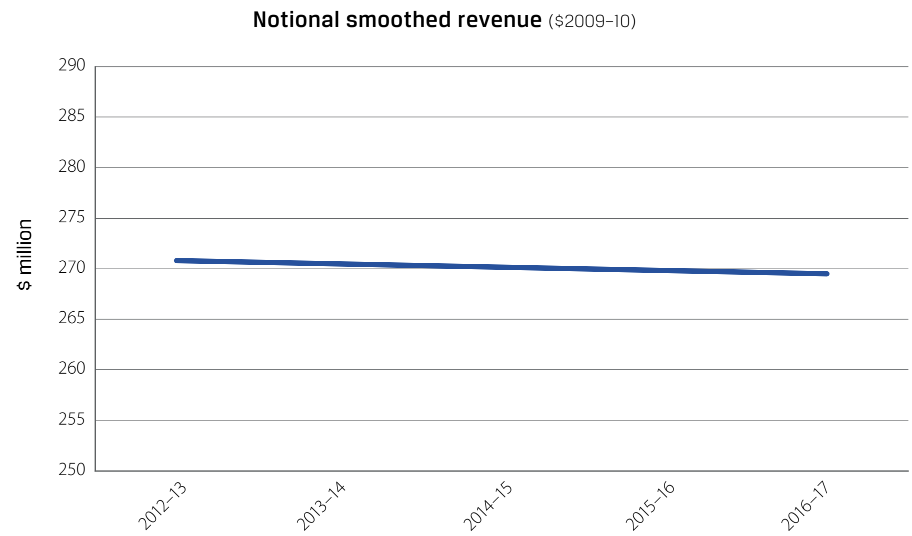
1.7. Revenue calculation

Aurora's annual revenue requirement (ARR), developed utilising the *Rules* required building block approach, comprises the sum of a number of components which are detailed in this *Regulatory Proposal*. In determining the parameter values which underpin the calculation of the regulatory cost of capital included in the building block, Aurora has accepted the parameters and methodologies detailed in the Statement of Regulatory Intent published by the AER, or as amended by the AER or determined by the Australian Competition Tribunal in relation to recent revenue Determinations.

Projected total revenue, in real 2009-10 dollars, for the *Regulatory Control Period* is detailed in Figure 4.

Figure 4

Notional smoothed revenue



The notional building block revenue requirement, in real 2009-10 dollars, for each year of the *Regulatory Control Period* is detailed in Table 3.

Table 3

Notional building block revenue

$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Notional building block revenue	266.03	273.87	272.97	268.84	269.54
Notional building block smoothed revenue	270.79	270.48	270.17	269.86	269.54

1.8. Customer pricing outcomes

Aurora's indicative prices for the provision of *Standard Control* Services have been calculated in accordance with the *Rule* requirements. In calculating these indicative prices, Aurora has adopted an approach of segregating its total revenue by the following customer classes:

- residential;
- small business – LV;
- large business – LV;
- large commercial – HV;
- irrigation; and
- unmetered supplies.

Separate consumption forecasts have been produced for each of the customer classes.

Table 4 provides an indication of distribution prices, in real 2009-10 cents per kWh, for *Standard Control Services* by customer class. These prices have been calculated using energy consumption forecasts and annual revenue requirements at the customer class level.

Table 4

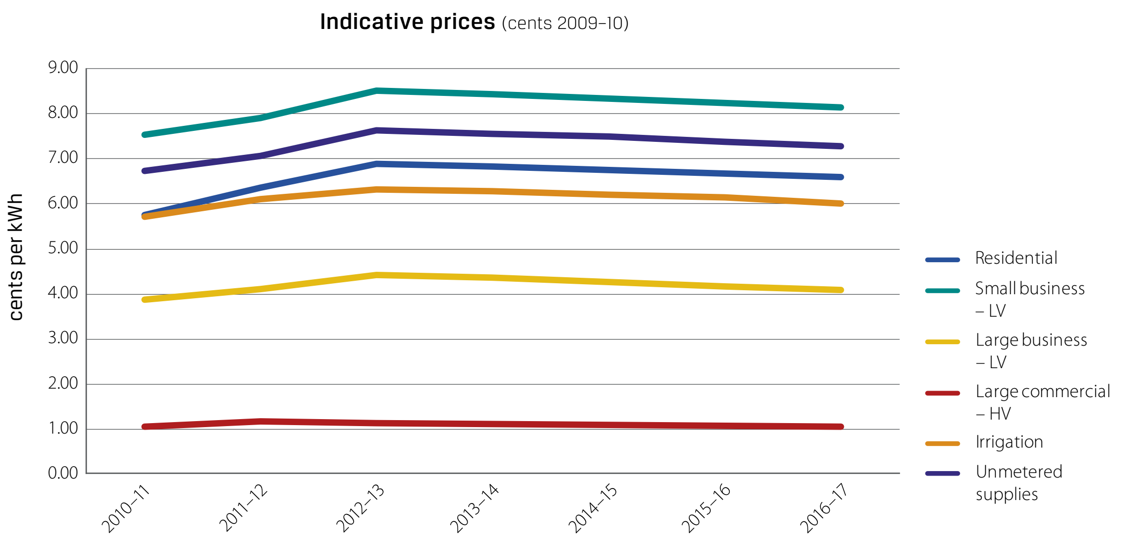
Indicative distribution prices

Cents 2009-10	2010-11 (c/kWh)	2011-12 (c/kWh)	2012-13 (c/kWh)	2013-14 (c/kWh)	2014-15 (c/kWh)	2015-16 (c/kWh)	2016-17 (c/kWh)
Residential	5.75	6.36	6.88	6.83	6.76	6.68	6.60
Small business – LV	7.53	7.90	8.51	8.44	8.33	8.23	8.13
Large business – LV	3.87	4.12	4.43	4.36	4.27	4.18	4.09
Large commercial – HV	1.05	1.18	1.13	1.12	12.10	1.08	1.07
Irrigation	5.72	6.11	6.33	6.29	6.20	6.14	6.01
Unmetered supplies	6.72	7.06	7.64	7.55	7.49	7.37	7.28
All classes	5.02	5.47	5.88	5.84	5.77	5.71	5.64
All classes (percentage change)		8.97%	7.51%	(0.70%)	(1.16%)	(1.08%)	(1.16%)

Indicative prices increase 7.5 percent between 2011-12 and 2012-13 and are largely driven in the P_o adjustment that will occur following the application of the AER's post tax revenue model that is used to derive Aurora's ARR. Following this initial price increase, indicative prices fall by an average 1.0 percent, in real terms, each year.

Figure 5

Indicative distribution prices



Indicative prices are shown in real 2009-10 cents per kWh for energy consumed, however, it should be noted that actual prices depend on specific tariffs which are made up of additional components including fixed, energy and demand charges. For this reason the above prices are considered indicative only, are not binding and are only provided for the purposes of giving a high level overview of the expected price impact for the forthcoming *Regulatory Control Period*.

In addition, Aurora's Customer Capital Contributions Policy is being revised to ensure that it provides an appropriate allocation of costs between connecting customers and users of the shared distribution network. This policy will reflect the efficient cost of providing new connection services and ensure greater equity between customer classes, consistent with the distribution business' revised strategy and the intent of the proposed National Energy Customer Framework, expected to commence from 1 July 2012.

1.9. Conclusion

Aurora is committed to demonstrating industry leadership by continuing to deliver a safe and reliable electricity supply while minimising the impact on Tasmanian households and businesses of any future distribution-related price increases. However, it is acknowledged that Aurora's distribution business is unable to influence the other elements of the supply chain which may cause increases to the final prices seen by customers. This is the fundamental driver underpinning this *Regulatory Proposal*.

This commitment will be delivered by a challenging regime of productivity improvements and cost cutting across the business, together with significant changes to the way services are delivered. This will involve a move over time to a smarter and more efficient network that will deliver sustainable and efficient outcomes for our customers, further improving the efficiency of Aurora's capital and operating expenditure.

It is considered that this *Regulatory Proposal*, together with the supporting documents included, provides the necessary rigour and robust justification of Aurora's proposed approach to asset management for the forthcoming *Regulatory Control Period*.

2. Minimising price increases for Aurora's customers

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2.1. Introduction

Consistent with Aurora's purpose "to see the Tasmanian community prosper from its efforts", the company has made a significant contribution to the Tasmanian economy since its establishment in 1998. This has been provided through its financial contributions to the Tasmanian Government to fund core Government services, its investment in the Tasmanian community in terms of employment, historic levels of capital expenditure and customer connections and its extensive support of Tasmanian suppliers.

A key driver of the significant increase in expenditure proposed as part of Aurora's 2007 submission to OTTER was to ensure that the performance of Tasmania's electricity infrastructure matched the requirements of its customers and key stakeholders, including Aurora's shareholder, the Tasmanian Government.

2.2. Impact of change

At the time of the last Distribution Determination, Tasmania had experienced an extended period of unprecedented economic growth. The economic recovery that commenced in 2001-02 was continuing to show above trend economic growth, supported by strong jobs growth, public and private sector investment close to record levels, high levels of consumer spending and growth in export sales. The unemployment rate was at a record low, one half of the level it had been a decade previously.

This trend has continued through the current *Regulatory Control Period*, despite the significant slow-down in the world and national economies in 2008 and 2009 as a result of the global financial crisis. This is consistent with past economic cycles where there has usually been a lag between changes in national economic conditions and changes in the Tasmanian economy. Tasmania also benefited proportionally more than most other jurisdictions from the Australian Government's *Nation Building – Economic Stimulus Plan*[1], as a higher proportion of Tasmanian households are on lower incomes and receive welfare payments.

During 2010, the Tasmanian economy experienced a slowdown as the stimulus was withdrawn and is emerging from the global economic downturn at a weaker pace than Australia as a whole. Private investment remains weak and is likely to remain so in the near term. Tasmanian employment is yet to recover to pre-crisis levels, unlike other jurisdictions.

The Australian Government's recent *Mid-Year Economic and Fiscal Outlook* stated that:

> *"as fiscal stimulus is withdrawn, private-sector led growth is taking hold, with business investment and commodity exports emerging as the key drivers of growth."*[2]

To date, this has not been the case in Tasmania, and the State's growth is unlikely to keep up with national growth.

Customer expectations

There have been relatively consistent increases in electricity prices over the past five years, both nationally and in Tasmania, particularly associated with significant investment in the transmission and distribution networks to meet increasing reliability and safety standards. In Tasmania, the past twelve months has seen a significant shift in customers' acceptance of the level of electricity prices given the cumulative impact of these increases.

While the rising cost of electricity has also been a national issue, it is arguable that it is proportionally more significant in Tasmania than other States and Territories. There are many reasons for this, including Tasmania's relatively lower average incomes and higher levels of welfare dependency, coupled with higher energy consumption and the inability of customers to access affordable alternative fuels such as natural gas.

1 The Hon. Mr Michael Aird MP, Treasurer for the State of Tasmania, *Budget Paper No 1, page 1.7.*

2 The Hon. Wayne Swan MP, Deputy Prime Minister and Treasurer of the Commonwealth of Australia and Senator the Hon. Penny Wong, Minister for Finance and Deregulation of the Commonwealth of Australia *Mid-Year Economic and Fiscal Outlook – Part 1: Overview – Economic Outlook,* paragraph 5.

Cumulative increases in electricity prices were a significant issue during the March 2010 State election and have continued to receive regular media coverage throughout the year.

The Government is aware of the pressures being faced by Tasmanian households and businesses and is working to find innovative and sustainable ways to help Tasmanians save money and avoid financial pressures. A range of means to achieve this is being investigated by the Tasmanian Government. This includes an independent assessment of the electricity industry in Tasmania.

Government review of the energy industry in Tasmania

In early 2010, the Tasmanian Government announced the establishment of an Expert Panel[3] to undertake an independent assessment of the Tasmanian electricity industry in accordance with the *Electricity Supply Industry Expert Panel Act 2010*. The Government considered that a key point had been reached in the ongoing energy reform process in Tasmania and that a review of the industry needed to be undertaken to assess its current status; energy mix; the assumptions that underpin it; and to provide guidance for ongoing development. As noted above, a key driver for the Government is also the need to ensure that the cost of living impact of electricity prices is kept to a minimum while also ensuring the sustainability and viability of the industry is not compromised.

The Review is due to be completed by December 2011.

Advancements in technology

At the time of Aurora's last submission to OTTER, smart technologies for managing the network were only beginning to emerge and were prohibitively expensive relative to more traditional approaches to asset management.

However, since that time, technological advancements have been coupled with a change in customers' expectations for improved service and greater choice together with increased participation in managing their energy costs and needs.

A move over time to a smarter grid will ensure an electricity distribution network in the future that is able to manage and integrate intelligently the actions of all parties (producers and/or consumers) to deliver products and services in the most efficient way. This smarter grid will employ innovative products and services, together with control, communication and distribution automation technologies, to:

- facilitate the connection and operation of producers with different dimensions and technologies;
- allow consumers to play an active role in the operation of the system;
- supply more information and more power of choice to the consumer for electricity supply;
- significantly reduce the environmental impact of the electricity system; and
- improve the reliability and the electricity supply security states.

3 The Hon. Bryan Green MP, Minister for Energy and Resources, *Electricity Supply Industry Expert Panel Bill 2010 Fact Sheet*, at page 1.

Rollout of National Broadband Network in Tasmania

The rollout of the national broadband network (NBN) in Tasmania will provide high speed fibre network connection to the vast majority of premises at its completion.

These connections will provide Aurora with a number of potential opportunities to leverage off that rollout in the deployment of smarter grid technologies and efficiency gains through smarter metering infrastructure. It allows Aurora to access NBN communication infrastructure, with potential synergies in installation.

Conclusion

While the approach taken in 2007 was valid at the time of the previous determination and in fact, has delivered significant economic benefits to Tasmania, it is clear that the drivers underlying Aurora's approach have changed markedly.

During the latter part of 2010, Aurora undertook a major review of its distribution business strategy, taking into account changes to the external environment and a proactive approach to addressing community concerns and expectations. The development of this strategy has entailed a strengthening of the focus to ensure that the customer is always put first in everything Aurora does, with the aim of ensuring improved price outcomes; and service and reliability at levels that are commensurate with both *Rule* requirements and customers' propensity to pay.

2.3. Distribution business strategy development

2.3.1. Aurora's strategic planning process

Aurora has a comprehensive strategic planning process to ensure that the business is clear about its purpose, aware of the challenges it faces and proactive in addressing these and delivering on its purpose. This process has resulted in the development of a high-level framework that has assisted in the management and communication of Aurora's strategy throughout the business.

Aurora's purpose "to see the Tasmanian community prosper from its efforts" provides the high-level overarching statement to guide Aurora's future direction. Aurora's purpose is underpinned by strategic objectives relevant to each area of the business as well as corporate objectives that relate to the whole company.

Further details about Aurora's strategic planning processes are detailed in Chapter 3, Governance arrangements.

As noted above, the past two years has been a period of significant change for Aurora, resulting in a comprehensive review of its strategy and operations. The changes have resulted in Aurora essentially being made up of four relatively diverse operational business units: an energy business; a distribution business; a telecommunications business; and EziKey, which is the company responsible for commercialising the broken neutral detector device. This review of the high-level strategy has culminated in wide-ranging reviews of the strategic direction for each of the separate operational business units.

2.3.2. Aurora distribution business – review of strategic direction

The strategy for Aurora's distribution business was subject to a comprehensive review during the latter part of 2010 in response to a number of internal and external drivers. The strategic direction was defined by:

- delivering better customer outcomes through cost efficiency;
- a focus on innovation and ensuring it has the technical capability to deal with increasing complexity and advancements in technology;
- continuing to build the important relationship between the two divisions of the distribution business, Network and Network Services, promoting the concept of "One Distribution Business"; and
- maintaining safety, reliability and sustainability as business imperatives.

An aspirational target for the distribution business has been proposed which should ensure that:

> *"The distribution business will not contribute to any price increases for customers for an agreed period."*

This is a long-term aspirational goal for the distribution business which is unlikely to be achieved during the period covered by the forthcoming *Regulatory Control Period*. However, it is an important long-term target guiding the Aurora distribution business' future direction and will contribute to delivering, in the short term, more moderate price increases than have been experienced elsewhere in Australia in recent years.

The strategic direction for the distribution business is depicted in Figure 6 below.

2.3.3. Key performance measures

An effective strategy needs to be subject to constant review and refinement as internal and external circumstances change. In order to ensure that the distribution business' strategy continues to remain relevant, a range of key performance indicators exist at the business, strategy and initiative level. These indicators will be instrumental in ensuring that the distribution business is delivering on its financial outcomes as well as providing an acceptable level of value to customers (both in terms of price and service) while not compromising network security and the safety of its employees and the public.

Figure 6

Distribution business strategy

Purpose	To be a customer-focussed, innovative, sustainable and cost-efficient business that makes a difference in the Tasmanian community.
Aspirational Goal	No increase to customer prices as a result of Aurora's efforts.
Strategies	Turn up once Do the right things One distribution business
Not Negotiables	Ensuring the overall safety of Aurora's people and customers, recruiting, training and retaining the best people and delivering on shareholder and customer outcomes.

The strategies are defined as:

Turn Up Once – Materially enhance the efficiency of Aurora's work delivery through good planning, flexibility amongst the workforce and utilising available technology and field tools.

Do the Right Things – Managing the distribution system within the constraints of expenditure and risk by improving Aurora's work prioritisation tools, increasing its technical expertise and adding customer value by focussing on innovation and technology.

One Distribution Business – Reviewing the value achieved through business processes and optimising these through the removal of duplication and alignment of direction.

2.4. Approach to the Regulatory Proposal

It is clear that the key driver underpinning the distribution business strategy and its input to this *Regulatory Proposal* is the need to minimise the impact of further price increases to customers. This can be achieved by ensuring that capital and operating expenditure over the forthcoming *Regulatory Control Period* is maintained at existing or reduced levels relative to the latter years of the current *Regulatory Control Period* , while maintaining a safe and reliable network.

Critical to this approach has been the significant investment in Aurora's distribution network over recent years. This investment has resulted in a strong and resilient distribution network, delivering a level of reliability and system security commensurate with the needs of the Tasmanian community. Aurora considers that consolidation can now occur. This outcome will be delivered while ensuring that Aurora is operating at an efficient level relative to other distribution companies in Australia. This efficiency is demonstrated by benchmarking undertaken as part of the development of this *Regulatory Proposal*. Notwithstanding this, Aurora considers that it has the capacity to continue to deliver service and reliability at appropriate levels, while also providing improved price outcomes. While this is the case, the capital and operating expenditure proposals put forward in this *Regulatory Proposal* are seen as the absolute minimum necessary at this early stage in the strategy development process. These expenditure proposals will ensure the efficient operation of the distribution system in Tasmania consistent with the National Electricity Objective, which is:

> *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> (a) *Price, quality, safety, reliability and security of supply of electricity; and*
>
> (b) *The reliability, safety and security of the national electricity system.*[4]*"*

The distribution business' strategy will be implemented as part of a two-staged process. The first stage of this process involves traditional engineering solutions together with expenditure reductions being delivered by means of operational efficiencies, together with the selective deployment of a number of proven technologies. Aurora has deliberately targeted a reduction in costs to assist in minimising price rises to its customers. This involves a challenging regime of productivity improvements and cost cutting across the business. To deliver these operational efficiencies, Aurora has applied an annual three percent efficiency factor to the labour rates within the unit rates included as part of this *Regulatory Proposal*. This efficiency factor results in a real reduction within the labour rates in excess of 10 percent over the duration of the *Regulatory Control Period*. The downsizing of staff, coupled with improvements in Aurora's contract management processes, and the optimisation and streamlining of all other processes is already progressing. A continuation of this work will be critical to achieving the ambitious reductions in capital and operating expenditure proposed during the forthcoming *Regulatory Control Period*.

The continued sole use of traditional network augmentation to deal with duration peaks is an expensive and sub-optimal strategy. Non-network approaches, such as demand side management, including water heating load control programs, and distributed generation options, integrated as part of Aurora's overall planning process offer a far more cost effective strategy than continuing to allocate scarce capital to serve short duration peak loads. As detailed later in this *Regulatory Proposal*, this approach is entirely consistent with the requirement in the *Rules* for Aurora to have considered and made provision for non-network solutions, including the requirement obligating Aurora to investigate and consult on demand side management and generation options when investigating options to address identified limitations in the distribution network.

This initial stage of the distribution business strategy forms the basis of this *Regulatory Proposal* and Aurora's expenditure proposals have been developed within a standard asset management framework with the necessary levels of rigour and justification required by the AER and the *Rules*.

The second stage of the distribution business strategy involves the deployment of further innovation and technology to deliver efficient and sustainable outcomes in the future. However, the development of what is a relatively different approach to asset management for Aurora is in its early stages and Aurora is not currently in a position to provide the comprehensive and robust justification required for this *Regulatory Proposal*. Aurora's *Regulatory Proposal* does not therefore address this component of the distribution business strategy at a detailed level.

However, it is Aurora's intention to implement appropriate mechanisms, on the basis of robust analysis and targeted trials, to deliver the desired outcomes anticipated in this *Regulatory Proposal* in smarter and more efficient ways during the forthcoming *Regulatory Control Period*. It is Aurora's view that a smarter and more efficient network will deliver sustainable and efficient customer outcomes and solutions, providing further efficiency in Aurora's capital and operating expenditure programs for the forthcoming *Regulatory Control Period*.

Aurora's approach will ensure that the impact of further price increases is limited while also providing the capacity for customers to take advantage of new and innovative technologies. This approach provides improved service and greater choice, together with increased participation by those customers in managing energy costs and needs. It is also considered that this revised approach has the greatest potential to deliver economic benefits to the State. These benefits remain consistent with the requirement of the regulatory test to identify new network investments or non-network alternative options that maximise the net economic benefit to all those who produce, consume and transport electricity in the market.

4 *National Electricity (South Australia) Act 1996*, Section 7.

2.5. Submission of the Regulatory Proposal

Aurora submits this *Regulatory Proposal* to the AER in accordance with the requirements of clause 6.8 of the National Electricity Rules (the *Rules*). This *Regulatory Proposal* is also submitted in accordance with other relevant regulatory instruments, including the AER's *Regulatory Information Notice* (RIN) [5] and the AER's final decisions on classification of services and control mechanisms and application of schemes as outlined in the *Framework and Approach* paper.[6]

This *Regulatory Proposal* applies to the *Regulatory Control Period* from 1 July 2012 to 30 June 2017 and has been prepared in accordance with relevant regulatory requirements.

Aurora submits this *Regulatory Proposal* to the AER so that it may make an electricity Distribution Determination that will apply to Aurora for the *2012-17 Regulatory Control Period*.

Aurora's *Regulatory Proposal* provides details of its proposed capital and operating programs and the required revenue for the 2012-17 *Regulatory Control Period* and is supported by a disk containing copies of additional detailed internal Aurora material to substantiate the information presented in this *Regulatory Proposal*.

5 Regulatory Information Notice, from AER to Aurora, 21 April 2011.

6 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010.

3. Background and organisational overview

3. Background and organisational overview

Aurora is a fully integrated energy and network business with complementary activities in energy-related technologies and telecommunications.

Aurora is a Tasmanian Government-owned company established under the *Electricity Companies Act 1997* and incorporated under the *Corporations Act 2001*. Aurora commenced operations on 1 July 1998 to provide services to the Tasmanian community in the areas of electricity retailing and distribution. It has two shareholders, the Minister for Energy and the Treasurer.

Over the past 13 years Aurora has expanded its activities in Tasmania to include the provision of gas retailing services to homes and businesses, and telecommunications infrastructure services to Government and large corporate customers. Aurora also owns and operates the Tamar Valley Power Station through a subsidiary company, Aurora Energy (Tamar Valley) Pty Ltd and owns dispatch rights to certain other power stations.

Aurora employs 1,432 people, including 58 apprentices, trainees and employees of subsidiary companies, making Aurora one of Tasmania's largest employers. The commercial returns Aurora provides to its shareholders are channelled into essential services for the Tasmanian community.

The company's registered head office is 21 Kirksway Place in Hobart. It operates at sites around Tasmania, with four major resource centres located at Cambridge east of Hobart, at Rocherlea in the northern suburbs of Launceston and at Devonport and Burnie on the north-west coast.

These resource centres are supported by 10 response centres in regional areas (including King and Flinders Islands). Aurora also has employees based in its energy trading office in Melbourne.

Aurora provides a 24-hour a day service to its Tasmanian customers to ensure a safe and reliable electricity supply across an area of approximately 67,800 square kilometres.

Aurora's core distribution assets comprise 15,069 km of overhead high voltage lines, 7,197 km of overhead low voltage lines and 2,178 km of high and low voltage underground cables, 31,287 ground and pole-mounted substations and approximately 222,000 poles. Aurora also operates and maintains approximately 49,000 public lights.

A number of small privately-owned generation units are connected directly to Aurora's distribution network. These include municipal gas plants at the Hobart and Glenorchy refuse disposal centres and mini hydro generators associated with irrigation schemes.

Relevant jurisdictional legislation

As noted above, the *Electricity Companies Act 1997* provides for the establishment of Aurora. It imposes a range of requirements on Aurora, particularly in relation to the company formation, the payment of guarantee fees and taxation equivalents and superannuation provisions. It also provides for application of Treasurer's Instructions[1], which provide more specific requirements particularly in relation to the payment of income tax equivalents and guarantee fees. Specific Treasurer's Instructions are available on the website for the Tasmanian Department of Treasury and Finance at www.treasury.tas.gov.au.

The *Electricity Supply Industry Act 1995* (ESI Act), among other things, requires that Aurora:

- must not carry on operations unless it holds a licence in accordance with the Act; and
- must comply with the provisions of the *Tasmanian Electricity Code*.

As the monopoly provider of distribution services within the Tasmanian jurisdiction, Aurora is required to hold a distribution licence in accordance with the ESI Act. This licence was issued in December 1998 by OTTER and authorises Aurora to distribute electricity on mainland Tasmania subject to certain conditions and regulatory controls.

1 *Electricity Companies Act (Tas) 1997*, Section 16.

Governance arrangements

In addition to its establishing legislation, Aurora's governing constitution is its Memorandum and Articles of Association, which have been determined by Aurora's shareholders. Principal Objectives for the company are detailed in the Memorandum of Association. These are:

- to operate Aurora's activities in accordance with sound commercial practice; and
- to maximise Aurora's sustainable return to its shareholders.

Aurora's primary purposes specified in its Memorandum of Association are to undertake the following activities:

- the distribution of electricity;
- the retailing of electricity;
- activities related to or associated with the distribution or retailing of electricity; and
- any other activity, which the shareholders may, by special resolution, approve.

In June 2009 the shareholders passed a special resolution approving company activities in wholesaling gas and electricity that support:

- gas and electricity retailing;
- electricity generation using the Tamar Valley Project;
- managing trading rights for the Bairnsdale Power Station; and
- contracts to sell gas to wholesale customers.

The Board is responsible for the overall corporate governance of the company. It is responsible for setting the strategic directions and objectives for the company and for monitoring the achievement of these objectives in accordance with the Board Charter.

The Board approves the Corporate Plan submitted to shareholders and approves and monitors operating budgets submitted by management. It is responsible for the approval and review of major expenditure and reviews operating performance on a regular basis.

Further information in relation to the Board's responsibilities, including the company's Corporate Governance Framework, is detailed in Aurora's 2009-10 Annual Report [2].

The CEO and Aurora Executive Team, which includes the CEO and General Managers responsible for the core operational business units and the four whole-of-business corporate and shared services divisions, are responsible for the day-to-day management of the company and act in accordance with directions from the Board.

Strategic direction

As noted above, the Board is responsible for setting the company's strategic direction consistent with the Government's expectations as set out in Aurora's constitution and associated governance documents. Aurora has a comprehensive strategic planning process to ensure that the business is clear about its purpose, aware of the challenges it faces and proactive in addressing these and delivering on its purpose. This process culminates in the preparation of a Corporate Plan for the shareholders in March each year.

The company operates in accordance with the direction set out in the Corporate Plan and its shareholders' expectations. Aurora's Statement of Corporate Intent[3], approved by the Board and management team in 2007 during the development of its 2008-11 Strategic Plan, has become the central focus for the company's whole-of-business strategy. It is to ensure that Aurora:

> *"acts in the best interests of Tasmanian consumers, consistent with the Government's energy, development and social objectives; and operates as a viable integrated business of sufficient scale to be successful in a national environment, delivering commercial returns to its shareholders."*

Further clarification has been provided as part of the 2010 strategy development process. An approved strategic focus for the business demonstrates Aurora's commitment to delivering electricity safely and reliably to meet its customers' needs at the lowest sustainable cost.

Initiatives are developed for each business aligned to the overall strategy, with key performance indicators developed to ensure that they all continue to be relevant and that they are being implemented in accordance with agreed criteria or targets. To ensure that the Board is kept informed in relation to progress with the implementation of all initiatives and to ensure ongoing external scrutiny of divisional performance, monthly Board reports reflect performance against key performance measures.

The Board and management team regularly review and refine Aurora's strategy to ensure that it remains relevant. As noted earlier, the strategy for the distribution business was subject to extensive review during the latter part of 2010 to ensure an increased focus on customer outcomes, particularly in relation to price, as well as improving the efficiency of the distribution network while maintaining safety, reliability and sustainability.

The company is also guided by the results of customer satisfaction and model corporate citizen surveys, an annual employee engagement survey and an analysis of media coverage.

In the past 12 months, feedback from a range of Aurora's stakeholders has indicated that the most significant challenges for the business are energy price and value for money; a safe, secure and reliable power supply; a safe workplace; and effective environmental management. More detailed information in relation to Aurora's stakeholder management activities is included in Aurora's 2009-10 Annual Report.

Ownership arrangements

Aurora's *Regulatory Proposal* has been prepared on the basis that there will be no material change to its structure during the forthcoming *Regulatory Control Period*.

However, as indicated in chapter 2 of this *Regulatory Proposal*, in early 2010 the Tasmanian Government announced the establishment of an Expert Panel to undertake a review into the Electricity Supply Industry in Tasmania in accordance with Terms of Reference[4] issued by the Treasurer of Tasmania.

This Review is due to be completed by December 2011 and, depending on the outcomes of the Review, may result in changes to Aurora's business structure during the forthcoming *Regulatory Control Period*. Any structural changes that arise from this review will be assessed in accordance with the AER's cost pass-through mechanism.

2 Aurora Energy Pty Ltd, *Annual Report 2009-2010*, pages 68-69.

3 Ibid. page 10.

4 Electricity Supply Industry Expert Panel Website, *About Us*.

Aurora operates two core businesses

Aurora's structural arrangements comprise two core business lines:

- an energy business; and
- a distribution business.

There are also non-core operations of telecommunications and EziKey.

Aurora's business structure is depicted in figure 7. These operations are supported by services provided by the corporate divisions of Aurora.

While there are linkages along the value chain between the businesses, Aurora's overarching strategy is based on its capacity to create greater value than if there were four separate businesses through:

- economies of scale, which each of the individual operational business units would not be able to achieve if operating as separate businesses; and
- the efficiencies associated with the provision of centralised support services provided by the Strategy and Corporate Affairs; People and Culture; Office of the CEO; Governance; and Commercial Services divisions of the business.

Aurora's full time equivalent (FTE) staff numbers for the current *Regulatory Control Period* are shown in Table 5.

Figure 7

Aurora's business structure

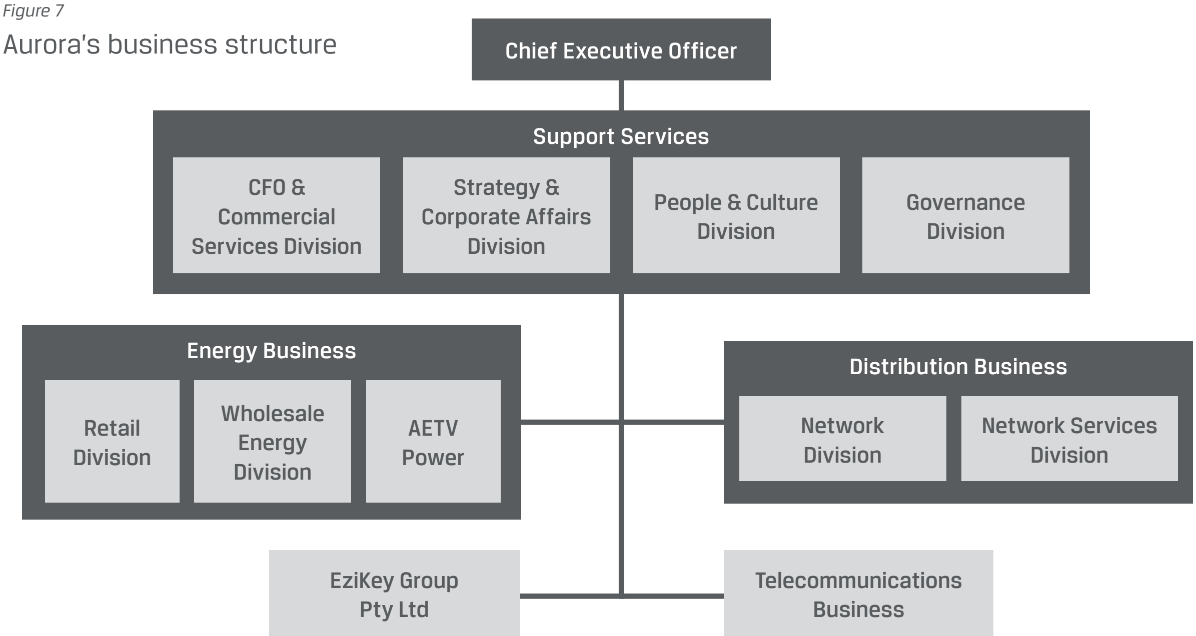


Table 5

Aurora's FTE numbers

Employees	2006-07	2007-08	2008-09	2009-10
Retail	153	149	180	252[1]
Wholesale	-	-	-	19
AETV	-	-	41	31
OCEO	7	7	7	7
People and Culture	-	12[2]	26	29
Strategy and Corporate Affairs	27	27	28	23
Commercial Services *	80	76	144[3]	158
Network	148	157	176	188
Network Services	698	706	682	688
EziKey	6	6	8	9
Telco	-	-	-	28
Total	**1,119**	**1,140**	**1,292**	**1,432**

* Includes the newly formed Governance division.
1 Includes project related activities.
2 Commencement of People and Culture centralisation from divisions.
3 Includes procurement and supply functions transferred from Network Services.

Distribution business

The purpose of Aurora's distribution business is to provide a safe and reliable, regulated monopoly that leverages regulated assets, institutional knowledge and new technology to increase regulated and non-regulated returns for the benefit of customers and shareholders. The primary objective is to be a customer-focused, innovative, sustainable and cost efficient business that makes a difference in the Tasmanian community.

The operations of the distribution business include internal service provision on the distribution system and service provision for Transend, in relation to operations and maintenance contracts on the transmission network. These services are provided by the Network and Network Services divisions.

The business provides a 24-hour seven-day a week service to approximately 229,400 residential and 50,400 commercial customers to ensure a safe, reliable electricity supply across the State.

Network has responsibility for the management, development and operation of the distribution system across Tasmania including poles, lines and substations. This is achieved through asset stewardship; network management; and works management, including contracts and service agreements for the provision of construction, operations and maintenance activities.

Network Services assists the Network division to manage and operate Aurora's distribution assets. The division oversees the distribution resource and response centres, designing and programming, including arranging contracts and service agreements for carrying out construction operations and maintenance of the distribution system.

It also has responsibility for the management of customer connections, meter reading, transmission capabilities, the Bass Strait Islands electricity system and the standards and compliance group, which includes the electrical inspection team and the Aurora Energy Training Centre. Personnel are also contracted by Transend to maintain the transmission system.

Network Services staff are positioned around the State in 17 locations, including the Bass Strait Islands, to provide an early fault response service for both the distribution and transmission networks.

The Network and Network Services divisions have always worked closely together, but their integration into one distribution business in 2010 has improved how the business plans and carries out work on the electricity system.

More detail in relation to the distribution business is included in chapter 4 of this *Regulatory Proposal*.

Energy business

Aurora's integrated energy business was established in January 2010 to bring together Aurora's wholesale, generation and retail operations in order to achieve the objective of optimising these assets. The primary objective of the energy business is to deliver customer and business outcomes consistent with a fully contestable market. This structure provides Aurora with a continuous value chain from generation to the customer. Access to generation means that the energy business can better manage its risks and ultimately reduce energy sourcing costs.

Generation activities are delivered through the wholly-owned subsidiary, Aurora Energy (Tamar Valley) Pty Ltd trading as AETV Power and through dispatch rights in relation to certain power stations. Further information in relation to this subsidiary is included later in this chapter under Subsidiary companies.

Wholesale Energy takes a portfolio approach to managing all energy market risks and returns for the business. It buys and sells energy, including physical generation and trades in energy contracts.

Retail is responsible for customer services including electricity sales to business and residential customers, account and case management, retail alliances, marketing, advertising and promotion, billing and complaints handling, call centre services and business support. As the incumbent retailer in Tasmania, Aurora Retail is obligated to supply all non-contestable customers under regulated tariffs.

Support services

Support services within Aurora are provided by the Commercial Services, Strategy and Corporate Affairs, People and Culture and Governance divisions; and the Office of the CEO.

Commercial Services and the Office of the Chief Financial Officer incorporates a range of Aurora corporate and whole-of-business services including accounting and finance; treasury management; supply chain services; facilities management; and energy risk management.

Strategy and Corporate Affairs has responsibility for leading Aurora's strategic direction. The division also has responsibility for a range of other whole-of-business activities, including public affairs and external relations; internal communications; sustainability strategy; market monitoring and policy development; and major business development.

People and Culture has responsibility for people strategy; culture and change management; safety; health and environment; recruitment; employee relations; remuneration and benefits; and organisational development.

Governance has responsibility for legal services; company secretarial; compliance; business risk; information management and for administrative purposes, internal audit. The General Manager Governance is also the Company Secretary and General Counsel.

The *Office of the CEO* provides support to the Chief Executive Officer and Company Secretary.

Subsidiary companies

Aurora has three fully owned subsidiary companies.

Aurora Energy (Tamar Valley) Pty Ltd, trading as *AETV Power*, which owns and operates the Tamar Valley Power Station.

AETV Power is governed by a Board of Directors comprising:

- Chairman John Hasker AM – Chairman, Aurora;
- CEO Michael Brewster – Chief Operations Officer, Aurora;
- Peter Davis – CEO, Aurora; and
- Darren Smith - CFO, Aurora.

AETV Power operates in accordance with "Governance Protocols for Aurora Energy Subsidiary Companies" and its charter which are both approved by the Aurora Board.

EziKey Group Pty Ltd (which trades as *WireAlert*) is the corporate structure which has been utilised to commercialise the broken neutral detector device developed by Aurora.

EziKey is governed by a Board of Directors comprising:

- Chairman Peter Davis – CEO, Aurora;
- John Devereaux – former General Manager – Network, Aurora;
- Mark Kuperholtz – Director, Global Connections Systems;
- Christopher Edwards – Managing Director, Moonraker Australia Pty Ltd; and
- Jack English – Associate Professor in Entrepreneurship, Australian Innovation Research Centre.

The CEO of EziKey is the General Manager – Network, Andre Botha.

EziKey operates in accordance with the "Governance Protocols for Aurora Energy Subsidiary Companies" and its charter which are both approved by the Aurora Board.

Auroracom Pty Ltd is the corporate structure which holds the telecommunications licence under the *Telecommunications Act 1997*.

The directors of Auroracom are:

- Darren Smith – CFO, Aurora; and
- Janelle O'Reilly – Company Secretary, Aurora.

Key relationships

As well as Aurora, the Tasmanian Government owns the transmission company, Transend Networks Pty Ltd and generation entity, Hydro Electric Corporation, trading as Hydro Tasmania. Aurora deals with these companies on a commercial basis. However, the entities liaise on appropriate issues, for example, emergency management.

Aurora revenues

Aurora derives its revenues from a number of different sources depending on the line of business involved.

Aurora's distribution business receives revenues for the provision of its Tasmanian distribution services based on prices which are set to recover its regulated revenue that is approved by the AER (previously OTTER) every five years and via customer contributions for connection activities. Aurora also earns revenues for access charges it recovers from users of its network assets such as the NBN.

The distribution business also receives revenues for the construction and maintenance activities the Network Services division undertakes on the transmission network on behalf of Transend; the distribution network on King and Flinders Islands on behalf of Hydro; for work undertaken on private electrical infrastructure belonging to electricity customers within Tasmania; and for work associated with the implementation of the NBN.

Aurora's generation activities provide revenues for the production of electrical energy that is sold into the National Electricity Market via settlements from AEMO.

Aurora's retailing activities receive revenues from its electricity customers from tariffs approved by the jurisdictional regulator for franchise customers in Tasmania and from market contracts for contestable customers in Tasmania, South Australia, Victoria, New South Wales, Queensland and the Australian Capital Territory and from contracts with its gas customers within Tasmania.

Aurora's telecommunication business earns revenues from the use of telecommunications capacity over its optical fibre network and for acting as agent of NBN Tasmania and NBNCo on the roll out of the NBN.

3.1. History of the development of Aurora's business

3.1.1. Establishment of Aurora

General electricity supply within Tasmania was first delivered within Tasmania in the early 1900s. Until 1998 the Hydro Electric Corporation (HEC), as it had now become, was the provider of all electricity services within Tasmania. The HEC developed and operated the entire suite of generation and network (transmission and distribution) facilities and was the retailer to all Tasmanian electricity consumers. This included King and Flinders Islands in Bass Strait.

On 1 July 1998 the Tasmanian Government implemented major reforms to the Tasmanian electricity supply industry (TESI). These reforms established two new Government owned companies: Transend and Aurora. These new companies would provide transmission, distribution and electricity retailing functions on mainland Tasmania, whilst the HEC would continue to provide generation and system control functions on mainland Tasmania and all functions on King and Flinders Islands.

The reforms, to separate the generation, transmission, distribution and retail functions, were in alignment with National Competition Policy[5] requirements and anticipated the introduction of competition in the generation and retail sectors when the Tasmanian electricity network was to be linked to mainland Australia with the commissioning of the Basslink interconnector.

Transend is the transmission network service provider, whilst Aurora is the distribution network service provider and retailer.

5 National Competition Council, *Major Areas of Reform – Electricity.*

Within the disaggregated TESI, Aurora had two key roles:

- As the "natural" monopoly for distributing energy to in excess of 250,000 Tasmanian electricity consumers under the *TEC*, Aurora was responsible for supplying electricity that was safe, reliable and economical. In return, Aurora was to receive a revenue stream that would ensure its ongoing viability; and
- As the franchise retailer in Tasmania, Aurora provided regulated retail services for the bulk of electricity consumers and assumed the purchasing risk for consumers in return for both service costs and an appropriate risk premium.

Following the Tasmanian Government's decision to join the National Electricity Market (NEM) in 2005, Tasmanian electricity customers became progressively eligible to nominate a retailer of their choice. The first tranche of contestability commenced on 1 July 2006 for those customers with energy consumption greater than 20 gigawatt hours.

This has been followed by successive tranches with lower consumption thresholds; with the impending commencement of the fifth tranche of contestability on 1 July 2011. The fifth tranche establishes retail competition for those commercial customers with consumption greater than 50 megawatt hours. Aurora remains the franchise electricity retailer for residential, or small, customers in Tasmania, however it is now one of five companies licensed to retail electricity in Tasmania and one of three licensed to retail natural gas.

In 2008 the Tasmanian Government purchased the then yet-to-be-completed Tamar Valley gas fired power station from Babcock and Brown[6]. The Government vested control of the newly acquired power station in Aurora and a fully owned subsidiary company of Aurora, Aurora Energy (Tamar Valley) Pty Ltd, was established in August 2008 to complete the construction of the power station and bring it to commercial operation.

In 2009 the Australian Government, in conjunction with the Tasmanian Government, commenced the roll-out of the NBN in Tasmania. Aurora was chosen as a partner for this work and to date NBN cable has been installed in three locations in Tasmania via Aurora's distribution infrastructure.

3.1.2. Historical development of the Tasmanian distribution network

The distribution network, as it is now known, came into being in the period 1910 to 1930. Prior to this period there were scattered distribution systems installed and operated by a number of private companies and local government agencies. The development of the distribution network was in its infancy.

The formation of the Hydro Electric Commission (HEC) occurred in 1914. Under this governance arrangement the integration of many local government assets occurred. These integrations continued well into the 1930s. A number of privately owned electrical assets such as the Hobart Gas and Launceston Gas Companies, were also purchased and these assets were amalgamated into an increasing distribution system.

The "hydro industrialisation" following World War II formed the backbone of what is now known as the Tasmanian generation, transmission and distribution systems. Of particular importance was that part of this expansion included the establishment of major substations primarily for heavy or large industry. Some examples of these substations are Railton (cement works), Risdon (zinc production), Emu Bay (pulp and paper production) and Trevallyn. The connection of the distributed customer base feeders was almost an add-on to these substations. This characteristic has a large bearing on the nature and topography of the current distribution network and contributes to Aurora having a number of very extensive rural feeder networks.

Prior to 1950, Hobart was supplied from Risdon and Creek Road substations at 11 kV. The Hobart plan from the mid 1950s saw the development of the then 22 kV and now 33 kV sub-transmission systems. The provision of 11 kV was mainly confined to the southern network and some other locations. Elsewhere, the supply philosophy was to have a distribution network of 110/22 kV systems.

The 1970s saw an increasing expansion of the distribution network and the establishment of infill 110/22 kV and 110/11kV substations. During this period the development strategy was to have 110 kV transmission rings around Hobart and Launceston with interspersed substations and distribution networks driving into the central commercial areas. Of note is that the 110 kV cable from Creek Road to North Hobart substations was oversized to become the initial stage of one of these 110 kV rings. In other areas infill substations continued to be built, as load densities did not require any shift from the prevailing strategy.

These supply strategies continued until the late 1990s with the planning of a Hobart 110/11 kV substation at McRobies Gully. Public pressure saw the abandonment of the overhead 110 kV transmission line that would supply this substation. With the need to provide reinforced security and upgrade supply within greater Hobart there was a resultant change of strategy and the reinforcement of the distribution sub-transmission network was instigated. This program came to be known as the Hobart Area Supply Upgrade (HASU).

HASU saw the major redevelopment of the East Hobart and West Hobart zone substations and medium redevelopment of the Sandy Bay, Claremont, New Town, and Derwent Park zone substations. The associated redevelopment of the Creek Road and Risdon substations was pivotal to upgrading the sub-transmission system from 22 kV to 33 kV and consolidating the sub-transmission system in the Hobart area.

6 *Tamar Valley Power Station Act (Tas) 2008*, Part 2.

3.1.3. History of Aurora's regulatory Determinations

The journey undertaken by Aurora since its creation in July 1998 has been, and remains, one of continuous improvement in its asset management capabilities, built upon the foundation of appropriate and aligned information, people and processes.

This has been undertaken in a changing commercial environment with increasing customer expectations.

Each *Regulatory Proposal* prepared for the Regulator and its related Pricing Determination outcomes represent a significant milestone in Aurora's organisational journey.

1999 Pricing Determination

The period from 1991 to 1998 was marked by a substantial cost reduction program as part of a drive by the Hydro to become more commercially focused and efficient. The drive to achieve greater efficiencies was achieved by cost cutting, with an initial across-the-board cut of 20 percent, followed by annual 4 percent reductions in the cost base each year. The majority of these reductions were achieved by means of labour reductions.

An outcome of the cost reduction program was a focus on upgrading the operational efficiency of the distribution network at the expense of the acquisition, storage, and analysis of data on the performance of the network. As a result Aurora's analytical capability was substantially reduced.

At the time of OTTER's 1999 Pricing Determination:

- Aurora's deficiency in data analysis meant it was unable to put forward substantive reasoning for the proposed level of operating and maintenance programs;
- Aurora (Hydro) had achieved significant cost reductions in previous years; and
- reductions in operating expenditures in the order of 30 percent were being applied to Pricing Determinations in other Australian jurisdictions.

Against that background, the Regulator's decision to reduce Aurora's operating expenditures by a further nine percent over the three years from 1 January 2000 was reasonable; however the combined impact of cost reductions to that point then amounted to around 45 percent since 1991.

Recognising the need for improved asset data, the Regulator accepted Aurora's submission for a $5 million data capture process to boost asset management efficiency, focused on a key asset class: poles.

2003 Pricing Determination

To assess and improve its asset management capabilities Aurora engaged the services of GHD to conduct biennial reviews, commencing in 2000. Unsurprisingly, a key recommendation of the initial GHD review was the need to improve data acquisition and management, to underpin evidence-based asset management decisions. Aurora accepted this recommendation and set about improving its asset data management capabilities.

Aurora's 2002 *Regulatory Proposal* was informed by improved knowledge of its pole assets, gained from the pole data capture project, and reliability performance. Whilst its asset knowledge in 2002 remained relatively poor, with good information confined to one major group of assets (poles), it was significantly better than it was in 1998.

Aurora's *Regulatory Proposal* included increased operating and capital expenditure and OTTER, informed by a review by PB Associates, approved almost all of Aurora's proposals. Part of that increased expenditure related to the provision of tools and resources to more effectively manage data.

During the *Regulatory Control Period*, Aurora carefully and progressively reviewed all of the dimensions of the network business, testing its existing capabilities and defining its expectations of efficient, capable asset management.

The results of these reviews led Aurora to the conclusion that there were a number of aspects of its asset management capabilities that required attention and investment. Funding for this investment had not been sought or provided for in the 2003 Pricing Determination.

Aurora invested in these activities at a level materially above that provided in the 2003 Pricing Determination. This decision resulted in an immediate profit reduction for Aurora.

Engineering competency and capacity was identified as critical to asset management capabilities. The previous extended cost-cutting had resulted in the responsibility for distribution network asset management being placed on an unsustainably small number of experienced engineers.

Aurora opted to invest substantially in rebuilding that capacity to a level that would sustain the business going forward and at the same time increase its overall asset management capabilities.

Similarly, in 2003 there was little focus on the customer service domain of the distribution business. A number of distribution customer service functions were still being performed by the Retail division and would need to transfer to the distribution business as a consequence of the introduction of retail competition.

Continuation of the journey to build data acquisition and management capability also required additional resources and supporting IT tools.

2007 Pricing Determination

Aurora's understanding of the expenditure required to efficiently and effectively operate and maintain Tasmania's electricity distribution system had progressed significantly since the 2003 Pricing Determination.

The expenditure proposals contained in Aurora's *Regulatory Proposal* had been constructed by way of a bottom-up approach. The resulting proposals and justifications had been scrutinised by a number of independent experts and benchmarked against outcomes achieved in other jurisdictions. The result of this process was a *Regulatory Proposal* that proposed material increases in both operating and capital expenditure programs. Aurora considered these increases were appropriate given the nature and condition of the infrastructure being managed and the environment in which it now operated.

Notwithstanding that Aurora's network management capability had been assessed by GHD as near appropriate best-practice, Aurora acknowledged that it could and should achieve more. In particular, further improvements in asset data and condition assessment proposed for the *Regulatory Control Period* would bring it closer to appropriate best practice asset management.

Whilst Aurora's *Regulatory Proposal* included these increased operating and capital expenditures they were for the large part approved by OTTER following a review by Wilson Cook and Associates (Wilson Cook).

Aurora has realised a large part of its allowed expenditure during the current *Regulatory Control Period* and considers that investment in the network is now at an appropriate level and that consolidation of expenditure can now occur. Asset failures have not increased and reliability levels have remained consistent with the requirements of the *TEC*.

4. Aurora's distribution business

4. Aurora's distribution business

The distribution business incorporates an overarching function that sets the overall asset management philosophy and direction; and provides operations and maintenance activities within the two distinct divisions of:

- Network; and
- Network Services.

As the only licensed provider of distribution services within the Tasmanian jurisdiction, Aurora has adopted a balanced approach to ensure that the management of the distribution business reflects and aligns both the business and the regulatory objectives and therefore delivers appropriate long-term customer outcomes, in terms of price, service and reliability, together with business sustainability.

This approach recognises that long-term business sustainability can only be delivered through a careful balance of:

- outcomes delivered for customers and the community;
- commercial outcomes for the business; and
- the development of business capability including having the right people, processes, partners, information and systems.

The distribution business is an asset management business combining asset ownership, asset decision-making and asset service provision. This business is a core element of the Aurora business.

An effective distribution asset manager makes and executes decisions on its asset base, over the longer term, that seek to:

- satisfy its customers;
- deliver appropriate business outcomes for its shareholders; and
- manage the risks it poses for the community it serves, including its employees.

The application of asset management strategies, aligned with the investment drivers of risk, capacity, reliability, lifecycle cost and customer service, ensure Aurora continues to deliver outcomes that:

- build the knowledge base of its assets so that Aurora can continue to develop least cost maintenance and replacement programs;
- build business capability through information systems focused on data acquisition and utilisation which:
  - › underpin an intelligent network model allowing performance data analysis of system conditions (e.g. voltages, loads, protection information, asset condition data); and
  - › present the information derived from this data in real time;
- build on the success of reliability programs ensuring compliance with the challenge of the *TEC* imposed reliability standards, by continuing to improve the capture of network reliability data, its analysis and use in Aurora's network planning and asset management processes;
- arrest the rising age of its asset base through the implementation of targeted asset replacement programs;
- seek to defer significant network investments through the use of demand management strategies;
- continue and develop its condition and risk-based assessment of network assets;
- continue to develop its market systems, processes and structure to ensure compliance with the NEM and further tranches of contestability; and
- embed a customer service and delivery culture into the business to maximise internal and external, mutually beneficial, customer outcomes.

Business outcomes

As noted previously, Aurora's Memorandum of Association requires Aurora to:

- operate its activities in accordance with sound commercial practice; and
- maximise its sustainable return to its shareholders.

This focus on commercial outcomes is also reflected in Aurora's whole-of-business strategy which includes a key group strategic objective "to deliver sustainable customer price outcomes and appropriate returns to our Shareholders".

The critical business outcomes for the distribution business are that:

- Aurora and its shareholders achieve appropriate commercial financial returns on the investments that are made;

- Aurora is able to attract and retain the highly skilled and motivated staff it needs to continue in business and deliver the right outcomes; and
- Aurora can manage the various risks it faces in the distribution business to acceptable levels.

These objectives depend on:

- the ability of Aurora to secure sufficient revenue streams; and
- a sound operating framework to provide long-term direction, stability and certainty.

In a regulated environment to secure such income streams Aurora must:

- ensure its asset management is delivering improving value for the customers and the community; and
- manage capital and operating expenditure within the allowances provided and seek to drive better value from each investment dollar.

Through this Revenue Determination process the AER exerts a powerful influence over Aurora's ability to achieve its strategic objectives with regard to the distribution business. Aurora emphasises that while adequate funding is a major prerequisite for business viability, it is not the only requirement. Both the *Rules* and the *TEC* require, and indeed both the AER and OTTER in the past have demonstrated, consideration of business viability when making their Revenue Determinations.

Customer outcomes

Critical to Aurora's long-term success and viability as a distribution business is its ability to understand customer expectations and to deliver to those expectations. Aurora has played an active role in researching customer needs and expectations and working with jurisdictional bodies to ensure that the regulatory framework supports the pursuit of those expectations where they are reasonable and sustainable.

Aurora has undertaken, and continues to undertake, substantial research of its customers to understand the values, wants and needs of those customers when dealing with a Distribution Network Service Provider.

This research is undertaken on an ongoing basis utilising such methods as event tracking surveys, analysis of the causes and contributing factors of customer complaints and one-off surveys.

Event tracking surveys are focused on customers that have had dealings with Aurora following a general enquiry, a power system interruption (planned and unplanned) or a service connection request; and provide valuable insight into Aurora's customer's perceptions and needs. Aurora is then able to fine tune the way it manages these interactions to better meet its customers' expectations.

One-off surveys, allow Aurora to undertake detailed analysis of customers' expectations and the value they impose on the services that are provided as part of their electricity supply.

The type and number of complaints that Aurora receives from its customers also provides valuable feedback on what customers expect of their electricity supply and how they expect Aurora to deal with problems when they arise.

Aurora's customer research has consistently demonstrated, over time, that the three things most important to its customers in determining their perceived value are:

- price;
- the provision of adequate reliability of supply (both frequency and duration of interruptions); and
- the effective provision of customer service.

An improved knowledge of:

- customer satisfaction by segment and region;
- which reliability measures best align with customer's preferences; and
- what level of reliability customers are willing to pay for (by region and segment);

has enabled Aurora to both:

- refine base case operational activities to provide better outcomes for customers; and
- develop options for performance improvements that provide effective outcomes (as described by customers) for an efficient price.

A sound operating framework

Aurora has adopted an open relationship with its jurisdictional regulator for the purpose of developing a sound operating framework. Aspects of the operating framework include:

- regulations;
- regulatory incentives;
- investment review procedures; and
- a performance measurement framework.

A key principle of the framework has been to ensure maximum alignment of the business management of Aurora and the operating framework. To that end Aurora has worked co-operatively and closely with OTTER to develop and implement an increasingly sophisticated framework. Aurora will continue to emphasise the need for the operating framework to:

- be as low-cost and administratively simple as practicable;
- encourage the business to consider and act in the best long-term interests of the customers, community and shareholders; and
- include sufficient certainty to facilitate long-run investment and best practice asset management.

Community outcomes

Community expectations and regulatory oversight of Aurora's distribution business have increased and broadened significantly over recent years. These standards and expectations cover public and employee safety, environmental management and corporate citizenship.

Aurora has established programs designed to maintain a safe, healthy and productive work environment for all employees, contractors, visitors and members of the public. Aurora's electrical safety risk management has led to a number of important community programs, including the long-established Electrical Safety in Schools program, the *Safe Growing* campaign aimed at rural property owners and the *Look Up Look Out* public awareness campaign targeted at the agricultural and civil contracting industries, which have been over-represented in electrical safety incidents. Aurora also provided CablePI electrical safety sensors to more than 210,000 Tasmanian residential customers in 2009-10 in order to reduce the incidence of electric shocks in customer premises and to identify potentially lethal faults on the distribution network[1].

An increasing number of State and national environmental regulations must also be met by Aurora, and community expectations in relation to the company's environment impacts have grown significantly. Community and regulatory oversight of Aurora's environmental practices and impacts now include:

- oil spill response processes and resources;
- procedures to minimise the potential for pollution entering waterways;
- noise minimisation;
- mitigation of bird strikes on Aurora infrastructure;
- weed management;
- protection of threatened plants;
- guidelines for work around indigenous and non-indigenous heritage items;
- storage and handling of oil-filled equipment;
- control measures for hazardous substances;
- erosion and sediment control;
- acid sulphate soil mitigation;
- reductions in greenhouse gas emissions; and
- reduction in waste disposal and increased recycling.

1 Aurora Energy Pty Ltd, *Annual Report 2009-2010*, page 36.

One of the most resource-intensive areas of community interest is vegetation management. Vegetation clearing contractors are utilised to reduce bushfire hazards and minimise the potential for vegetation to impact on Aurora's infrastructure, particularly poles and overhead wires. There have been increasing interactions with a number of customers and community groups in relation to vegetation clearance over recent years.

Aurora also works with communities to mitigate the visual impact of its infrastructure. For example, a number of communities have worked within Aurora's guidelines to decorate poles and other assets.

Distribution business management

The General Manager – Network, and the General Manager – Network Services and the joint Distribution Executive Team, which includes the divisional Group Managers responsible for the core operational business units of the divisions, are responsible for the day-to-day management of the distribution business and act in accordance with the delegations of Aurora.

The Distribution Executive Team is responsible for the overall business governance of the distribution business. The Executive Team is responsible for setting the strategic direction and objectives for the distribution business and for monitoring the achievement of these objectives. It also approves and monitors the business plans and operating budgets submitted by the divisional managers and reports on the performance of those plans and budgets to the Aurora Board via the General Managers.

The distribution business FTE staff numbers for the current and forthcoming *Regulatory Control Periods* are shown in Table 6.

Table 6

Distribution business FTE numbers

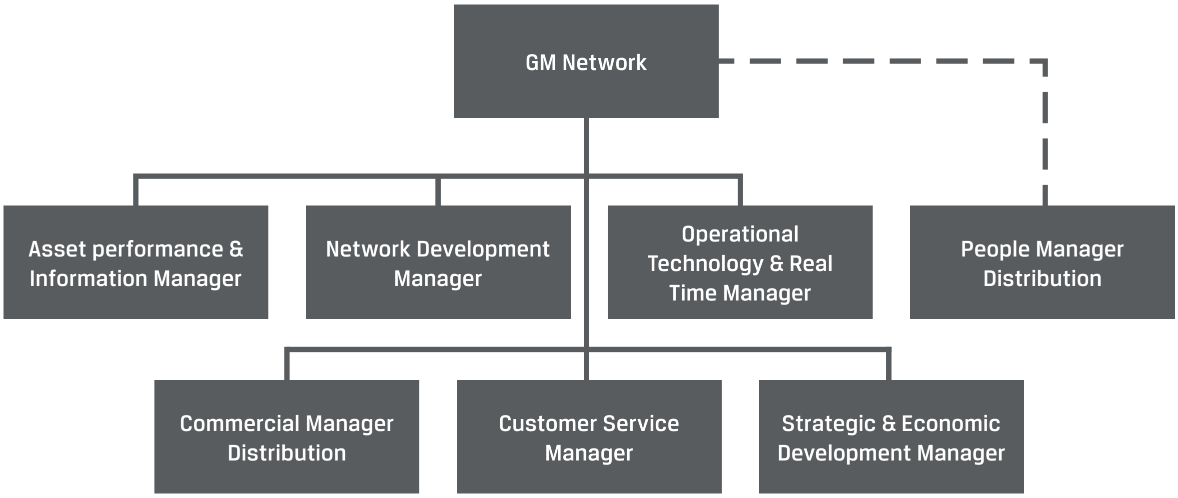
Employees	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
	Actual	Forecast						
Network division	188	154	150	150	150	150	150	150
Network Services division	688	675	673	673	673	673	673	673
Total	**876**	**829**	**823**	**823**	**823**	**823**	**823**	**823**

Network division

Network division is primarily responsible for the distribution asset strategy and direction. The Network division is headed by the General Manager – Network and comprises seven functional operating groups, each headed by a Group Manager. The structure of the Network division is shown in Figure 8.

Figure 8

Network division organisational structure



Asset Performance and Information Management

The Asset Performance and Information Management group manage the asset maintenance portfolio of the distribution assets. The structure of this group recognises the growing importance of secondary assets in the future of the distribution network and the importance of asset information in all of Aurora's distribution operations.

Network Development

The Network Development group is accountable for managing the distribution network development function and making the network more efficient. The group is charged with the planning and execution of the development of the distribution network to meet customer growth using conventional and non-network solutions.

Operational Technology and Real Time

The Operational Technology and Real Time group is accountable for the operation of the network in real time; and data management and the operation of the systems that provide that data.

Commercial

The Commercial group provides finance services across the entire distribution business (both Network and Network Services). The group also provides all revenue and billing activities, as well as managing the regulatory interface and compliance obligations.

The commercial group also liaises with the corporate and shared services divisions to ensure optimal distribution business input to group requirements and the efficient delivery of shared services to service the distribution business needs.

Customer Service

The Customer Service group supports a strong distribution focus on customer services. The group centralises all customer-related roles and functions, including business support and customer connections and interactions into a single customer centric team.

Strategic and Economic Development

The Strategic and Economic Development Manager provides the link between distribution strategy, revenue and pricing considerations; and the outcomes of the regulatory regime in which Aurora operates its distribution business.

People

The People group is a subset of Aurora's People and Culture division and has responsibility for people strategy, culture and change management, safety, health and environment, recruitment, employee relations, remuneration and benefits and organisational development for the entire distribution business.

The Network division FTE staff numbers for the current and forthcoming *Regulatory Control Periods* are shown in Table 7.

Table 7

Network division FTE numbers

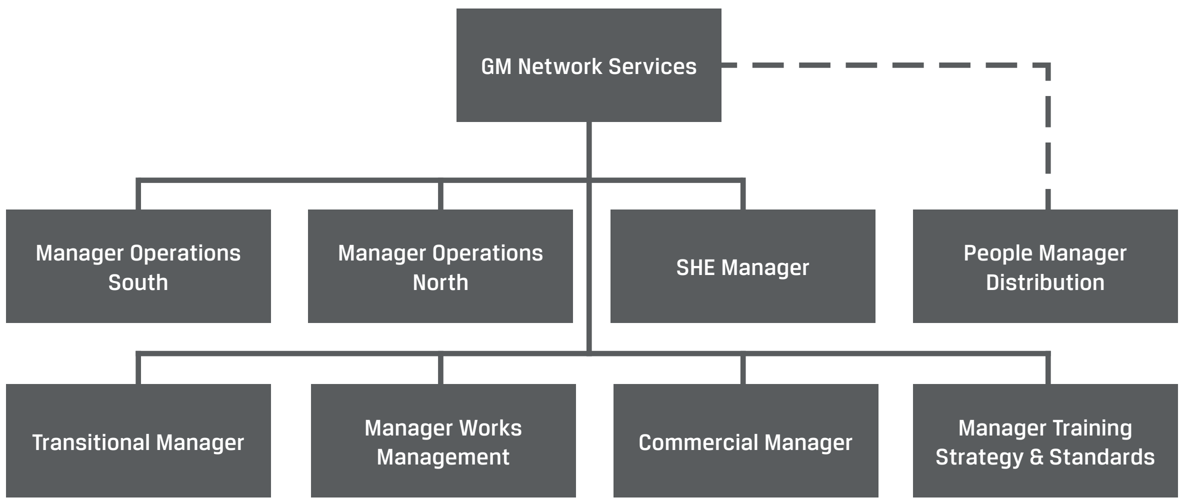
Employees	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
	Actual	Forecast						
Distribution Capability Improvement	13							
Local Asset Management	21							
Market Services	33							
Office of the General Manager	2	2	2	2	2	2	2	2
System and Asset Management	27							
System Operations	44							
Asset Performance and Information		22	22	22	22	22	22	22
Commercial Management	20	21	20	20	20	20	20	20
Customer Service	21	41	40	40	40	40	40	40
Graduates	7	6	6	6	6	6	6	6
Network Development		14	14	14	14	14	14	14
Operational Technology and Real Time		47	45	45	45	45	45	45
Strategic and Economic Development		1	1	1	1	1	1	1
Total	**188**	**154**	**150**	**150**	**150**	**150**	**150**	**150**

Network Services division

Network Services division is responsible for the provision of the field staff to construct, maintain and operate the distribution network. The Network Services division is headed by the General Manager – Network Services and comprises eight functional operating groups, each headed by a Group Manager. The structure of the Network Services division is shown in Figure 9.

Figure 9

Network Services division organisational structure



Operations (South and North)

The Operations South and North groups comprise three main sub-groups:

- Works Delivery;
- Scheduling; and
- Operational Delivery.

Works Delivery

The Works Delivery sub-group is managed on a regional basis (South, North and North West) and provides services within Aurora and to Transend and Hydro in the areas of:

- construction, operations and maintenance activities on the distribution system;
- management of customer connections;
- construction, operations and maintenance activities on the transmission system;
- operation and maintenance of the power stations and distribution system on King and Flinders Islands;
- maintenance activities in generation power stations and switchyards; and
- preparation work to support NBN fibre installation; and operations and maintenance of installed NBN fibre.

Scheduling

The Scheduling sub-group manage the scheduling and coordination of work activities and resources to meet work program requirements. It is responsible for ensuring the effective implementation of the work packages, including managing change to the packages, prioritisation, allocating resources and providing progress reporting.

Operational Delivery

The Operational Delivery subgroup comprises the functions of asset inspection, meter reading, vegetation management and oil management. It is responsible for meeting client service expectations in the delivery of these functions.

Transitional Manager

This role has the responsibility for the integration of Service Connections into the Works Delivery sub-group and the transfer of Meter Reading to the Operational Delivery sub-group and will support the structural transition.

Commercial

The Commercial group is responsible for business strategy and implementation, project management, client management and key subcontractor arrangements, with the final three areas being grouped together to maximise commercial synergies and internal expertise.

Business strategy and implementation

the business strategy and implementation team is responsible for the facilitation of business planning and direction and overseeing implementation of key strategic initiatives.

Projects

The projects team is responsible for delivery of all major and strategic projects undertaken in the distribution business.
The client management area is responsible for key work relationships and commercial interactions with clients while key subcontractor arrangements are also managed out of this broad area of the business.

Works Management

The Works Management group comprises the Planning and Design teams.

Planning

The Planning team plans, prioritises and coordinates work to best utilise internal and external resources to deliver on customer expectations in a safe and productive manner, and includes the following key functions:

- facilitating, planning and coordinating the development of the distribution work program;
- development of resourcing plans to support workforce planning and skills acquisition for future program requirements;
- development of the 12 month resourcing plan to inform:
  (a) ability to deliver;
  (b) internal resourcing;
  (c) external resourcing requirements via the design and construct contract;
  (d) 12 month prioritised design plan; and
  (e) ensure the plan maximises work opportunities;
- development of three month forward resourcing plan and excess work;
- development of one month prioritised packages of work for Works Delivery; and
- monitor and report on progress against delivery of the program.

Design

The Design team produce designs and estimates to support delivery of the distribution program of work in alignment with asset strategies and client and customer requirements, and includes the following key functions:

- designs for the electrical distribution network;
- designs for customer-generated work;
- safety, environmental, and heritage assessments and management as part of the designing process;
- easement and wayleave acquisitions and negotiations; and
- estimates and quote facilitation to support planning, scheduling and construction functions.

Training Strategy and Standards

The Training Strategy and Standards group provide training, compliance and auditing functions, primarily for the distribution business but also for the broader energy industry in certain instances. The group's functions largely underpin the safe system of work within the distribution business; and is closely aligned with the SHE function.

The Training Strategy and Standards Group comprises the Training Centre; Standards, Audit and Licensing; Compliance Testing; AMI; and Electrical Inspection teams.

Training Centre

The Training Centre is a registered training organisation that delivers nationally accredited training in the powerline area at a Certificate III and Certificate IV level. The centre also delivers other technical training services to the business and industry generally, which includes power systems safety rules accreditation, NBN training, live line, rescue procedure and electrical testing. Much of this training is centred on the minimum requirements for access to work on the distribution network.

Standards, Audit and Licensing

The Standards, Audit and Licensing team manages Aurora's electrical contractors licence under the *Occupational Licensing Act 2005* and ensures compliance with the Act in all areas of electrical work performed within the distribution business. This is done with an audit team that audits Aurora's field crews and contractors for work practices and quality against work procedures, standards and legislation. The team also develops work procedures and standards for the field workforce and provides technical advice to the workforce, contractors and customers and manages the calibration of testing instruments. The team also manages the quality management system for Aurora which incorporates the Training Centre, NEM metering, procurement, accounts payment and contract management.

Compliance

The Compliance team is a small team that is responsible for testing and repairs of Aurora's electrical equipment such as line mats, fuse sticks, ladders and lifting equipment. All tests are performed against Australian Standards and are performed in all depots, including the Bass Strait Islands. This testing and repair service is essential to the safety and productivity of the field workforce.

AMI

The AMI team is responsible for the management of the accredited meter installer scheme and the implementation of other contractor accreditation for the distribution business. This ensures there are clear standards for contractors working on the distribution system with the appropriate training in place.

Electrical Inspection

The Electrical Inspection team provides an electrical inspection service of the work performed by electrical contractors on consumer's private electrical infrastructure, both domestic and industrial against AS/NZ-3000. The team also provide a 24 hour, seven day fire and shock response service state wide. This work is performed under contract to Workplace Standards Tasmania and the contract is due for renewal on 30 June 2012.

SHE Team

The SHE team is responsible for safety, health and environment initiatives across the distribution business. This team assists Aurora to achieve and maintain a safe, healthy and productive work environment for all employees, contractors, visitors and members of the public.

The Network Services division FTE staff numbers for the current and forthcoming *Regulatory Control Period* are shown in Table 8.

Table 8

Network Services division FTE numbers

Employees	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
	Actual	Forecast						
Commercial Management	31	31	26	26	26	26	26	26
Safety, Health & Environment	8	8	8	8	8	8	8	8
Office of the General Manager	10	5	9	9	9	9	9	9
Works Management	48	47	45	45	45	45	45	45
Training Strategy & Standards	50	49	50	50	50	50	50	50
Operations – South – North	487	477	492	492	492	492	492	492
Apprentices	54	58	43	43	43	43	43	43
Total	**688**	**675**	**673**	**673**	**673**	**673**	**673**	**673**

4.1. Governance arrangements

The distribution business operates under an operational model whereby activities are broken down into programs called 'threads'.

Corporate management and budgeting occurs within the Aurora corporate office.

In order to prepare operating and capital expenditure forecasts, Aurora followed the same process as with previous *Regulatory Proposals*, in particular to:

- prepare forecasts by thread for the *Regulatory Control Period*, along with corporate cost forecasts;
- convert these forecasts to the nominated operating and capital expenditure categories; and
- include these forecasts, along with appropriate documentation to support the forecasts, in, or with, the *Regulatory Proposal* provided to the AER.

4.1.1. Thread management

In its asset management activities, Aurora uses a 'thread management' approach whereby each asset class used by Aurora has a thread associated with it.

A 'thread' comprises staff from Network and Network Services divisions involved in the planning, design, construction and maintenance of the asset class. This provides an 'end-to-end' communication process across the distribution business.

Threads also provide a convenient mechanism for grouping assets for planning and expenditure purposes.

Outside of the thread framework sit functions that provide common support services to all threads: for example, finance, human resources, regulatory.

A thread may be associated with Standard Control, Alternative Control, Negotiated Services or Unregulated work as classified by the AER. Following are the threads associated with the development of the Aurora work program:

- connection assets;
- meters;
- road lighting;
- customer-generated work;
- system development;
- system operations;
- ground mounted substations;
- HV regulators;
- underground system;
- zone substations;
- overhead system;
- structures;
- power quality;
- protection and control;
- reliability;
- vegetation management; and
- network IT.

Thread leaders are responsible for the planning and development of programs and budgets associated with the assets in a particular thread.

4.2. Key information systems to provide regulated services

Aurora's key information systems, which are detailed in the Distribution Network ISG Strategy, appended as an attachment to this *Regulatory Proposal,* comprise a mixture of standard commercial systems and in-house solutions that have been developed to support business processes and analysis.

The Aurora Distribution Network ISG Strategy is a 10 year strategy that achieves technology consolidation and simplification and enhanced strategic capabilities by implementing a foundation to enable Aurora's distribution business to thrive in a "smart" world. The strategy realises a long term vision that transforms Aurora's IT capabilities from their current state into a strategic, business enabling platform.

The goal of this strategy is to enable and support Aurora's aspirational goal, "To not contribute to any price increases to the customer as a result of our efforts", and specifically to facilitate the achievement of the strategic metrics of expenditure cost reduction through increasing operational efficiency over the forthcoming *Regulatory Control Period*.

The systems have been grouped into the following categories:

- fixed asset management;
- power system management; and
- market services management.

Fixed asset management

The objective of Aurora's approach towards asset management is to ensure that electricity is delivered safely, reliably and economically while respecting the environment. Aurora's asset replacement strategies are designed using the best available techniques appropriate to the criticality and value of the assets and incorporate a whole-of-life and risk-based approach.

The IT solutions currently supporting Fixed Asset Management are:

- DINIS - power flow analysis;
- WASP – works management, design and asset condition;
- WASP BASIX – works planning;
- G-Tech – GIS and network model; and
- Spatial Data Warehouse – with a suite of in-house process and analysis tools.

Power system management

The objective of power system management (system fault and operations) is to "operate the distribution system to provide and maintain customers to agreed service standards while accommodating asset management activities and public safety considerations".

There are three key processes to achieve this objective:

- system management – the overall management (monitoring and control) of the performance of the network;
- fault management– the efficient and effective management of power system faults or emergency situations which involve the power system; and
- system access– the safe and efficient provision of access to the power system for asset management activities such as construction and maintenance.

The IT solutions currently supporting Power System Management are:

- iFIX Intellution SCADA system;
- InService OMS solution;
- Avalanche system from TVD;
- critical customer database;
- G-Tech; and
- WASP.

Market services management

Currently, Aurora is undertaking a major upgrade of some of these systems to enable it to interface seamlessly with the Tasmanian electricity retailers and their customer and billing systems.

Aurora's approach to these system developments has been on a 'just-in-time' basis with the implementation of a mix of manual and semi-automated systems and processes; with a view to enhancing functionality, the level of automation and capacity as volumes, business needs and regulatory obligations develop and increase.

Major systems developed have included:

- meter data management (MDMS) by Gentrack;
- service order management (SOM) by Brave Energy;
- TVD CSC - works management;
- distribution billing and interfaces to other Network systems; and
- Aurora Retail systems and the national retail market through the market integration layer (MIL).

4.3. Unregulated services and revenue

Aurora undertakes a range of activities that are currently not subject to economic regulation.

Table 9, extracted from Aurora's Ring-fenced accounts, provides a split of Aurora's unregulated revenues (in nominal terms) during the previous and current *Regulatory Control Periods*.

Unregulated Other

The Unregulated Other category primarily covers revenue from:

- sales made by Aurora's gas retail business;
- operations of Aurora's telecommunications business, including capital contributions towards Telco activities;
- services provided by the Network Services division to external parties; and
- fees for gas connections and reconnections.

Unregulated Retail

The Unregulated Retail category primarily covers revenue from:

- electricity sales to contestable customers in Tasmania and mainland Australia;
- monies from Government to fund Community Services Obligations[2];
- interest on overdue accounts; and
- fees for electricity connections, reconnections and disconnection services.

Unregulated Distribution

The Unregulated Distribution category primarily covers revenue from:

- contestable metering services provided by the distribution business;
- the provision of public lighting services; and
- customer contributions towards unregulated capital works performed by Aurora.

Under the regulatory framework proposed by the AER in the *Framework and Approach Paper*, the following components of the categories in the table will be regulated in some form:

- part of the services provided by the Network Services division to external parties; and
- provision of public lighting services.

2 Aurora Energy Pty Ltd, *Annual Report 2009-2010*, at page 90.

Table 9

Aurora's unregulated revenues

Category	2003-04 ($'000)	2004-05 ($'000)	2005-06 ($'000)	2006-07 ($'000)	2007-08 ($'000)	2008-09 ($'000)	2009-10 ($'000)
Unregulated Other	807	36,204	47,566	34,933	30,400	27,608	70,083
Unregulated Retail	285,312	280,778	286,310	335,277	405,295	479,069	581,501
Unregulated Distribution	4,393	5,440	6,016	5,624	3,586	4,585	7,360
Total	**290,512**	**322,422**	**339,892**	**375,834**	**439,281**	**511,262**	**658,944**

4.4. Overview of the network

Aurora constructs, maintains and operates the electricity distribution network on mainland Tasmania in accordance with the distribution licence issued by OTTER. Aurora also constructs, maintains and operates the electricity distribution network on King and Flinders Islands on behalf of Hydro Tasmania.

4.4.1. Distribution connection points

Aurora's distribution network is primarily connected to the transmission system owned and operated by Transend at 41 terminal substations throughout Tasmania.

Due to historical infrastructure design and the remoteness of some distribution assets, there are a further five locations where the distribution network feeders connect directly to assets owned by Hydro.

Table 10 provides an overview of the connection points for Aurora's distribution network within the Tasmanian jurisdiction.

Table 10

Aurora's connection points

Connection	Connection Company	Connection Voltage (kV)	Connection Points	Type
Arthurs Lake	Transend	6.6/22	1	Distribution
Avoca	Transend	22	4	Distribution
Bridgewater	Transend	11	10	Distribution
Burnie	Transend	22	12	Distribution
Chapel St	Transend	11	17	Distribution
Creek Rd	Transend	33	8	Sub-transmission
Derby	Transend	22	3	Distribution
Derwent Bridge	Transend	22	1	Distribution
Devonport	Transend	22	11	Distribution
Electrona	Transend	11	8	Distribution
Emu Bay	Transend	22	4	Distribution
Fisher	Hydro	22	1	Distribution
George Town	Transend	22	10	Distribution
Gordon	Hydro	22	1	Distribution
Hadspen	Transend	22	8	Distribution
Kermandie	Transend	11	4	Distribution
Kingston	Transend	11	12	Distribution
Knights Rd	Transend	11	6	Distribution
Lindisfarne	Transend	33	6	Distribution
Meadowbank	Transend	22	3	Distribution
Mowbray	Transend	22	10	Distribution
New Norfolk	Transend	22	6	Distribution & Sub-transmission
Newton	Transend	22	1	Distribution
North Hobart	Transend	11	22	Distribution
Norwood	Transend	22	8	Distribution
Palmerston	Transend	22	3	Distribution
Port Latta	Transend	22	2	Distribution
Queenstown	Transend	22	4	Distribution
Railton	Transend	22	8	Distribution
Risdon	Transend	33	7	Sub-transmission
Rokeby	Transend	11	10	Distribution

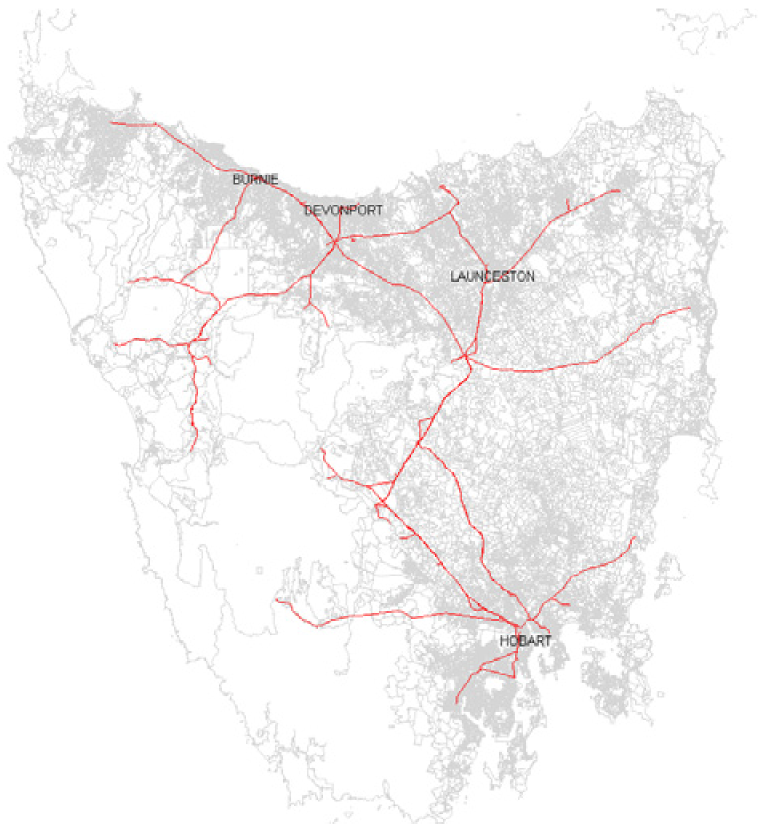
Connection	Connection Company	Connection Voltage (kV)	Connection Points	Type
Rosebery	Transend	44	2	Distribution & Sub-transmission
		22	3	Distribution
Savage River	Transend	22	1	Distribution
Scottsdale	Transend	22	5	Distribution
Smithton	Transend	22	5	Distribution
Sorell	Transend	22	8	Distribution
St Marys	Transend	22	4	Distribution
Todds Corner	Hydro	22	1	Distribution
Trevallyn	Transend	22	17	Distribution
Triabunna	Transend	22	3	Distribution
Tungatinah	Transend	22	4	Distribution
Ulverstone	Transend	22	8	Distribution
Waddamana	Hydro	22	1	Distribution
Wayatinah	Hydro	11	2	Distribution
Wesley Vale	Transend	11	1	Distribution

As noted above, Aurora's distribution network is primarily connected to Transend's transmission system. Transend has a 220 kV and a 110 kV transmission network that connects generators (including Hydro) to the distribution system, major industrial customers and Basslink. This system comprises 3,469 circuit kilometres of transmission lines, 47 substations and nine switching stations as well as a telecommunications system and control centre.

Figure 10 illustrates the extent of Transend's transmission network in Tasmania.

Figure 10

Transend's transmission network



To achieve the optimum network solution, Aurora and Transend jointly plan and develop strategies for the management of the transmission and distribution assets and the associated networks. This approach facilitates the progress of distribution requirements and issues that directly and indirectly affect both networks.

4.4.2. Sub-transmission network

Aurora further distributes the electricity supply via its 16 zone substations, which are predominately located in the greater Hobart area. These sites are shown in Table 11.

Table 11

Aurora's zone substations

Zone Substation	Type	Primary voltage (kV)	Secondary voltage (kV)
Bellerive	Urban - major	33	11
Cambridge	Urban - major	33	11
Claremont	Urban - major	33	11
Derwent Park	Urban - major	33	11
East Hobart	Urban - major	33	11
Geilston Bay	Urban - major	33	11
Gretna	Rural - minor	22	11
New Norfolk	Rural - minor	22	11
New Town	Urban - major	33	11
Richmond	Rural - minor	22	11
Sandy Bay	Urban - major	33	11
Todds Corner	Rural - minor	6.6	22
Trial Harbour	Rural - major	44	22
Wayatinah	Rural - minor	11	22
West Hobart	Urban - major	33	11
Westerway	Rural - minor	22	11

General statistics for Aurora's zone substations are shown in Table 12.

Table 12

Zone substation statistics

Zone Substation	No. of feeders	Connected MVA	Installed capacity (MVA)	Firm capacity (MVA)	Maximum demand (MVA)
Bellerive	8	44	45	22.5	20.6
Cambridge	12	41	40	20	11.5
Claremont	10	52	45	22.5	24.1
Derwent Park	10	66	45	22.5	21.6
East Hobart	11	89	90	45	30
Geilston Bay	9	49	45	22.5	26
Gretna	2	7	2	1	0.9
New Norfolk	3	28	10	7.5	7.5
New Town	8	46	45	22.5	21.4
Richmond	3	27	5	2.5	4.3
Sandy Bay	13	84	90	45	39.7
Todds Corner*	1	0	6	3	0.0
Trial Harbour	3	9	40	20	2.4
Wayatinah	3	6	2	1	1.2
West Hobart	15	98	90	60	41
Westerway	2	7	2	1	1.3

* Todds Corner zone substation is used for emergency system supply only.

4.4.3. Distributed generation

Aurora encourages the connection of embedded renewable generation to its network and continues to receive a reasonable number of connection enquiries for distributed generation units, including:

- micro: wind and solar;
- small: mini hydro, wind, solar, tidal; and
- medium: wind, mini-hydro and cogeneration (gas).

The existing distributed generation sites connected to the distribution network are shown in Figure 11. Their size is generally less than 3 MW and their location has had little impact on deferment of major capital works. Due to the size and nature of these generating facilities they do not provide any form of network support.

Figure 11

Distributed generation sites

Aurora has continued to experience a high number of photovoltaic system connection applications despite the removal of the Government grants supporting solar panel installation. These recent changes to legislation have resulted in the re-appraisal of previously uneconomic renewable generation projects and this will impact Aurora in future years.

Aurora currently has approximately 3,500 connected residential photovoltaic systems. Unit sizes range from 1.0 kW – 6 kW and typical sizes include 1.0 kW and 3.0 kW units.

4.4.4. Retailer interactions

All five licensed retailers within the Tasmanian jurisdiction buy electricity through the NEM and sell it to customers. Aurora is the sole electricity distributor in the Tasmanian jurisdiction and supplies electricity to all customers connected to the distribution network. Aurora recovers its costs of supply from the retailers of these customers in accordance with its Distribution Determination.

4.5. Key characteristics of Aurora's network

Aurora's distribution network:

- delivers electricity safely, reliably and efficiently to achieve the best outcomes for the Tasmanian community;
- comprises a network of power poles, cables, wires and smaller transformers to deliver the electricity from terminal and zone substations to homes and businesses in Tasmania;
- delivers electricity to Tasmanians living across an area of approximately 67,800 square kilometres. Much of Aurora's distribution network traverses rugged and isolated terrain;
- is primarily connected to the transmission network operated by Transend but does have a number of other feeder connections to Hydro generator sites.

4.5.1. High voltage network

Aurora's HV distribution network distributes electricity at either 44, 33, 22 or 11 kV via 317 distribution feeders. There are 30,262 distribution substations that further reduce the voltage to 230/400 volts to supply the majority of Aurora's customers through the low voltage network. There are a number of HV customers, with their own distribution substations that take electricity supply directly at 22 and 11 kV. There are also some energy intensive customers that are supplied via dedicated distribution feeders.

During the 2009-10 financial year a total of 4,695 GWh of energy was supplied to Aurora's distribution network; with 4,652 GWh of energy delivered from the transmission network and 43 GWh from distributed generation sites. The total distribution customers' aggregate consumption for the same period, as metered at the customer's point of supply, was 4,462 GWh.

The aggregate co-incident maximum distribution feeder demand for the 2009-10 financial year was 1,042 MW at 8:30am on 8 July 2009.

The HV distribution network is best characterised as a "rural, overhead" network. Most of Aurora's HV feeders and practically the entire LV network consists of overhead construction. Underground cable reticulation is restricted to central business districts and various subdivisions and commercial centres in urban or suburban areas. Aurora's rural distribution feeders tend to be lengthy, between 50 and 500 km, and of a radial nature with limited ability to interconnect with other adjacent rural distribution feeders. Urban distribution feeders, on the other hand, have a greater flexibility to provide alternate supplies to the majority of customers on a distribution feeder. Consequently outages on rural feeders generally have a greater impact upon reliability.

A brief overview of Aurora's distribution network assets are shown in Table 13.

Table 13

Aurora's distribution network

	As at 30 June 2010
Customer connections (total)	329,111
Residential connections	229,420
Non-residential connections *(Commercial / industrial)*	50,369
Unmetered connections	49,322
Overhead (km) – High Voltage	15,069
Underground (km) – High Voltage	1,077
Overhead (km) – Low Voltage	7,197
Underground (km) – Low Voltage	1,101
Poles	221,906
Distribution substations	31,287
Distribution feeders (total)	317
- CBD	24
- Urban / suburban	140
- Other (Rural)	153

4.5.2. Distribution feeders

The planning and management of Aurora's 317 distribution feeders occurs at a single planning level. This approach to planning allows for:

- better monitoring of supply reliability issues for each distribution feeder;
- an ability to focus on specific locations in each area, such as towns or suburbs; and
- appropriate management of performance against *TEC* standards.

Each of the distribution feeders has been classified into one of the categories for performance management and reporting. A brief overview of Aurora's HV distribution feeders are shown in Table 14.

Table 14

Aurora's distribution feeders

Feeder category	No. of feeders	Connected kVA	Overhead route length (km)	Underground route length (km)	Total route length (km)
CBD	24	284,565	15	82	97
Urban	140	1,206,548	1,260	545	1,805
Rural	153	2,030,908	13,894	366	14,260
Total	**317**	**3,522,021**	**15,169**	**933**	**16,102**

Not all of Aurora's HV distribution feeders have been included in Table 14.

Sub-transmission feeders supplying large distribution zone substations are excluded as they have no connected customers up to the zone substation. Customers are supplied through a further network of HV distribution feeders emanating from these zone substations.

Specific industrial feeders that supply individual points or bulk loads (i.e. dedicated large industrial customers) and ungrouped feeders are also excluded. The 'ungrouped' class includes those distribution feeders with no connected customers, future distribution feeders and substation internal supplies. A brief overview of Aurora's other HV feeders are shown in Table 15.

Table 15

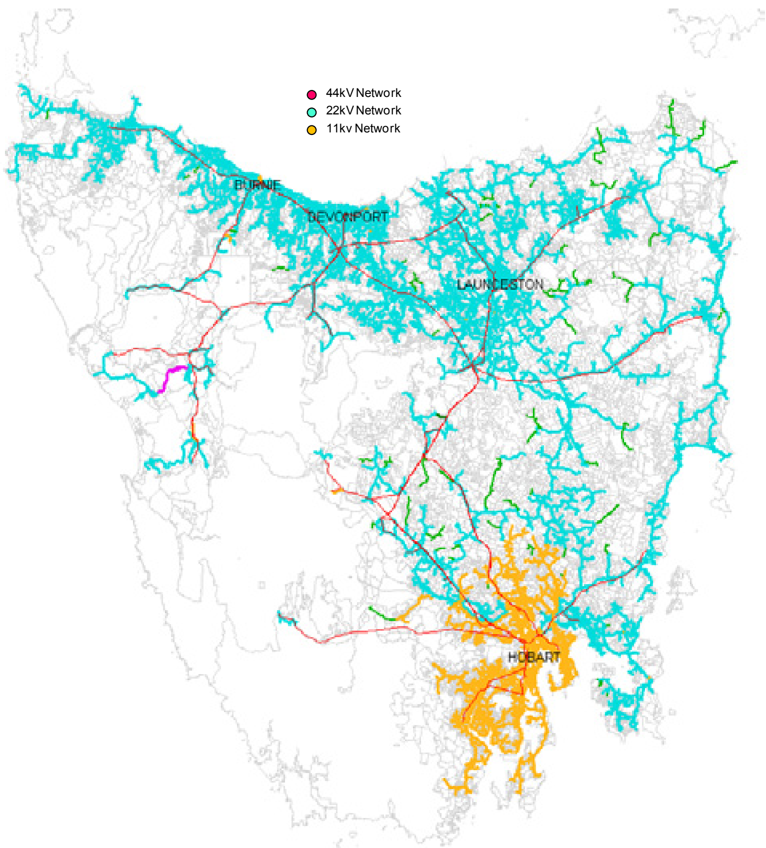
Aurora's other distribution feeders

Feeder category	No. of feeders	Connected kVA	Overhead route length (km)	Underground route length (km)	Total route length (km)
Industrial	21	121,628	127	39	166
Sub-transmission	20	963	112	42	152
Ungrouped	28	68,339	79	34	113

Figure 12 provides an overview of Aurora's distribution feeder network.

Figure 12

Aurora's distribution feeders



4.6. Supply side solutions are balanced with demand side management

There are two fundamental approaches to demand side management:

- to encourage users to move their load to a time when the network is being used less; or
- to encourage users to manage their demand so that, irrespective of time of use, network usage is better managed.

Ideally, both aspects of demand would be monitored and chargeable, to maximise Aurora's appropriate cost recovery from network users. The major factor surrounding the introduction of such controls is the metering technology that has, or may be, deployed. Aurora's metering strategy is to replace the current fleet of basic meters for general residential customers with a 'smart capability enabled', electronic meter that will have the ability for time of use metering, but not directly measured demand based charging. It follows, given the approach in the NEM, that time of use charging is the choice for small customers who qualify for Smart Meters, while demand charging, perhaps in conjunction with time of use charging, is appropriate for larger customers.

A number of demand side management schemes, currently employed or under trial within other jurisdictions, are being considered for implementation and/or trial by Aurora. Such schemes include:

- remote control of residential and commercial storage hot water;
- commercial air conditioner control management systems;
- energy purchase/buy-back or tariff incentive programs;
- targeted commercial demand side management and energy efficiency programs;
- residential demand response appliances; and
- education programs promoting energy efficiency.

Implementation of several demand side management schemes may be necessary to be an effective and viable alternative investment option to address network constraints or defer network augmentation due to the dispersed customer base within Aurora's distribution network, the daily electricity demand profile of the various customers and location factors with respect to the existing network.

4.7. Environmental challenges facing Aurora

Environmental challenges facing Aurora include:

- greenhouse gas emissions;
- biodiversity;
- fauna mitigation;
- oil management; and
- controlled waste.

New projects requiring design work are reviewed for environmental exposure and may be referred to an environmental consultant for further review. All new projects are assessed for their impact on Aboriginal heritage and clarified with the Aboriginal Heritage Tasmania section of Department of Primary Industries, Parks, Water and Environment (DPIPWE).

Further details of these challenges are set out below.

Greenhouse gas emissions

In Australia, the single biggest source of greenhouse gas emissions is the electricity (or stationary energy) sector. This means that the electricity sector has to make among the greatest changes to its operations to reduce its level of emissions.

Aurora also contributes to greenhouse gas emissions through the utilisation of its vehicle fleet.

Biodiversity

As Aurora's distribution assets are located throughout Tasmania, Aurora has a fauna strategy to protect the high biodiversity values that exist throughout Tasmania together with mapping and reporting in respect of its infrastructure to determine environmental impacts.

Fauna mitigation

Aurora works with the DPIPWE to mitigate injuries and interactions with threatened fauna species due to impact with or electrocution from Aurora's distribution network.

Oil management

Aurora's distribution network has many assets that are filled with oil, and as such, oil spills are a possible environmental risk.

Controlled waste

The chemical cleaning, storage, transport and disposal of Aurora's controlled waste intrastate and interstate requires it to comply with State regulations for those activities.

4.7.1. Short and long-term mitigation

Greenhouse gas emissions

Aurora utilises a Carbon Inventory Management System to track and report its greenhouse gas emissions[3]. It ensures Aurora is able to collate, track and manage its carbon footprint and provides Aurora with a strategic focus for managing and reducing its emissions.

Sulphur hexafluoride (SF_6) is one of the lesser known greenhouse gases that is used almost exclusively by the electricity industry. It is an extremely inert gas that suppresses arcs and Aurora uses it as an insulator in its switchgear. Aurora tracks and reports the volume of SF_6 and keeps a watching brief on technological developments that will allow Aurora to phase out its use.

Aurora's second largest source of direct emissions is its fleet of operational vehicles, with over 6,000 tonnes of emissions[4].

3 Ibid. page 62.
4 Ibid. page 62.

An active fleet incorporating a range of different types of vehicles is integral to Aurora's various business operations. Fleet however, is an area where Aurora can improve its performance. Aurora has changed its pattern of vehicle procurement to more environmentally friendly models and the next challenge is to influence vehicle use and driver behaviour.

Biodiversity

Aurora utilise the Natural Values Atlas (NVA)[5], Aurora's geospatial information system (GIS) and its fauna strategy to protect the high biodiversity values that exist throughout Tasmania. The NVA is a comprehensive database and reporting system developed by DPIPWE, while the GIS is a mapping system of Aurora's infrastructure that overlays other mappings systems to determine environmental impacts.

These environmental tools enable Aurora's designer/estimators to map infrastructure routes well clear of conservation areas and threatened environmental species and in doing so ensure that Aurora complies with environmental legislation.

The NVA is also used as a guide to best-practice vegetation management around the distribution assets. It provides information on the best method of vegetation removal and helps Aurora to minimise its environmental footprint. For example, Aurora ensures that a vegetative cover is left on easements during overhead line construction to maintain native species habitats and avoid land management issues such as erosion.

Fauna mitigation

Aurora operates under a Public Authority Management Agreement (PAMA) with DPIPWE[6]. This agreement references the *Threatened Species Protection Act 1995* to enable both parties to work together to mitigate injuries to threatened fauna species (particularly birds of prey such as wedge-tailed eagles and grey goshawks) as a result of contact with the overhead distribution system.

All endangered bird death incidents are reported to DPIPWE and reviewed, with mitigation measures implemented where possible.

Aurora's fauna strategy requires an upgrade of old infrastructure to mitigate impacts on species such as wedge-tailed eagles. Aurora, in conjunction with the Threatened Species Unit of DPIPWE, has introduced a program to modify the steel lattice strain type of tower to make them safer for birds to land on.

Other line construction activities include fauna mitigation measures such as possum guards around power poles, bird 'flappers' on powerlines and minimising the impact on ground vegetation in order to protect habitat.

Oil management

Aurora's distribution network contains in excess of 30,000 oil-filled assets, and the management of oil spills is an important matter. All incidents involving a spill of insulating oil are reported to DPIPWE and rehabilitated by Aurora.

Aurora disposes of all PCB-free, oil-contaminated soil from oil spill clean-ups in the most sustainable way. All contaminated soil is sent to Port Latta for DPIPWE approved bio-remediation before disposal as landfill at the Port Latta Regional Landfill.

Controlled waste

Aurora is considered by the Environmental Protection Authority (EPA) within DPIPWE as a leader in the management and disposal of controlled wastes in Tasmania. There are no significant disposal sites for contaminated waste within Tasmania and Aurora is generally required to ship its controlled wastes interstate for disposal. Aurora's disposal regime includes:

- PCB-contaminated assets are sent to Victoria for chemical cleaning before disposal;
- non-scheduled PCB-contaminated oil is sent to Victoria for blending and disposal in Queensland;
- scheduled PCB-contaminated capacitors are sent to Queensland for disposal;
- drums of oil compound are disposed of interstate;
- chemical cleaning of PCB contaminated bulk tanks and large regulators is performed by interstate contractors in a controlled area under permit from the EPA; and
- waste PCB-free oil is disposed of at Mole Creek in Tasmania.

Environmental impact assessments, including aboriginal heritage

When planning projects, Aurora utilises environmental impact assessments to help it identify potential positive or negative impacts on the natural, social, or economic environment.

Aurora has initiated and implemented plans to mitigate major environment impacts. These plans include:

- more effective containment of oil and oil-filled assets at the Cambridge and Rocherlea oil facilities and the transformer storage area at Cambridge;
- the implementation of a chemical management system (Chemgold 3) to manage legislative requirements for the availability of material safety data sheets for chemicals, and the analysis of chemicals for risk assessment and segregation[7];
- the training of designer/estimators to Certificate IV in Environmental Management[8];
- the enhancement of the GIS to include environmentally sensitive areas such as raptor nesting sites, vegetation types, private reserves, conservation sites, Phytophthora cinnamomi sites, Ramsar wetlands and World Heritage Areas[9]; and
- a tender/contract assessment tool for review and analysis of contractors' environmental systems and environmental capabilities.

5 Ibid. page 60.
6 Ibid. page 60.
7 Ibid. page 58.
8 Ibid. page 59.
9 Ibid. page 59.

4.8. Aurora's commitment to new technologies

Smarter network technology

Aurora has adopted a strategy that enhances its focus on customer outcomes and utilises smarter network technology in the belief that intelligent networks and smarter grids are the future of distribution businesses.

Aurora's smarter network vision is for a resilient distribution network that delivers low-cost, sustainable energy to an engaged and knowledgeable customer base. It uses advanced metering infrastructure, demand response programs and home energy management systems to provide customers with an ability to better understand and manage their consumption and to produce their own energy.

A trial of smarter grid technology that allows the customer to test demand side management and retrieve live information about their electricity consumption will be implemented. Communication in the field will also be enhanced with the trial of electronic work dispatching.

4.9. Factors affecting network management

Residential load growth

The factors considered for residential load growth in Tasmania include:

- overall population growth; and
- areas of high customer growth.

The Australian Bureau of Statistics (ABS) forecasted overall population growth estimates for Tasmania are reported as being flat in the medium to long-term, and in some areas these estimates are believed to be negative. However, those estimates have been offset by the growth of the number of occupied dwellings and new building approvals.

Aurora's load data shows high customer load growth in the Hobart (eastern and northern suburbs), southern (Kingston), Tamar west (Launceston) and East Coast areas of the State. This is also substantiated through the number of modifications to existing and new customer connections being established within these areas.

Commercial and industrial load growth

The commercial and industrial growth is driven mainly by parameters affecting the Australian economic outlook rather than local Tasmanian economic parameters, as the markets for these industries tends to be into other parts of Australia and overseas. This group of customers has strong negative pressures caused by the estimates of relatively flat or reduced population growth over the forecast period that leads to a constrained or smaller market.

Demand

Ability of the distribution system to cope with a greater maximum demand

The Tasmanian electricity system normally reaches a coincident maximum demand (CMD) peak in either July or August each year[10].

There are numbers of factors influencing CMD:

- climate change;
- energy efficiency (State and national programs);
- energy usage price signals; and
- energy sources (renewable-distribution/home generation)

State-wide load and consumption forecast growth rates have been determined using three growth scenarios:

- low;
- medium or expected; and
- high.

Medium growth forecasts are adopted for distribution network assessment and planning. High and low values of growth are used to assess the level of variability and risk.

The load forecasting process will identify areas where load growth rates warrant investigation. The growth rates experienced in those areas will impact on network system capability and highlight potential or existing network capacity constraints over the next 10 years.

In order to understand the impact of these load growths and where augmentation projects may be necessary, the load forecasting outcomes are recognised and reported at a:

- system or state-wide distribution network level;
- terminal substation and upstream network connection point; and
- regional and area level.

Weather

There has been a notable increase in the number of significant weather-related events involving severe winds and/or lightning that have affected Aurora's distribution infrastructure. Typically these events have affected approximately 10,000 or more customers with resultant power failures. The majority of these outages are caused by trees and associated vegetation, outside Aurora's clearance zones, falling across powerlines; and lightning strikes on or near electrical assets causing fuses to blow and transformers to fail. Power is generally restored to the vast majority of the customers within 12 hours.

The most significant recent weather-related event was a severe windstorm that crossed the north-west and north of the State on the morning of Sunday, 27 September 2009, affecting approximately 45,000 customers. Trees in areas inland from Wynyard to Deloraine brought down powerlines and poles, destroyed transformers and blocked road access. In some cases it took three to four days before affected areas could be accessed and cleared. It was almost a week before restoration was completed.

10 Aurora Energy Pty Ltd, *Introduction of Time of Use and Specified Demand Network Tariff Charging Components - Issues Paper – December 2008.*

Aurora's Fault Centre struggled to cope with call volumes with as many as 60,000 calls on the first day. A trouble analysis function in the Fault Centre's outage management system was introduced in August 2010 and is designed to give the system the ability to interpret the most likely cause and location of system failure from the customers' calls. It is expected that this function will speed restoration times.

4.10. Network reliability

Aurora's network reliability performance for the current and previous *Regulatory Control Periods* is shown in the following figures. In trend terms the performance has shown a slight improvement over this term.

Figure 13

Overall distribution SAIFI

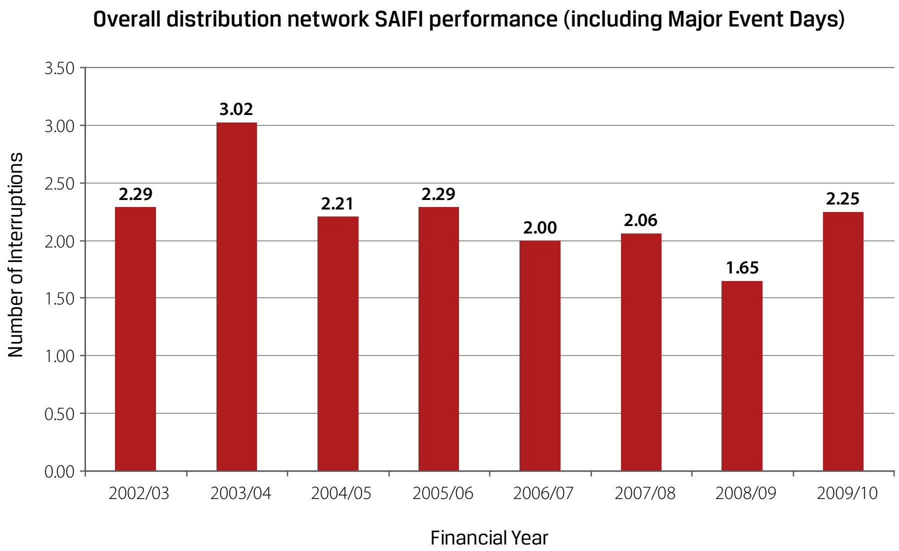
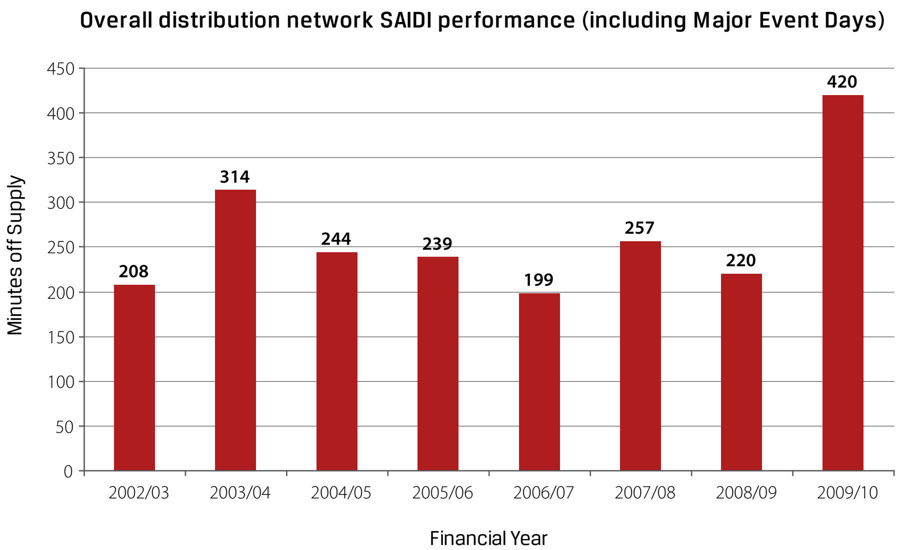


Figure 14

Overall distribution SAIDI



The removal of Major Event Days from reliability data is commonly used to provide an indication of the underlying performance of the distribution network under "normal" operating conditions.

A Major Event Day (MED) for Aurora is a day in which the SAIDI exceeds a threshold set in accordance with a methodology determined by OTTER. Using this method the MED exclusive (normalised) performance is shown in the following figures.

Figure 15

Normalised distribution SAIFI

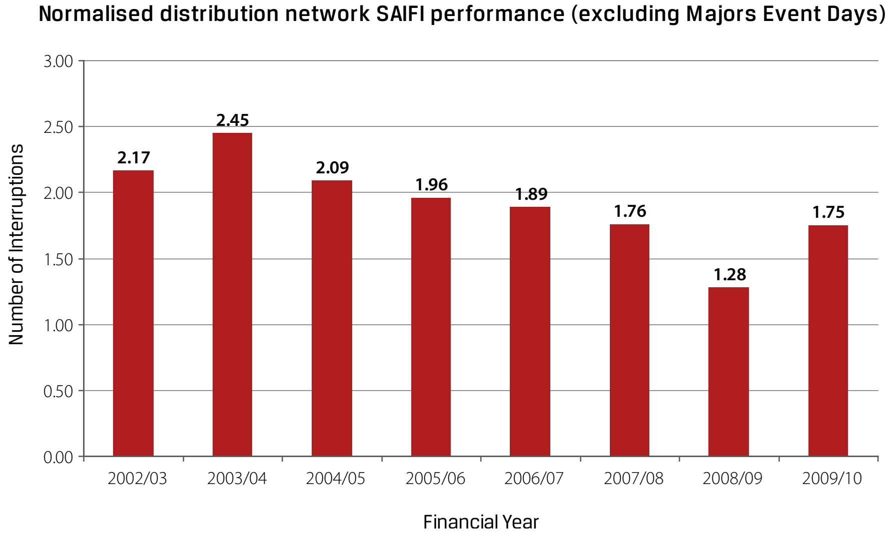
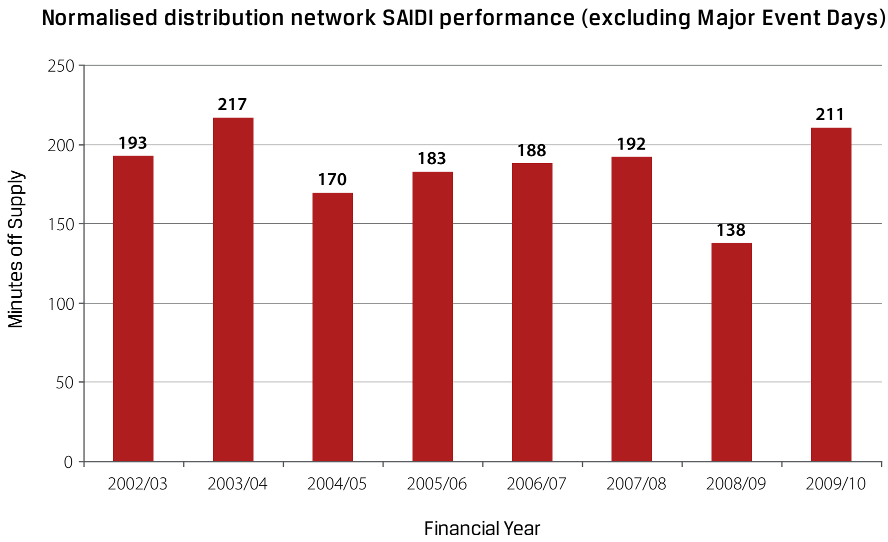


Figure 16

Normalised distribution SAIDI



4.11. Maintenance areas

Aurora has divided the State into 19 individual maintenance areas to provide a more focused and targeted approach to the management of the distribution system. This approach ensures better reporting on actual performance to specific customers and interested parties. Dividing the State into 19 areas allows for better understanding of the risks and influences in specific areas and provides a focused approach to problem solving. These areas are shown in Figure 17.

Figure 17

Maintenance areas

4.12. Depots

Field crews (resources) that undertake work and, more importantly, fault and emergency activities are located at sites around Tasmania.

There are four major resource centres located at:

- Cambridge on the eastern outskirts of Hobart;
- Rocherlea on the outskirts of Launceston;
- Devonport; and
- Burnie.

These resource centres are supported by eight response centres (excluding King and Flinders Islands) providing fault responses as well as day-to-day distribution service activities.

The maintenance areas serviced by these depots are shown in Table 16.

Table 16

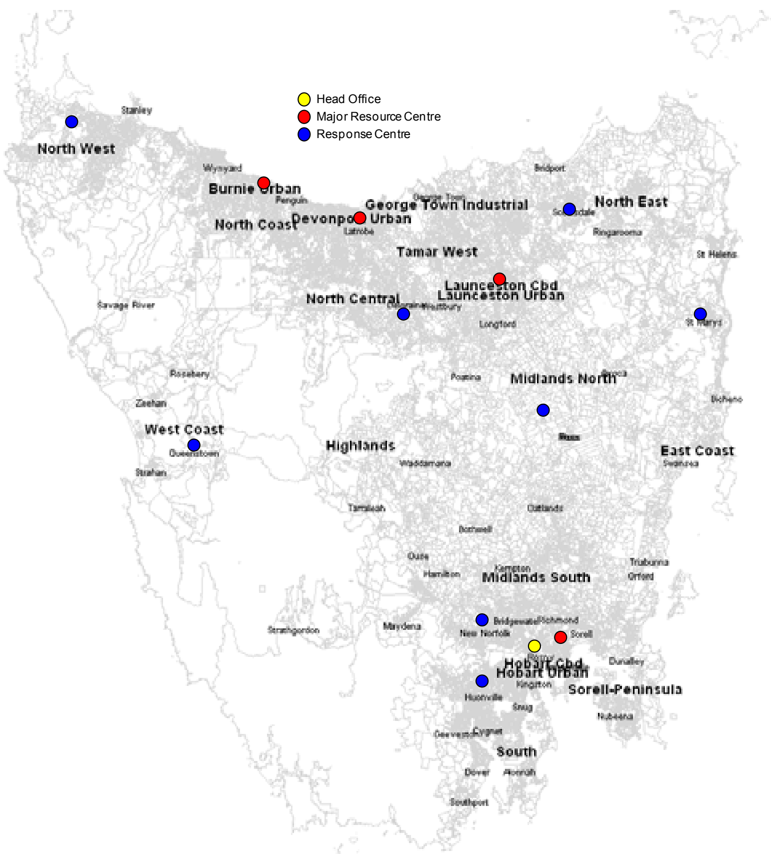
Aurora's depots

Resource/ Response Centre	Maintenance Area
Burnie	Burnie, North Coast
Cambridge	Hobart, Midlands South, Sorell Peninsular, East Coast
Campbell Town	Midlands North, East Coast, Midlands South
Deloraine	North Central, Midlands North
Devonport	North Coast, North Central, Devonport
Huonville	South
New Norfolk	Midlands South, Highlands
Queenstown	West Coast
Rocherlea	Launceston, North East, Tamar West, Midlands North
Scottsdale	North East
Smithton	North West
St Marys	East Coast, Midlands North

The location of Aurora's resource and response centres are shown in Figure 18.

Figure 18

Aurora's depots



4.13. Planning areas

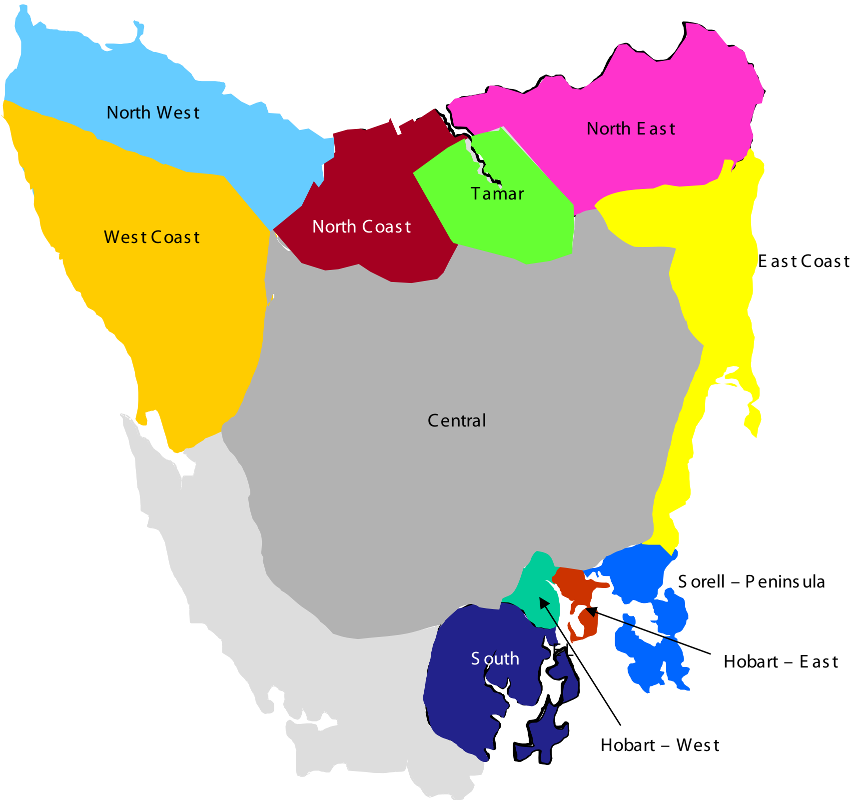
Aurora has divided the State into 10 individual planning areas to ensure efficient planning and focused management of the distribution system. These planning areas are shown in Figure 19.

These planning areas are based upon:

- the location of major substations;
- the supply area footprint;
- mutual support for HV transfer and capability;
- the routes of HV feeders;
- reliability of supply;
- similar demographics and industry; and
- population centres.

Figure 19

Planning areas



The nature and characteristics of each of Aurora's planning areas is discussed below.

4.13.1. Central area

The Central planning area is characterised by low customer density requiring Aurora to provide a widespread rural system to service its customers. In general terms the individual substations within the area have power transformers typically 5 MVA and below. The area has rugged terrain, which is frequently inaccessible during winter storms. This area has required significant investment in substations and general infrastructure to meet the capacity and reliability requirements. Currently, the general highlands area has small loads but contains significant tourist and economic industries, for example a fingerling hatchery at Wayatinah.

The growth for this area is now generally low and as such requires little investment to meet capacity criteria. Ongoing management issues in this area are system reliability and security.

4.13.2. East Coast area

The East Coast planning area is characterised by low customer density with a diverse customer base requiring a widespread rural system to service its customers. The area has a large coastal terrain, posing challenges to reliability during wind and sea storms. It is the centre for relaxed living, and as such has seen an increase in residential development; mainly weekend cottages, along with robust tourism, fishing, farming and viticulture industries; especially in the East Coast town of St Helens.

4.13.3. Hobart area

The Hobart planning area encompasses areas both sides of the Derwent River; from Lower Taroona and South Arm, to Bridgewater in the north, and has a mixture of commercial, industrial and residential customers.

The area has localised issues of system security and capacity and localised high load growths. Being an 11 kV supply network has resulted in reliability, whilst sub-optimal in some areas, that is generally good due to the short high voltage feeders that are typical with 11 kV networks.

To better manage the Hobart area, it has been split into two planning areas:

- Hobart - East; and
- Hobart - West.

4.13.4. North Coast area

The North Coast planning area is characterised by residential and commercial coastal strip development with an inland customer base, supporting farming activities. The area contains the city of Devonport and a number of significant towns and hamlets involved in the tourist industry. The Cradle Mountain tourism area also lies within this planning area.

The difficult topography of the area limits the nature and style of the construction of the distribution network; long river valleys create planning issues, and the connection ties to the lateral feeders and high voltage feeders are difficult.

Whilst weather is generally mild, significant storms accompanied by extreme wind events occur from time to time.

The area generally has low load growth, with the substations supplying the area being well loaded, but of no concern. Significant issues in this area are localised bubble developments such as Port Sorell. These developments cause significant problems with the distribution HV network, but not to the substations supplying that network.

4.13.5. North West area

The North West planning area is similar to that of the North Coast area. It is characterised by residential and commercial coastal strip development and an inland farming base. The area includes the city of Burnie and a number of large towns supporting a rural and tourism industry base.

The difficult topography of the area limits the nature and style of the construction of the distribution network. Long river valleys create planning issues, and the connection ties to the lateral feeders and HV feeders are difficult. The weather is more often quite severe, with significant storms accompanied by extreme wind events.

The area has generally had a moderate to strong load growth with the commercial heart of Burnie demonstrating a consistent load growth. Burnie is unique in that it has a commercial district supplied at 11 kV from Emu Bay substation, and the rest of the coast and inland supplied at 22 kV. This poses a number of challenges to Aurora surrounding security of supply for the Burnie commercial area.

The area has a high penetration of alternative gas energy source and there are a number of major customers implementing co-generation. There have been a number of enquiries from these customers to provide support services to the distribution network.

4.13.6. North East area

The North East planning area is characterised by farming, commercial and tourism developments, and strong viticulture activities.

The far Northeast is mainly rural. It has very low density; to the extent that is served by a number of SWER distribution systems, this hampers flexibility and development in that area.

The area has moderate load growth with the substations supplying the area being recently refurbished. Both are well loaded but are not causing concern.

4.13.7. South area

The South planning area is characterised by strong urban development interspersed with light farming and forestry activities. The lower south area has become a hub for tourism activities.

The whole area has seen consistent growth over a number of years and represents one of the fastest growing areas both in electricity demand, and also new housing subdivision developments. The northern component (Kingston region) of this area has become a commuter suburb of Hobart.

The Kingston region, including Blackmans Bay, Margate and Electrona, continues to be one of the regions with significant forecasted load growth. This load growth has primarily been as a result of high volumes of residential and commercial developments being established in those areas.

The Kingston region is the fastest growing residential area in Tasmania.

4.13.8. Sorell – Peninsula area

The Sorell – Peninsula planning area is characterised by a mixture of strong urban development in and around the beaches of Frederick Henry Bay. Areas of the Forestier and Tasman Peninsulas have a number of hamlets with strong tourism and fishing industries.

As the Sorell distribution voltage is 22 kV, it cannot interact easily with the Hobart East area which has a system voltage of 11 kV. This poses issues with transfer capacity in the Sorell Township, Midway Point and Richmond areas.

4.13.9. Tamar area

The Tamar planning area comprises Launceston City with a large commercial and urban base, George Town with a large industrial base, and the areas south and west of Launceston with a mix of heritage, urban and increasing industrial developments.

Continued load growth in the Launceston CBD and surrounding areas, aided by the Woodheater Replacement Program[11] and similar heating conversions, still continue to put pressure on the capability

11 Launceston City Council, *Woodheater Replacement Program.*

of the distribution network to provide sufficient capacity in both the HV and LV networks in this area. Further, medium to long-term load growths see an increasing loading on the existing Transend substations within Launceston.

The establishment of two connection points of Hadspen and Mowbray substations has helped to relieve the constraints of the very heavily loaded Trevallyn and Norwood substations. These two new substations are now over or near firm capacity also. Even with these substations, the Launceston area has seen consistent growth that cannot easily be met by the distribution system or the Transend substations.

The industrial area of Westbury to the west and commercial areas of Launceston Airport to the south are also showing signs of system stress from capacity constraints.

The agricultural area around Palmerston substation has a strong irrigation presence, which sees this area peaking in the warmer months.

4.13.10. West Coast area

The West Coast planning area has a very strong association with the mining industry. With the exception of Strahan Village, most communities either work in the mining industry or are allied to fields supporting this industry. As such the planning area sees periods of strong growth followed by times of inertia.

The area has developed a viable tourism industry based upon mining and the area's untouched wildernesses resources.

The electrical network at Rosebery substation has an unusual voltage arrangement. The output voltage at Rosebery is at 44 kV, which is the only substation at that voltage in Tasmania.

4.14. Forecast augmentations

4.14.1. Central area

The identified or known large constraints are as follows:

- Gretna, New Norfolk, and Westerway zone substations have transformers in severely deteriorated condition. Transformers range from 1.0 to 2.5 MVA in size. Further in these areas the supply voltage is a mix of both 11 and 22 kV. This mix of circuits and voltages presents ongoing operational problems of loadings and system and emergency management.
- The areas around Kempton and Melton Mowbray have overloaded feeders and acknowledged high voltage power quality problems along with some reliability issues. In general this area has significant potential for irrigation, e.g. Clyde irrigation project; and as a consequence high use of electric water pumping. This network voltage is 11 kV, which is particularly intolerant to large motor starting which gives rise to ongoing power quality issues.

To address the above constraints the following is proposed:

- Gretna and Westerway zone substations 11 kV circuits will be progressively augmented to 22 kV thereby eliminating the need for zone substations. This is planned to continue to 2017.
- The areas of Melton Mowbray and north of Kempton will be progressively augmented from 11 kV to 22 kV and transferred to Meadowbank supply. The first stage, new connection at 22 kV near Bothwell, is complete with further stages to be considered within the 2011-15 years.

4.14.2. East Coast area

There are no identified issues within this area.

4.14.3. Hobart area

Hobart East

Most of the issues relating to the Hobart East area are associated with high voltage capacity or security constraints. The constraints identified within the area are:

- Geilston Bay zone substation is non-firm during the winter months;
- Geilston Bay zone substation transformers are deemed end of life in 2018;
- Geilston Bay zone substation has 2 HV feeders peaking over their planning rating;
- Bellerive zone substation is non-firm during the winter months;
- Bellerive zone substation transformers are deemed end of life in 2020;
- both Bellerive zone substation 33 kV sub-transmission cables are derated due to one oil-filled cable section on each sub-transmission cable being installed in long under road crossings;
- Bellerive zone substation has 23 HV feeders peaking over their planning rating; and
- oil tests have shown that both Richmond zone substation power transformers are in poor condition. A mixture of 22 kV and 11 kV distribution networks within the Richmond area limits distribution transfer capacity during planned outages and fault management.

To address the above constraints the following is proposed:

- following a final report submitted to AEMO covering a joint Aurora and Transend study, a significantly reinforced Eastern Shore 33 kV and substation and zone substation arrangement is proposed;
- Howrah and Rosny zone substations are to be established before winter 2012 and 2013 respectively;
- from 2017 and beyond it is envisaged that a new Sandford zone substation will be constructed. This will alleviate the existing 11 kV feeder constraints from Rokeby substation;
- one transformer is to be upgraded at Richmond zone substation in 2013. System security will be managed from the 11 kV network;
- in 2017 Richmond zone substation is to be upgraded from a 22/11 kV to a 33/11 kV zone substation supplied from Lindisfarne 33 kV substation;
- in 2018 and 2020 the Geilston Bay and Bellerive zone substation transformers will reach their nominated end of life. From these dates onwards it is possible that these transformers will be upgraded due to deterioration in their condition; and

- progressive work will be undertaken from 2011-18 to re-voltage both 11 kV and 22 kV circuits in the Richmond area to facilitate interconnection and standardising of supply.

Hobart West

Most of the issues having to be managed in the Hobart-West area are associated with capacity constraints, security and reliability. Further, there are a number of areas where localised high load growth is causing problems at the distribution substation level and associated low voltage network. The constraints identified within the area are:

- North Hobart 11 kV busbar loading imbalance causing voltage regulation issues in the supply area and four feeders are marginally over the planning rating;
- there are two feeders emanating from Sandy Bay zone substation over the planning rating. These feeders are supplying the University of Tasmania and Sandy Bay and Taroona residential areas;
- strong growth in the Chapel Street and Claremont supply area footprints. These areas are having a strong take-up of undeveloped land for new subdivisions. These areas represent the last undeveloped areas before the Bridgewater township; and
- the State Government initiated Brighton Transport Hub analysis has shown that the area will have a strong developing load base over the next two to 10 years. Development will include commercial, minor industrial and, as land becomes available, residential subdivisions.

To address the above constraints the following is proposed:

- North Hobart bus loading investigation is being undertaken. Likely options are the installation of capacitor banks on some feeders. It is expected that the work will be completed in 2011-12;
- a joint project between Aurora and the University of Tasmania is being proposed for 2012-13 to split the existing university single feeder ring supply using existing infrastructure;
- to manage the existing constrained feeders at Chapel Street and North Hobart prior to a Creek Road 110/11 kV substation, a new feeder from Chapel Street and additional feeder augmentations have been proposed between 2012-13 and 2015-16; and
- significant investment is being made in conjunction with the Brighton Transport Hub. Work was undertaken in 2009-10 with DIER for the relocation of existing infrastructure and in conjunction with these works the opportunity to develop a future 33 kV network serving a future substation north of Brighton has been taken.

4.14.4. North Coast area

The constraints identified within the area are:

- hot spot growth at Port Sorell and Hawley Beach. The existing feeder network has difficulty in supplying the area from Devonport substation to the east and from Railton substation to the north. One 22 kV distribution feeder emanating from Devonport substation supplies the rural area east of Devonport through to Port Sorell whilst the southern half is supplied from Railton substation; and
- inconsistent application of appropriate HV phase rotation design standards has resulted in many small distribution substations being unable to be paralleled on the low voltage side. This has sub-optimal outcomes of managing the low voltage networks at times of maintenance or localised fault activities.

To address the above constraints the following is being proposed:

- the commissioning of a 22 kV source, from Transend's Wesley Vale substation, will alleviate a number of distribution issues in the Wesley Vale and Port Sorell areas. The availability of a 22 kV source has come about due to the major Transend customer not wishing to take supply beyond 2010. This has enabled reuse of the Wesley Vale substation to serve 22 kV Aurora load; and
- there is to be a multistage project up to 2015-16 to correct high voltage phasing problems in the Devonport region. This will allow the use of adjacent substations to support customers in time of maintenance and fault conditions.

4.14.5. North West area

The constraints identified within the area are:

- Burnie substation has two feeders exceeding the planning rating. These feeders supply the areas west of Burnie including Wynyard;
- Ulverstone substation has two feeders exceeding the planning rating;
- Emu Bay substation will see three of its four feeders approaching their planning rating in five years;
- Burnie CBD is supplied at 11 kV and has no support from Burnie substation (22 kV); and
- transfer capability to the area of Wynyard, Somerset and areas west of Burnie is very limited. Of the four feeders supplying this area two are overloaded and the remaining two will exceed the planning rating in five years.

To address the above constraints the following is proposed:

- the existing supply point at Emu Bay substation is an 11 kV connection and is incompatible with the surrounding area voltage (22 kV). The 11 kV supplies only the Burnie CBD. With the major customer at Emu Bay substation ceasing operations in 2010 conversion of the substation from 11 to 22 kV is being evaluated. The overall project will become a joint planning study with Transend to identify options; and
- the deferment of the Wynyard substation to 2017 may see the need for a further extensive 22 kV feeder augmentation program to manage the existing and future constraints. Demand side management activities are actively being considered. This work would address firm capacity issues at Burnie and Ulverstone substations and improve supply to the Wynyard area.

4.14.6. North East area

The constraints identified within the area are:

- the SWER systems supplying Pipers River (Blessington) are overloaded;
- the SWER system that supplies Musselroe Bay is approaching its maximum load rating;

- the SWER system that supplies Reedy Marsh is approaching its maximum load rating;
- the SWER system supplying Mathinna is overloaded and has identified harmonic issues affecting the voltage in the SWER area; and
- the general reliability for the far North-east continues to be a concern.

To address the above constraints the following is proposed:

- staged augmentation of the Pipers River (Blessington) SWER system is continuing. The last stage is scheduled for completion in 2015-16;
- the staged augmentation of the Musselroe Bay SWER system has been placed on hold pending outcomes of a proposed commercial windfarm. However, should the commercial arrangement proceed, full augmentation will be required;
- the upgrade to the Mathinna SWER system is planned for 2012-13; and
- the installation of a second transformer at Derby substation to provide firm capacity at that substation.

4.14.7. South area

The constraints identified within the area are:

- Kingston substation has five feeders that exceed the planning rating. Load growth forecasts indicate that there will be another three feeders beyond the planning rating over the next five years. Collectively this represents eight of the twelve feeders being supplied from Kingston substation;
- load growth forecasts indicate that the Electrona substation will have two feeders beyond the planning rating over the next five years;
- load growth forecasts indicate that the Knights Road substation will have two feeders beyond the planning rating over the next five years;
- Huonville township, which is supplied from Knights Road substation, is also experiencing a number of large customers upgrading their supplies that will cause transfer and security issues at the 11 kV feeder level; and
- the Kingston commercial district has substandard power supply reliability.

To address the above constraints the following is proposed:

- a new 33 kV injection point and subsequent zone substations have been the subject of a joint planning study with Transend. A final report has been submitted to AEMO with the recommended option being to install a 110/33 kV substation and two zone substations at Kingston commercial area and Blackmans Bay;
- significant non-network solutions and a smarter grid trial are being undertaken in the Kingston supply area in 2011 and 2012 to reduce demand and defer the ultimate construction of the future Kingston zone substation;
- a Blackmans Bay zone substation is anticipated to be required by 2017; and
- Knights Road to Huonville augmentation and reconfiguration in Huonville is scheduled for 2015-16.

4.14.8. Sorell – Peninsula area

There are no identified issues within this area.

4.14.9. Tamar area

The constraints identified within the area are:

- Norwood substation has five feeders that exceed the planning rating. Load growth forecasts indicate that there will be another two feeders exceeding the planning rating in the next five years;
- load growth forecasts indicate that the Palmerston substation has a feeder that will exceed the planning rating in the next five years;
- Trevallyn substation has four feeders that exceed the planning rating. Load growth forecasts indicate that there will be another two feeders that will exceed the planning rating in the next five years;
- the present 22 kV system from Trevallyn also supports the second 22 kV transformer and busbar at Mowbray substation. Reliance is placed upon a 2 x 20 MVA direct 22 kV feeder link between Trevallyn and Mowbray substations. This link enables firm capacity at Mowbray substation. This issue cannot be successfully addressed until the second 110 kV line is made available to Mowbray substation in about 2012;
- strong industrial growth in the Westbury area is causing capacity problems managing new large commercial and industrial loads;
- strong commercial growth in the area of Launceston airport is causing capacity problems with the proposed new loads;
- security and transfer capability at Trevallyn, Mowbray, Norwood and Hadspen substations; and
- reliability to the Lilydale and Golconda areas north east of Launceston is of concern.

To address the above constraints the following is proposed:

- the installation of a 110/22 kV substation at St Leonards in 2012, to manage load growth and supply constraints;
- the installation of a new Westbury substation in 2017;
- the installation of a new Longford substation in 2021;
- the installation of a new East Launceston substation in 2027; and
- the installation of a new feeder from Mowbray substation in 2013-14 to manage load and reliability in the Lilydale and Golconda area.

4.14.10 West Coast area

There are no identified issues within this area.

4.15. Aurora's customer profiles

Aurora's commitment to maintaining value for customers

The price of electricity remains of great concern to Aurora's customers: in 2009-10, retail energy prices increased well ahead of inflation across Australia, and Tasmanian customers were not immune to this trend.

The corporate image survey conducted in May 2010 made it clear that Aurora needs to do more to explain to customers, especially the residential customers, how its prices are determined and what they comprise[12].

Aurora has recently finalised a strategy for the distribution business which promises improvements that will assist Aurora in delivering excellent service at the lowest possible price for customers. As distribution costs make up approximately 35 percent of electricity bills, the strategy aims to reduce operating and capital expenditure and therefore electricity prices through a greater emphasis on technical capabilities together with operational improvements.

The distribution strategy will also focus on empowering the customer through choice and ensuring that the delivery of energy to the customer meets expectations and caters for lifestyle demands in a problem-free and sustainable way. This will be achieved through a focus on innovation and the deployment of modern technology, improving the efficiency of Aurora's capital and operating expenditure to deliver efficient, sustainable customer focused outcomes and solutions.

Classes of network users

As the transmission network within Tasmania provides voltages to a level of 110 kV there is little or no requirement for heavy industries to seek connection to the Aurora distribution network. Aurora therefore has three predominant types of customers connected to its distribution network. These are residential, commercial/industrial and unmetered supplies. At the completion of the 2009-10 financial year there were 329,111 connections to the distribution network and these customers consumed 4,462 GWh. The number and consumption for these connections is detailed in Table 17.

Table 17

Distribution connections

Customer Type	Number	Consumption (GWh)
Residential	229,420	2,106
Commercial/Industrial	50,369	2,316
Unmetered	49,322	40

Residential

Aurora's residential customers are defined as those customers who occupy private residential dwellings; but do not include tourist or hostel accommodation or any commercial premises. Whilst these customers comprise approximately 70 percent of Aurora's connections they only represent approximately 47 percent of the energy consumption within the distribution network.

There are three general tariffs available to these customers in the form of general light and power; hot water (including space heating); and off-peak. These are three separate tariffs and the vast majority of customers take supply via the combined general light and power and hot water/space heating tariffs.

Approximately 40,000 or 17 percent of these residential customers take their supply via Aurora Retail's prepayment or PAYG product.

Commercial/industrial

Commercial/industrial customers are represented by:

- small to medium businesses (businesses that typically consume up to 750 MWh per site per annum), and include offices, shops, workshops used for retail purposes or other business activities; and
- large businesses or enterprises, which are commercial and industrial businesses that consume over 750 MWh of electricity per site per annum.

Commercial customers also include agribusinesses and those that have the sole intention of providing irrigation services.

An agribusiness is defined as a business used for farm operations and includes a business that engages in horticulture; dairy; keeping or breeding stock; growing fruit, vegetable, grain or other produce; or handling and packing of these products. It excludes a business that processes or retails farm products and also excludes businesses that engage in intensive animal husbandry, forestry, aquaculture or garden centre operations.

There are a variety of energy only or energy/demand tariffs at both low and high voltage available for these customers.

Agribusiness customers often utilise an unmetered supply for electric fences, and also take advantage of a specific irrigation tariff for large pumps that can be used for crop watering during the dryer summer months.

Whilst commercial/industrial customers comprise approximately 15 percent of Aurora's connections they represent approximately 52 percent of the energy consumption within the distribution network.

Unmetered supplies

Unmetered supplies comprise small connections such as electric fences, public telephone boxes, traffic signals and public lights. Whilst relatively high in number, approximately 15 percent of the connections, they represent less than 1 percent of the distribution network consumption.

12 Ibid. page 45.

The total customer tariff by NMI is shown in Table 18.

Table 18

Tariff numbers

Tariff	Description	Total
AURESGEN	General Network - Residential	184,895
AUBLVGEN	General Network - Business	38,446
AUBLVNURSE	General Network - Business, Nursing Homes	130
AUBLVCURT	General Network - Business, Curtilage	11,409
AUBLVDMKW	LV kW Demand	310
AUHEATUNCO	Uncontrolled Energy	174,042
AUHEATCONT	Controlled Energy	30,634
AUHEATCONN	Controlled Energy	2
AUIRRIG	LV Day/Night Irrigation	3,470
AUIRRIGTOU	LV Irrigation (TOU)	50
AUBLVDMKVA	LV kVA Demand	686
AUBHVDMKVA	HV kVA Demand	77
AUHVSPECDM	HV KVA Specified Demand	3
AUBHVDMKW	HV kW Demand	11
AUPAYG	LV PAYG	40,950
AUBUSTOU	LV ToU - Business	650
AURESTOU	LV ToU - Residential	1
AUCHVDM2	HV kVA Specified Demand (> 2.0MVA)	18
	Total	**485,784**

Contestable customers

Over time the State Government has introduced retail contestability to certain customers within the Tasmanian jurisdiction by means of tranches of contestability. These tranches have been determined in accordance with the *Electricity Supply Industry (Contestable Customer) Regulations 2005*. These Regulations are presently under review with the aim of introducing a further tranche of contestability to commercial customers consuming greater than 50 MWh per annum. The number of Aurora's customers that are (or will be) contestable is shown in Table 19.

Table 19

Contestable customers

Tranche	Annual consumption	Approximate annual spend	Date contestability introduced	Number	Types of customers
1	≥20,000 MWh	>$2,000,000	1 Jul 2006	19	Mineral processors / heavy manufacturing plants
2	≥4,000 MWh	>$400,000	1 Jul 2007	46	Food processing plants and multi storey office complexes
3	≥750 MWh	>$80,000	1 Jul 2008	330	Supermarkets, engineering workshops, smaller commercial complexes
4	≥150 MWh	>$25,000	1 Jul 2009	1,660	Fast food restaurants, service stations, large offices
5a *	≥50 MWh	>$10,000	1 Jul 2011	3,460	Small business customers

* Tranche 5a is yet to be approved by the State Government. It is anticipated that this tranche of contestability will commence on 1 July 2011 and be open to those commercial customers with consumption greater than 50 MWh per annum.

4.16. Aurora's demand profile

4.16.1. Peak demand

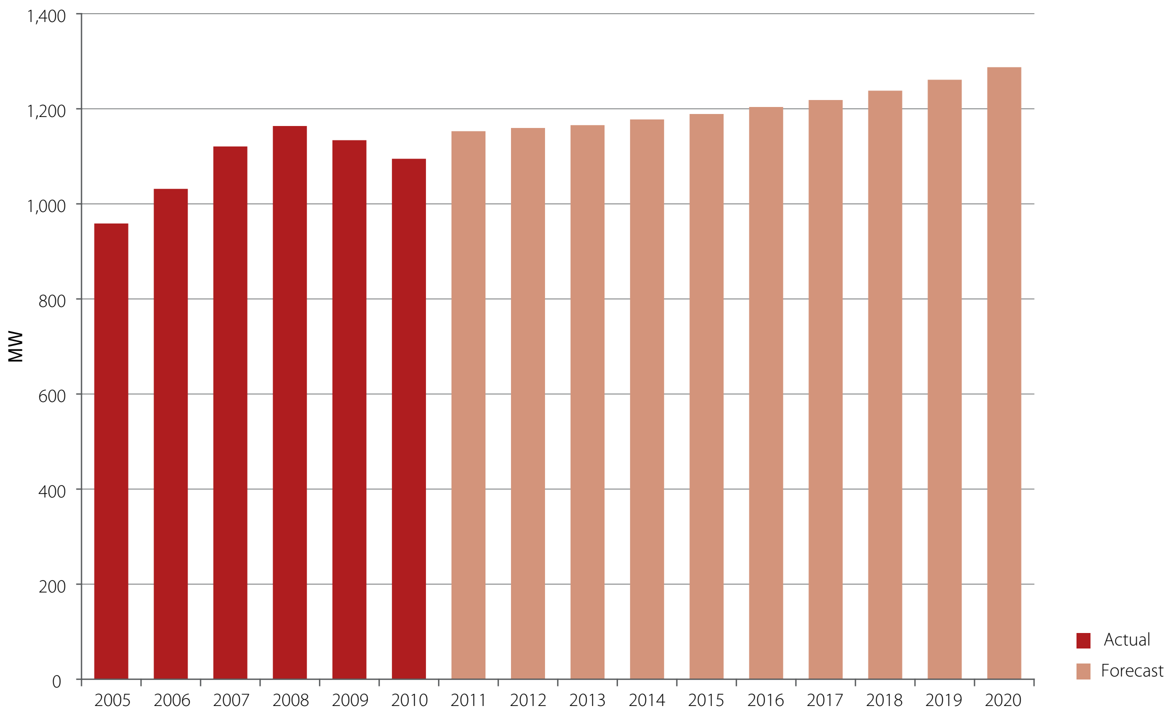
Peak demand on Aurora's network has historically occurred in the winter quarter with a strong inverse correlation to the maximum daily temperature at the time of peak demand. That is, demand increases as temperature decreases.

The underlying drivers of peak demand on the distribution network drive the need for network infrastructure investment.

Peak demand of 1,022 MW on the distribution network occurred on Thursday, 8 July 2010 at 8:30 am. This occurred on a day where the maximum daily temperature was higher (milder) than the long-term average. Using the temperature sensitivity coefficient for each connection point to adjust to the long-run average temperature, the temperature-corrected peak demand was 1,095 MW. Continuation in demand growth based on historical trends and State econometric forecasts is presented in Figure 20.

Figure 20

Temperature-corrected system coincident maximum demand

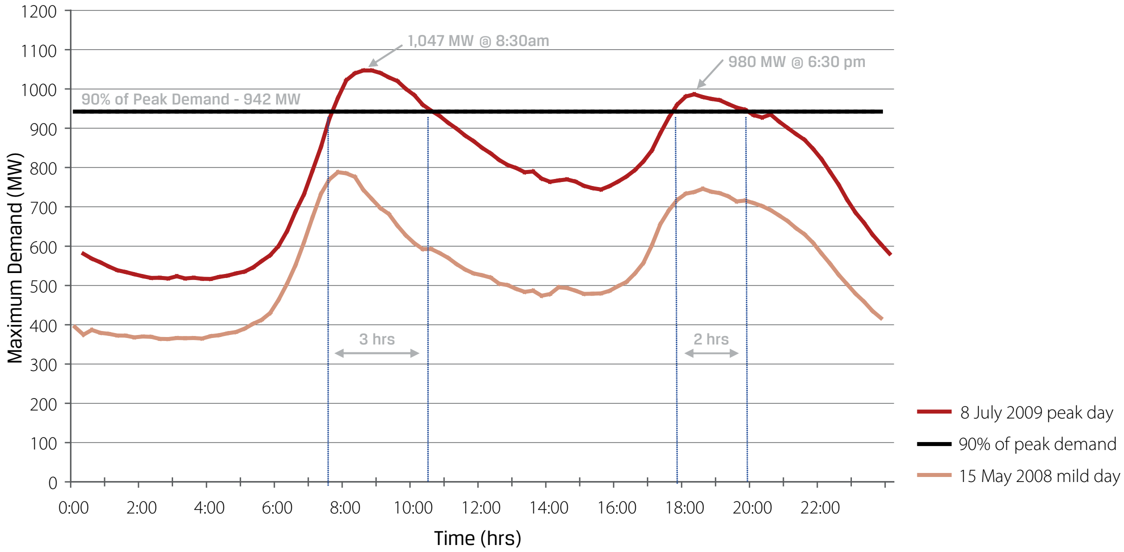


4.16.2. Load profile

Figure 21 compares the load profile of the 2009 total Aurora distribution network system peak day with a mild autumn weekday (15 May 2008). It shows that at the time of maximum system peak demand, the load on the system was some 250 MW higher than the load of a typical non-heating day. Most of this increase is attributed to temperature sensitive space heating load in the residential and business sectors.

Figure 21

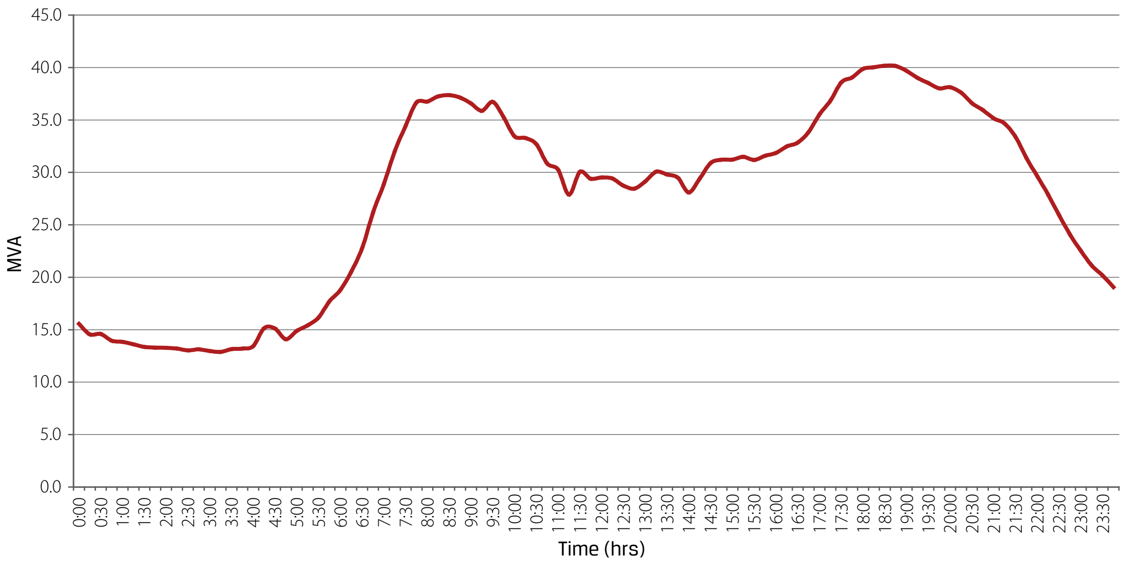
Aurora total system day load profile



A load profile for day of peak demand for the distribution network load on Transend's Kingston substation is presented in Figure 22. The composition of load connected to this substation is typical of many of the Aurora distribution network connection sites connected to the transmission network.

Figure 22

Load profile for Kingston substation



4.16.3. Load duration

The ratio of average demand divided by the peak demand for winter is 0.64, whereas that for summer peak is 0.68. For the winter peak approximately 10 percent (100 MW) of the peak demand occurs for only 66 hours of the winter quarter, representing less than 0.8 percent of the year.

Figure 23 presents the results of a load duration analysis of the distribution network for the winter period (1 June – 31 August) of 2009. The analysis indicates that the top 100 MW (or 10 percent) of the distribution network capacity was utilised for 66 hours (or less than 1 percent of the time).

Figure 23

Load duration winter 2009

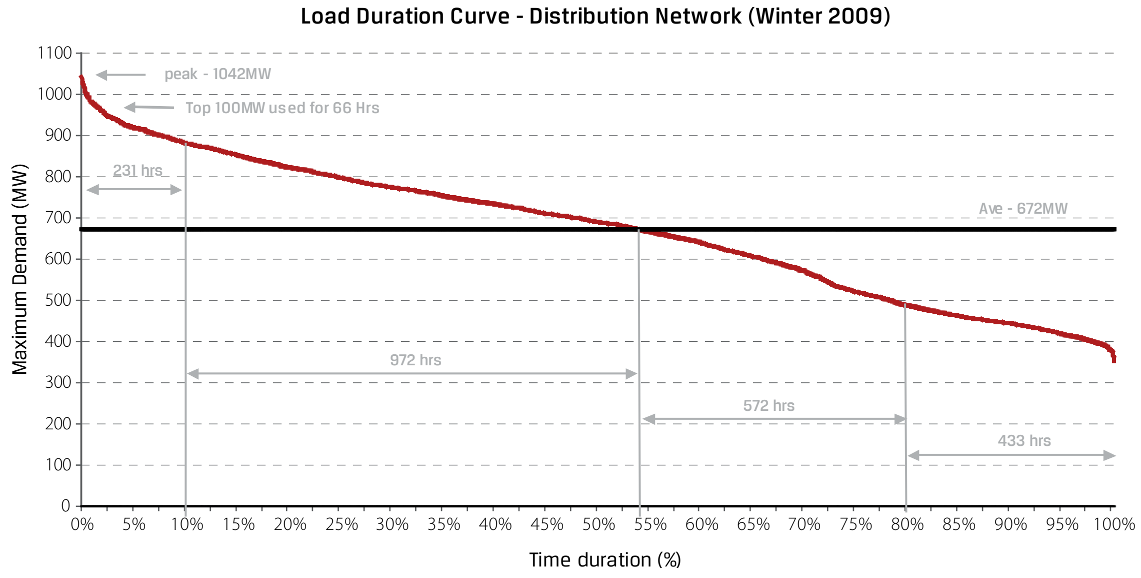
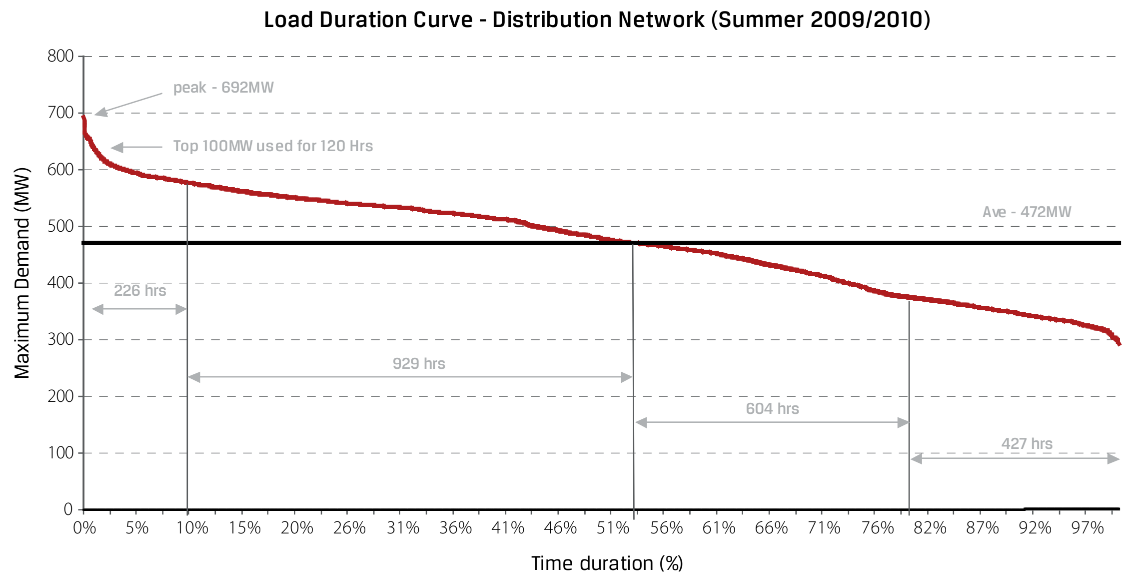


Figure 24 presents the results of a load duration analysis of the distribution network for the summer period (1 December – 28 February) of 2009-10 and presents a similar picture to the winter load duration curve.

Figure 24

Load duration summer 2009-10



The network infrastructure required, and its associated value, to serve 10 percent of the system peak demand for less than 1 percent of the time clearly indicates that the continued sole use of traditional network augmentation to deal with the short duration peaks is an expensive and sub-optimal strategy.

Non-network approaches, such as demand side management and distributed generation options, integrated as part of Aurora's overall planning process, offer a far more cost effective strategy than continuing to allocate scarce capital to serve short duration peak loads.

4.17. Regulatory obligations overview

Clauses 6.5.6(a)(2) and 6.5.7(a)(2) of the *Rules* require that Aurora's *Regulatory Proposal* include the total forecast operating and capital expenditure for the 2012-17 *Regulatory Control Period* which Aurora considers is required in order to "comply with all applicable regulatory obligations or requirements associated with the provision of *Standard Control Services*".

As a regulated business, Aurora operates under a complex regulatory framework. One of the most significant drivers of capital and operating expenditure for Aurora are the activities and processes undertaken in order to meet its diverse range of regulatory obligations. Aurora is required to comply with regulatory and legislative instruments at both the national and jurisdictional level, which include Acts, Laws, Regulations, Rules, codes and guidelines. The obligations placed on Aurora to meet its requirements, and to monitor compliance with these requirements, represents material cost to the business and is a significant component of its capital and operating expenditure forecasts.

Aurora's work program includes forecast capital and operating expenditure to meet its regulatory obligations. This section provides an overview of the key regulatory obligations that Aurora is governed by and that will materially impact on expenditure requirements for the 2012-17 *Regulatory Control Period*. This includes existing, as well as anticipated, requirements.

The compliance activities or processes that Aurora will undertake to meet specific obligations under each of its RIN categories, and the forecast expenditure associated with these activities, are referenced in this *Regulatory Proposal* in chapters 11 & 12 and set out in more detail in Aurora's management plans.

Aurora's compliance activities are underpinned by a group compliance framework which includes a group compliance policy, operational policy and non compliance policy and compliance plan. The preparation of the compliance plan is a condition of Aurora's distribution licence.

The compliance policies outline the principles to be applied to ensure compliance and fulfilment by Aurora with its compliance obligations in all activities undertaken. The objective of the compliance policy is to specify Aurora's approach to compliance; ensure its control systems are widely understood; and set the expected behaviour so that compliance obligations are met. The policy is to be reviewed and endorsed at least on an annual basis or when there is a significant change to the business which may impact the policy.

The compliance policy requires Aurora to conduct its business in such a way as to comply with all its legal obligations as required by statute and common law. The policy states:

"in both its commercial and non-commercial activities, Aurora shall endeavour to act as a model corporate citizen by acting in an ethical manner and in accordance with the spirit, as well as the letter of the law".

Aurora's expenditure is driven by national and jurisdictional regulatory requirements in four key areas, being:

- national electricity industry requirements;
- jurisdictional electricity industry requirements;
- jurisdictional safety and health obligations; and
- jurisdictional environmental and heritage obligations.

These requirements and their expenditure impacts are assessed below.

A comprehensive list of the key legislative and regulatory requirements with which Aurora must comply is set out and appended as an attachment to this *Regulatory Proposal*.

4.17.1. Regulator for 2012-17 Regulatory Control Period

Rules requirements

Chapter 10 of the *Rules* defines the Jurisdictional Regulator as the person authorised by a participating jurisdiction to regulate distribution service prices in that jurisdiction.

Clause 9.48.3 of the *Rules* provides that OTTER will remain as the Jurisdictional Regulator for Tasmania until such time as the Tasmanian Minister makes a transfer of regulatory responsibility to the AER under clause 11.14.4. This clause expires on the first day of Aurora's forthcoming *Regulatory Control Period* (1 July 2012).

Electricity – National Scheme (Tasmania) Act 1999 Requirements

In the context of the *Electricity – National Scheme (Tasmania) Act 1999*, 'regulatory period' means the period commencing on 1 January 2008 and ending on 30 June 2012.

Section 10 provides that, despite any other provision of the Act, any other Act or any other law, jurisdictional laws apply to the operation, administration and enforcement of the relevant Declared Electrical Service Price Determination during the regulatory period to the exclusion of anything to the contrary in the New National Electricity (Tasmania) Law and the New National Electricity Rules.

Section 10 also provides that, on and after the transfer day, any Determinations, arrangements, guidelines or requirements made by the Regulator relating to the relevant Declared Electrical Service Price Determination that were in existence immediately before the transfer day, are taken to have been made by the AER during the regulatory period.

Electricity Supply Industry Act 1995

Section 16A provides that the Minister may enter into an agreement with the Commonwealth in respect of the performance and exercise of any or all of the functions and powers of the Regulator under the Act, the regulations or the *TEC* by the AER.

In accordance with the ESI Act the Regulator is the person appointed in accordance with the *Economic Regulator Act 2009*, which is the Tasmanian Economic Regulator.

On the first day of the forthcoming *Regulatory Control Period* the AER will be responsible for the regulation of distribution service prices in Tasmania. The performance and exercise of the remaining functions and powers of the Regulator that are of relevance to Aurora will remain with OTTER. This arrangement will continue until such time as the Minister enters into an agreement with the Commonwealth to transfer other functions or powers to the AER.

4.17.2. National obligations

As a DNSP in the NEM, Aurora is subject to a diverse range of national regulatory obligations. Importantly, Aurora is required to comply with the NEL and the *Rules*, which have broad impacts across Aurora's work program.

Electricity – National Scheme (Tasmania) Act 1999

The objective of the *Electricity – National Scheme (Tasmania) Act 1999* (National Scheme Act) is to make provision for the operation of a national electricity market and for related purposes. The National Scheme Act provides that the NEL set out in the schedule to the *National Electricity (South Australia) Act 1996* of South Australia, applies in Tasmania. This jurisdictional application Act gives effect to the NEL, which Aurora must comply with as a DNSP in the NEM.

National Electricity Law

The objectives of the *National Electricity Law* (NEL), the National Electricity Objective, are to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.

The NEL also provides for the establishment of the *Rules* and confers powers and responsibilities with respect to the safety and security of the national system.

National Electricity Rules

The *Rules*, which are made under the NEL, provide for the rights and obligations of participants in the NEM, the Australian Energy Market Operator (AEMO) as market operator, and the market institutions. There are numerous requirements for Aurora as a DNSP under the *Rules* and consequently there is significant cost to Aurora in meeting these requirements, which broadly relate to its obligations to:

- register as a network service provider;
- meet power system security standards;
- undertake network connections and metering in the prescribed manner; and
- comply with the economic regulation of distribution services.

4.17.3. Jurisdictional electricity industry obligations

Section 2D of the *National Electricity (South Australia) Act 1996* provides that a regulatory obligation or requirement includes an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that:

- levies or imposes a tax or other levy that is payable by a regulated network service provider;
- regulates the use of land in a participating jurisdiction by a regulated network service provider;
- relates to the protection of the environment; or
- materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a Distribution Determination or Transmission Determination.

Aurora, as DNSP and participant in Tasmania's electricity industry, is subject to several core pieces of industry-specific jurisdictional legislation. Compliance with this legislation has a material impact on its capital and operating expenditure programs. Specific jurisdictional instruments of relevance to Aurora's compliance obligations as a participant in the electricity industry are discussed below.

Electricity Supply Industry Act 1995

The ESI Act is the principal Act governing the operation of the electricity supply industry in Tasmania. The objectives of the ESI Act are:

- to promote efficiency and competition in the electricity supply industry;
- to provide for a safe and efficient system of electricity generation, transmission, distribution and supply;
- to provide for the safety of electrical installations, equipment and appliances;
- to enforce proper standards in the performance of electrical work; and
- to protect the interests of consumers of electricity and for related purposes.

Aurora is further subject to two particular Regulations; namely the *Electricity Supply Industry (Network Performance Requirements) Regulations 2007* and the *Electricity Supply Industry (Contestable Customers) Regulations 2005*. Aurora is also subject to the *TEC* as established under the ESI Act. The Regulations referred to are discussed below.

The ESI Act also:

- requires Aurora, as an electricity entity, to be licensed, and stipulates the conditions that Aurora will be subject to, which are summarised later in this section; and
- establishes OTTER's role as the economic regulator. As discussed above, the AER will regulate distribution service prices, but at this point OTTER will retain the remaining functions and powers under the ESI Act, the regulations or the *TEC*.

Electricity Supply Industry (Network Performance Requirements) Regulations 2007

The *Electricity Supply Industry (Network Performance Requirements) Regulations 2007* (Network Performance Requirements Regulations) has the objective to specify, for the prescribed transmission service, the minimum network performance requirements that a planned power system of a TNSP must meet in order to satisfy the reliability limb of the regulatory test in the *Rules*. This regulation is most likely to impact the Reliability and Quality Maintained and Reliability Quality Improvements capex.

Electricity Supply Industry (Contestable Customers) Regulations 2005

The *Electricity Supply Industry (Contestable Customers) Regulations 2005* (Contestable Customers Regulations) has the objective to establish retail contestability in the Tasmanian electricity market. These regulations place an obligation on Aurora to identify contestable customers on the basis of electricity consumption, and to notify customers of their contestable status (this requirement is not yet part of the regulation, but has been drafted and is soon to be a requirement). This regulation is most likely to impact the NEM and Contestability Related Costs opex.

Tasmanian Electricity Code

The *TEC* has the objective to set out more detailed arrangements for the regulation of the Tasmanian electricity supply industry. It is provided for, and enforceable under, the ESI Act and has been reviewed and revised to ensure that it is consistent with NEM regulatory environment. Aurora incurs significant cost in meeting the *TEC* requirements, specifically in relation to obligations under two key Chapters:

- *Chapter 8 – Distribution System Operation*, specifies the planning obligations; technical standards for quality of network services; access arrangements and standards of service and quality for embedded generators; and a Guaranteed Service Level scheme. The obligations under this Chapter are most relevant to the following categories: GSL Payments opex; Reliability and Quality Maintained; and Reliability and Quality Improvements capex.
- *Chapter 8A – Distribution Powerline Vegetation Management*, provides the requirements to keep vegetation clear of powerlines to manage vegetation related interruptions to supply; to minimise the effect of the management of vegetation around distribution powerlines on the natural environment; and also sets out the works requirements and practices in relation to fire hazard categories. The obligations under this Chapter are most relevant to Vegetation Management opex.

Tasmanian electricity distribution licence

Aurora is obliged to hold a licence for the distribution of electricity under the ESI Act. Aurora's Tasmanian Electricity Distribution Licence (Distribution Licence) sets out the terms and conditions which Aurora must meet. These requirements include: to comply with industry-specific national and jurisdictional instruments; to pay specified fees and charges; and to develop management plans, a vegetation management plan, a compliance plan and an emergency management plan. The Distribution Licence was initially issued in December 1998 and re-issued in December 2008 and has a term of 10 years. The obligations of the Distribution Licence have a wide scope and therefore have a broad impact on Aurora's work program.

Ring fencing guidelines

Aurora operates under a jurisdictional derogation from clause 6.17 of the *Rules* which means that it is not required to comply with the Distribution Ring Fencing Guidelines prepared by the AER, but must instead comply with the Guideline for Ring Fencing in the Tasmanian Electricity Supply Industry (dated October 2004) (Ring Fencing Guideline).

The objective of the Ring Fencing Guideline is to promote competition by ensuring that Aurora, by virtue of its role in providing regulated distribution services, does not gain an advantage in providing contestable services. Accordingly, the Ring Fencing Guidelines set out OTTER's obligations in relation to the separation of regulated electricity distribution activities from other activities carried out by the distributor. Compliance with the Ring Fencing Guideline results in incremental expenditure as Aurora is required to ensure the operational and physical separation of its resources and must engage in regular reporting to the AER.

Guaranteed service level scheme

The Guaranteed Service Level (GSL) Scheme requires that payments are made to eligible customers when they do not receive the relevant guaranteed level of distribution service. The GSL Scheme sets out the value of payments that are to be made to customers on the basis of the number of outages in a 12 month period, and on the basis of the duration, in hours, of a single outage. The GSL Scheme can therefore impose a significant financial burden upon Aurora where interruptions to supply in Aurora's network exceed these limits. The obligations under the GSL Scheme are most relevant to GSL Payments opex.

Energy Ombudsman Act 1998

The *Energy Ombudsman Act 1998* (Ombudsman Act) has the objective to provide for the making, investigation and resolution of complaints against energy entities and for related purposes. Under the Ombudsman Act, a person is entitled to make a complaint if the person has a grievance concerning any service of, or relating to the sale and supply of gas or electricity by an energy entity.

Aurora's obligations in relation to this legislation relate to its requirement to pay compensation, provide goods or services and/or undertake corrective action where the Ombudsman deems it appropriate. Aurora therefore incurs cost in ensuring that it does not breach any applicable customer-related requirements and in instances where the Ombudsman awards costs against it. In relation to its work program, Aurora's system capex will be most impacted by obligations under this Act.

4.17.4. Jurisdictional safety and health obligations

As the owner and operator of a distribution network Aurora is subject to a range of health and safety legislation generally and more specifically in relation to electrical operations. Aurora recognises that protecting its employees and contractors is of paramount importance, and that complying with the relevant legislation is a crucial component of this. Aurora incurs significant incremental cost in meeting its safety and health obligations such as ensuring that it complies with prescribed standards, carries out educational and promotional activities and maintains resources required to monitor and report in relation to these obligations. The obligations of each of the below statutes will have the greatest impact on Aurora's Safety Health and Environment (SHE) and Compliance operating costs.

Electricity Industry Safety and Administration Act 1997

The *Electricity Industry Safety and Administration Act 1997* has the objective to establish safety standards for electrical articles, to provide for the investigation of accidents in the electricity industry and for related purposes.

Aurora's responsibilities pursuant to this Act include its obligation to discontinue electricity supply where appropriate; to repair, replace or relocate its infrastructure where deemed necessary for safety reasons; to contribute to the administration costs of this act where required by the Treasurer; and to develop and obtain approval for an electrical safety management scheme for its employees and contractors.

Workplace Health and Safety Act 1995

The objectives of the *Workplace Health and Safety Act 1995* (WH&S Act) are to provide for the health and safety of persons employed in, engaged in or affected by industry, to provide for the safety of persons using amusement structures and temporary public stands and to repeal certain enactments.

The WH&S Act requires Aurora, as an employer, to take measures to prevent work-related injuries; monitor and keep records of injuries and illnesses suffered by employees; ensure that employees and contractors receive proper information, instruction and training before commencing work; and to monitor working conditions.

Occupational Licensing Act 2005 and Occupational Licensing (Electrical Work) Regulations 2008

The *Occupational Licensing Act 2005* has the primary objective to ensure that contractors, practitioners and other persons engaged in certain occupations, trades or callings are appropriately qualified, licensed and regulated to perform their work safely and in accordance with established benchmarks. The Act also aims to promote safety and to provide for the investigation of incidents in those activities. The Act applies to the performance of electrical work.

4.17.5. Jurisdictional environmental and heritage

There is a diverse range of legislation relating to the protection of Tasmania's natural environment and aboriginal relics. In light of the high value placed by Tasmanians on these issues, Aurora is dedicated to playing its part in safeguarding the natural environment and preserving aboriginal relics, and to meeting any associated regulatory obligations.

The physical scale and location of network infrastructure for which Aurora is responsible, in conjunction with the works required to construct, operate and maintain the network, means that the number of applicable environmental Acts with which Aurora must comply is broad. Although Aurora's work program is impacted to varying extents by most of Tasmania's environmental legislative and regulatory requirements they are not all discussed in this section. A listing of these instruments is appended as an attachment to this *Regulatory Proposal*.

Aurora has developed an Environmental Management System to assist the business in monitoring requirements and subsequent compliance activities[13].

Generally this legislation impacts on capital and operating expenditure requirements by dictating how Aurora undertakes its operations, where capital works activities can occur, and the level of monitoring and reporting activity that is required.

Weed Management Act 1999

The *Weed Management Act 1999* has the objective to provide for the control and eradication of declared weeds and to promote a strategic and sustainable approach to weed management. Aurora is obliged to comply with a range of restrictions in relation to an infested or protected area. These include restrictions on movement into and out of infested areas; the requirement for a permit to work in an infested area; and prescribed compliance measures for using infested equipment.

Threatened Species Protection Act 1995

The *Threatened Species Protection Act 1995* has the objective to provide for the protection and management of threatened native flora and fauna and to enable and promote the conservation of native flora and fauna. Aurora's obligations as a landholder are to comply with any interim protection order to conserve a habitat, not disturb specified flora and fauna, and pay compensation where disturbance is caused. The regulations prescribe further obligations with respect to maintaining and providing details of dealings with listed flora and fauna and the penalty for contravention of a conditions permit.

Aboriginal Relics Act 1975

The *Aboriginal Relics Act 1975* has the objective to make provision for the preservation of aboriginal relics. This Act impacts on the way in which Aurora carries out its operations on protected sites by restricting the activities that can be carried out on land where aboriginal relics are declared to exist.

13 Ibid. page 57.

Historic Cultural Heritage Act 1995

The *Historic Cultural Heritage Act 1995* has the objective to promote the identification, assessment, protection and conservation of places having historic cultural heritage significance and to establish the Tasmanian Heritage Council. Aurora must comply with a number of obligations under this Act that impact on its operations in declared heritage areas. Aurora is not able to carry out any works within a heritage area unless the Heritage Council has granted an exemption or the works are approved under the Act.

4.17.6. Obligations to commence in 2012-17 Regulatory Control Period

National energy customer framework

The *National Energy Customer Framework* (NECF) was developed at national level to govern the sale and supply of energy (electricity and natural gas) to retail customers and is based on triangular contractual relationships between customers, retailers and DNSPs. The NECF package was passed by the South Australian parliament in March 2011, and enabling legislation is scheduled to be passed in the Tasmanian jurisdiction by 1 July 2012.

NECF involves the creation of a new:

- National Energy Retail Law;
- National Energy Retail Rules;
- National Regulations; and
- *Rules*, Chapters 5A and 6B.

NECF is expected to provide efficiencies and reduce the regulatory burden for energy businesses, particularly retailers operating across jurisdictions and fuels.

The NECF includes a range of provisions, the implementation of which will impact on Aurora. In particular, the NECF will require Aurora to:

- establish three categories of connection services, being basic, standard and negotiated connections;
- comply with the prescribed connection process and timeframes for the connection of customers under basic, standard and negotiated connections;
- comply with AER guidelines on processes for AER compliance monitoring and enforcement activity; and importantly, on the operation of a Retailer of Last Resort Scheme; and
- comply with connection charging principles and submit a Connection Policy as part of its *Regulatory Proposal* for approval by the AER.

The implementation of the NECF is likely to be a significant project for Aurora and will impose a financial burden on Aurora as it revises operations to accommodate changes to billing, data management, contracts and agreements, and planned interruptions procedures and systems. These obligations will impact most directly on Network Management and Other Operating Costs opex; and potentially on IT and Communications capex.

Electricity Supply Industry Expert Panel Act 2010

The objective of the *Electricity Supply Industry Expert Panel Act 2010* is to establish the Electricity Supply Industry Expert Panel to conduct a review into the electricity supply industry and for related matters. The outcomes of the review may result in a restructure of Tasmania's electricity supply industry, and potentially place a significant financial burden on Aurora.

5. Transitional issues

5. Transitional issues

The *National Electricity (Economic Regulation of Distribution Services) Amendment Rules 2007* which commenced on 16 December 2007 replaced the then Chapter 6 of the *Rules*. Following this amendment, the responsibility for economic regulation of distribution services was transferred to the national AER, effective 1 January 2008.

In addition to the amendments to Chapter 6 of the *Rules*, the Ministerial Council on Energy (MCE) also established *Transitional Rules* to preserve specific arrangements in the various jurisdictions. These *Transitional Rules*[1], applicable to the first Distribution Determination under the AER, are required to facilitate an orderly transition from the jurisdictional arrangements to the national framework.

There are no transitional arrangements for the first Distribution Determination for Aurora outlined in Chapter 11 of the *Rules*. There are therefore no transitional arrangements that will apply to Aurora for the 2012-17 *Regulatory Control Period*.

Whilst there are no specific issues identified in Chapter 11 of the *Rules* Aurora however considers that there are other issues that should be addressed by the AER in the 2012-17 Distribution Determination.

This chapter sets out Aurora's transitional issues for the 2012-17 Distribution Determination.

5.1. Regulatory information requirements

Aurora's RIN requires it to provide information on issues which Aurora expects will have a substantial impact on it and arise from the transition from the current *Regulatory Control Period* to the forthcoming *Regulatory Control Period*.

5.2. Summary

Aurora considers that the following issues under OTTER's existing arrangements will have a material impact on it in the transition to the 2012-17 *Regulatory Control Period* and need to be addressed by the AER in its Distribution Determination:

- the treatment of the Regulatory Asset Base;
- "unders and overs" of the revenue cap;
- the treatment of TUOS cost; and
- the treatment of shared services.

1 *Rules* Chapter 11.

5.3. Treatment of the regulatory asset base

The Regulatory Asset Base (RAB) for Aurora includes some non-system assets used to provide *Alternative Control, Negotiated and Unregulated Services*. To ensure that there are no cross subsidies between *Standard Control Services* and *Alternative Control, Negotiated and Unregulated Services*, Aurora proposes that the PTRM for *Standard Control Services* be adjusted to account for the portion of assets from the RAB that is used to deliver *Alternative Control, Negotiated and Unregulated Services*.

Further details of the proposed approach are outlined in chapter 19 of this *Regulatory Proposal*.

5.4. Unders and overs of the revenue cap

Under the revenue cap control mechanism outlined in OTTER's 2007 Pricing Determination, there is an adjustment for the surplus or shortfall of actual revenue compared to the revenue target each year. The quantum of the unders or overs variance is assessed as part of the allowable revenue calculation for each Regulatory Year. This variance is generally cleared two years after its occurrence.

Adjustments to determine the revenue to be collected in 2012-13 and 2013-14 to account for any under or over recoveries in 2010-11 and 2011-12 will be required. Aurora proposes that a similar treatment to the unders and overs for 2010-11 and 2011-12 revenue be adopted. These adjustments are incorporated into the revenue requirement as outlined in chapter 23 of this *Regulatory Proposal*.

For the 2012-17 *Regulatory Control Period*, Aurora's *Standard Control Services* will continue to be under a revenue cap form of control mechanism. Aurora proposes that OTTER's approach to unders and overs recovery be adopted for the 2012-17 *Regulatory Control Period*.

5.4.1. Operation of the unders and overs mechanisms

The proposed adjustment process will involve an assessment of the actual and expected revenue recovery at the end of each financial year. A comparison of the allowed and expected revenue for each year is made to assess the variance.

The proposed operation of unders and overs of the revenue cap control mechanism will include an adjustment for the WACC allowance. The adjustment for the WACC allowance is to ensure an NPV neutral position for both Aurora and its customers.

The timing of the annual reporting and price approval process means that the final comparison of actual and allowed revenues cannot occur until two years after Aurora collects its revenue. To alleviate this lag, Aurora proposes that the adjustment is undertaken as a two-step process.

Step one

As part of the annual price approval process Aurora will undertake an assessment of expected total revenues for the regulatory period. This expected revenue will be compared to the allowed revenues for the same period to determine any variance. This variance will be adjusted by CPI and WACC to ensure an NPV neutral position.

Step two

As part of the subsequent annual price approval process Aurora will compare actual total revenues for the regulatory period to the expected revenues assessment from the previous price approval process to determine any final variances. This variance will be adjusted by CPI and WACC to ensure an NPV neutral position.

A worked example of Aurora's proposed unders and overs revenue cap adjustment methodology is appended as an attachment to this *Regulatory Proposal*.

5.5. TUOS cost

Aurora connects to the Transend network at multiple connection points. Transend recovers its allowable revenue from any directly connected customers and Aurora.

In accordance with the connection agreement with Transend, Aurora is required to pay TUOS charges to Transend on a monthly basis. The TUOS charges comprise fixed charges and variable components based on metered energy at each of the connection points. A forecast of the TUOS charges is provided by Transend to allow Aurora to develop network prices (DUOS, TUOS and metering) for the annual approval of OTTER. The actual TUOS payment to Transend is based on the metered energy at each connection point.

Aurora's network charge to customers, billed via the retailers, includes this TUOS component. This recovery of TUOS is separately identified in invoices to retailers and is also reported in the Regulatory Accounts to OTTER.

In accordance with OTTER requirements, TUOS cost and revenue are specifically identified and reported, with a reconciliation undertaken annually as part of the separate unders and overs process. Any variance will be adjusted by CPI and WACC to ensure an NPV neutral position.

Aurora proposes that this approach be adopted in the 2012-17 *Regulatory Control Period*. A worked example of Aurora's proposed unders and overs TUOS cost adjustment methodology is appended as an attachment to this *Regulatory Proposal*.

6. Outcomes of AER's Framework and Approach and classification

6. Outcomes of AER's Framework and Approach and service classification

6.1. Framework and Approach

The *Framework and Approach* is the first step in the making of a Distribution Determination under Part E of Chapter 6 of the *Rules*, setting out:

- the AER's likely approach to the classification of distribution services;
- the forms of control to be applied to the classified services;
- a statement of the AER's likely approach to cost allocation;
- the application of schemes; and
- any other matters that the AER considers may give an indication of its proposed approach.

In the case of Aurora, the AER issued a preliminary positions paper for consultation on 25 June 2010, with the AER's final decision being released on 29 November 2010.

The main points of the *Framework and Approach* are summarised in the following sections.

6.2. Classification of services and forms of control

The AER has discretion under Part B of Chapter 6 of the *Rules* to regulate, or not to regulate distribution services provided by a DNSP. Regulated services may be classified as either *Direct Control Services* or *Negotiated Distribution Services*, with *Direct Control Services* further classified as *Standard Control Services* or *Alternative Control Services*.

The AER proposes to group Aurora's distribution services into six categories:

- network services;
- metering services;
- public lighting services;
- fee-based services;
- connection services; and
- quoted (non-standard) services.

In addition to classification, the AER has also applied a form of regulatory control to each service or group of services.

The AER's proposed classification of Aurora's distribution services and associated forms of control are discussed in more detail below.

6.2.1. Network services

Network services are considered by the AER to:

> *"..predominantly relate to services provided over the shared network used to service all network users connected to it. Such services may include the construction, maintenance, operation, planning and design of the shared network. Network services are delivered through the provision and operation of apparatus, equipment, plant and / or buildings (excluding connection assets) used to convey, and control the conveyance of, electricity to customers. Such assets include poles, lines, cables, substations, communication and control systems, and involve activities such as inspection, testing, repairs, maintenance, vegetation clearing, asset replacement, asset refurbishment and asset construction services that are not connection services. Network services also include the provision of emergency response and administrative support for other network services."*

The AER has classified network services as *Direct Control, Standard Control Services*, with the form of control being a revenue cap.

Aurora has prepared its network services proposal in accordance with the *Rules* and the AER's final *Framework and Approach* and this is discussed in detail in chapters 11 and 12 of this *Regulatory Proposal*.

6.2.2. Metering services

Metering services are considered by the AER to be:

> *"..limited to the costs of providing, installing and maintaining standard meters and services provided to non-contestable customers to support the customer billing system..the term 'standard metering services' includes metering services provided using type 5, type 6 and type 7 meters. For clarity, standard metering services includes those type 6 meters owned by Aurora to which a Payguard unit can be attached, but excludes those meters provided by Aurora Retail.*

The AER has classified metering services as *Direct Control, Alternative Control Services*, with the form of control being a price cap. Price setting may be via the currently used annuity approach, although the AER will investigate whether an alternative approach (perhaps using a RAB for standard metering services) is more appropriate.

Type 1 to 4 metering services, and meters provided by Aurora Retail to provide PAYG services will be unregulated.

Aurora has prepared its metering services proposal in accordance with the *Rules* and the AER's final *Framework and Approach* and this is discussed in detail in chapter 33 of this *Regulatory Proposal*.

6.2.3. Public lighting services

The provision of public lighting services contains several aspects. The AER has classified:

- the [routine] repair, replacement and maintenance of Aurora's public lighting assets as a *Direct Control, Alternative Control Service* with the form of control being a price cap;
- the [routine] repair, replacement and maintenance of public lighting owned by third parties (where Aurora undertakes the service for a fee) as a *Direct Control, Alternative Control Service* with the form of control being a price cap;
- the provision of new public lighting assets (standard and non-standard provision) as a *Direct Control, Alternative Control Service* with the form of control being a price cap;
- the provision of new public lighting technologies, as a *Negotiated Distribution Service*; and
- the alteration and relocation of public lighting assets as a quoted service, which is proposed to be classified as a *Direct Control, Alternative Control Service*.

Price setting for the first three aspects may be via the currently used annuity approach, although the AER will investigate whether an alternative approach (perhaps using a RAB) is more appropriate.

Aurora has prepared its public lighting services proposal in accordance with the *Rules* and the AER's final *Framework and Approach* and is discussed in detail in chapter 33 of this *Regulatory Proposal*.

6.2.4. Fee-based services

Aurora provides a range of fee-based 'special services'. These services are, in general, provided for the benefit of a single customer rather than uniformly supplied to all network customers. For many of these special services a fixed fee can be set in advance.

In the current regulatory period OTTER defined two sets of such services. A reference set of special services contains the following categories of service for customers:

- energisation, de-energisation and re-energisation;
- meter alteration; and
- meter testing,

that are regulated by OTTER through a weighted average price cap. Aurora also provides several special services that are generally provided as a result of a customer or retailer request and are categorised by Aurora as:

- new connection – permanent supply;
- supply abolishment – removal of meters and service connection;
- renewable energy connection;
- new connection – temporary and temporary 'in permanent position';
- new connection – temporary show and carnival connection
- truck tee-up; and
- other miscellaneous services.

The AER has classified fee-based services, which include both the reference set of special services and other distribution special services, as *Direct Control, Alternative Control Services*. The AER proposed that the form of control be a price cap but did not suggest a mechanism in the final *Framework and Approach*.

Aurora has prepared its fee-based services proposal in accordance with the *Rules* and the AER's final *Framework and Approach* and this is discussed in detail in chapter 33 of this *Regulatory Proposal*.

6.2.5. Connection services

The *Rules* define connection services as consisting of *Entry Services* and *Exit Services*. An *Entry Service* is a service provided to serve a generator or group of generators, or a network service provider or group of network service providers, at a single connection point. An *Exit Service* is a service provided to serve a distribution customer or a group of distribution customers, or a network service provider or group of network service providers, at a single connection point.

The provision of connection services includes:

- the construction of shared network assets and connection assets, potentially with customer capital contributions towards the cost of construction;
- the energisation of de-energised installations, whether new or otherwise; and
- the maintenance of those assets to ensure continuity of supply.

The energisation component of connection services is considered to be a fee-based service, which the AER has classified as *Direct Control, Alternative Control Services*.

The AER has classified all other connection services as *Direct Control, Standard Control Services*.

The AER considers that the capital contributions component of connections requiring augmentation paid by customers will remain unregulated.

Aurora has prepared its connection services proposal in accordance with the *Rules* and the AER's final *Framework and Approach* and this is discussed in detail in chapters 11 and 12 of this *Regulatory Proposal*.

6.2.6. Quoted (non-standard) services

Aurora provides a range of non-standard services on a quoted basis including, but not limited to:

- removal or relocation of Aurora's assets at a customer's (for example, the Tasmanian Government's) request;
- services that are provided at a higher standard than the standard service, due to a customer's request for Aurora to do so; and
- services that are provided through a non-standard process at a customer's request (for example, where more frequent meter reading is required).

The nature and scope of these services are specific to individual customers' needs, and vary from customer to customer. In consequence, the cost of providing the services cannot be estimated without first knowing the customer's specific requirements. It is not possible, therefore, to set a generic total fixed fee in advance for these services.

The AER has classified these quoted services as *Standard Control Services, Alternative Control Services*. The AER proposed that the form of control be a price cap but did not suggest a mechanism in the *Framework and Approach*.

Aurora has prepared its quoted services proposal in accordance with the *Rules* and the AER's final *Framework and Approach* and this is discussed in detail in chapter 33 of this *Regulatory Proposal*.

7. Key assumptions

7. Key assumptions

Schedule 6.1.1 of the *Rules* requires that Aurora's building block proposal must include, in relation to capital expenditure, the key assumptions that underlie the capital expenditure forecast; and a certification of the reasonableness of the key assumptions by Aurora's directors.

Schedule 6.1.2 of the *Rules* requires that Aurora's building block proposal must include, in relation to operating expenditure, the key assumptions that underlie the operating expenditure forecast; and a certification of the reasonableness of the key assumptions by Aurora's directors.

Further, the RIN issued by the AER in April 2011 sets out specific key assumptions for which Aurora is required to provide prescribed information to the AER. For capital and operating expenditure the AER requires Aurora to identify key assumptions, and the associated quantum where relevant, for each of the following:

- forecast capital or operating expenditure proposal and its preparation;
- capital or operating expenditure category and its preparation; and
- each material program relating to each capital or operating expenditure category and its preparation.

For each of the above assumptions Aurora is required to provide:

- the method and information used to develop the assumption;
- how the assumption has been applied and taken into account;
- for capital expenditure, the effect or impact of the assumption on the forecast level of capital expenditure in the forthcoming *Regulatory Control Period*; and
- for operating expenditure, the effect or impact in comparison to its effect or impact on actual operating expenditure incurred in the previous and current *Regulatory Control Periods*.

Ideally, and where at all possible, Aurora's *Regulatory Proposal* uses actual amounts, values and inputs to build its capital and operating expenditure forecasts for the 2012-17 *Regulatory Control Period*. However, in the absence of certainty relating to specific amounts, values and inputs, Aurora has been obliged to make assumptions using available information at the time of preparing its *Regulatory Proposal*.

In accordance with the *Rules* and the requirements of the RIN issued by the AER, this chapter sets out a range of assumptions relevant to Aurora's capital and operating expenditure forecasts. This *Regulatory Proposal* groups assumptions by the level of granularity associated with each assumption and its impact on expenditure forecasts. The following three assumption categories are set out in this *Regulatory Proposal*:

- at the highest level are Aurora's global assumptions which incorporate broad assumptions that will impact across multiple capital expenditure and operating expenditure forecasts;
- at the intermediate level are the key assumptions (as defined by the AER in the RIN) which are central to Aurora's capital and operating expenditure forecasts, and as such the AER prescribes the information which Aurora must provide on these assumptions; and
- at the lowest level are the assumptions made that are specific to forecasts for each of Aurora's RIN sub-categories.

The information provided within this chapter of the *Regulatory Proposal* is supplementary to that set out in the RIN.

7.1. Global assumptions

As discussed above, Aurora has made a range of global assumptions that can be applied across multiple categories of its capital and operating expenditure forecasts. The level of detail provided for each assumption and its impacts is high level to ensure the broad application across Aurora's capital and operating expenditure categories is shown in Table 20.

Table 20

Summary of globally applied assumptions

Nature of assumption	Method/information to develop assumption	Application of the assumption	Impact of the assumption
Strategic Plan Aurora has assumed that the new direction encapsulated by the 2011-16 Strategic Plan will underpin its strategic direction across the entire 2012-17 *Regulatory Control Period*. Further details of the Aurora Strategic Plan are discussed in chapter 3 of this *Regulatory Proposal*.	Aurora has made this assumption with regard to the underlying objectives and strategies documented in the Aurora 2011-16 Strategic Plan and associated material. Specifically this plan sets out strategies to: • enhance the efficiency of work delivery processes; • manage the distribution system within expenditure constraints and acceptable risks; and • align and remove duplication of activities.	This assumption applies across Aurora's capital and operating expenditure forecasts.	The impact of this assumption is that capital and operating expenditure forecasts are below what they would have been in the absence of the strategy.
Smarter network investment Aurora has assumed that, consistent with its 2011-16 Strategic Plan, it will adopt a more innovative approach to delivering customer outcomes whilst minimising consequent price increases over the 2012-17 *Regulatory Control Period*. This smarter approach will include activities such as: • seeking an optimised balance between age and condition-based replacement; and • the phased and considered implementation of smarter network technology.	Aurora has made this assumption with regard to the underlying objectives and strategies documented in the Aurora 2011-16 Strategic plan and associated material.	This assumption applies primarily to Aurora's capital expenditure forecasts, with other benefits possible for operating expenditure.	The impact of this assumption is that Aurora's capital and operating expenditure forecasts include the expected efficiencies that will be derived from the implementation of this smarter approach.

Table 20

Summary of globally applied assumptions (continued)

Nature of assumption	Method/information to develop assumption	Application of the assumption	Impact of the assumption
Internal operating environment Notwithstanding the review of the Tasmanian electricity supply industry being undertaken by the Expert Panel, Aurora has assumed that the structure of Aurora's business and its ownership arrangements will apply for the entire 2012-17 *Regulatory Control Period.*	Aurora has made this assumption based on an understanding of anticipated business and ownership arrangements. Although there may be changes subsequent to the Expert Panel review, the potential outcomes are too uncertain at this stage to make provision for.	This assumption applies across Aurora's capital and operating expenditure forecasts.	The impact of this assumption means that there have been no provisions made in capital and operating expenditure forecasts for any changes to Aurora's ownership or business structures during the 2012-17 *Regulatory Control Period.*
Internal planning Aurora has assumed that there will be no material impacts on capital and operating expenditure as a result of amendments to Aurora's internal plans, processes, procedures or systems in the forthcoming *Regulatory Control Period.*	Aurora has made this assumption based on an understanding of the framework proposed to apply for the 2012-17 *Regulatory Control Period* for its internal plans, processes, procedures and systems.	This assumption applies across Aurora's capital and operating expenditure forecasts.	The application of this assumption means that no funding provisions have been made for any material changes to capital or operating expenditure forecasts for internal plans, policies, processes, procedures or systems in the 2012-17 *Regulatory Control Period*.
Legislative and regulatory framework Notwithstanding the review of the Tasmanian electricity industry being undertaken by the Expert Panel, Aurora has assumed that there will be no material amendments to the legislative and regulatory framework in the 2012-17 *Regulatory Control Period*, over and above that anticipated and accounted for in the expenditure forecasts.	Aurora has made this assumption based on knowledge of the current and anticipated future legislative and regulatory environment. Aurora has also had regard for known government policy positions on these matters. Analysis of anticipated regulatory changes to apply during the 2012-17 *Regulatory Control Period* is set out in section 4.17 of this *Regulatory Proposal.*	This assumption applies across Aurora's capital and operating expenditure forecasts.	The application of this assumption impacts on the capital and operating expenditure categories which are driven by legislative and regulatory requirements. As material changes to regulatory and legislative frameworks are not included in forecasts, any material costs could only be passed through to customers if Aurora meets the *Rules* requirements for a pass-through event.

Table 20

Summary of globally applied assumptions (continued)

Nature of assumption	Method/information to develop assumption	Application of the assumption	Impact of the assumption
National Energy Customer Framework (NECF)			
Aurora has assumed that the NECF package will commence within the Tasmanian jurisdiction as of 1 July 2012 and the final Tasmanian package will not materially deviate from that proposed at the time of drafting this *Regulatory Proposal*.	Aurora has made this assumption on the basis of: • the provisions of the National Electricity Retail Law and other associated instruments that were established by the South Australian parliament in early 2011; and • jurisdictional policy decisions regarding the implementation of NECF in Tasmania.	This assumption applies primarily to operating expenditure required for implementation activities to accommodate changes to Aurora's procedures, processes and systems as a result of NECF requirements.	The impact of the assumptions is that there should be no additional costs on Aurora as a result of compliance with NECF requirements.
Carbon pricing			
Aurora has assumed that there will not be a price on carbon during the 2012-17 *Regulatory Control Period*. Although the Australian Government has foreshadowed the commencement of a carbon pricing mechanism on 1 July 2012, there is uncertainty regarding likely time and policy direction of the proposed mechanism and Aurora will consider this position further in its response to the AER's draft Determination. It is reasonable to assume any costs arising from the introduction of a carbon tax will be fully passed through to customers.	Aurora has made this assumption based on the current carbon pricing policy position of the Australian Government.	This assumption applies to the underlying assumptions used to forecast Aurora's capital and operating expenditure. In particular demand, energy consumption and cost escalation forecasts are impacted by this assumption.	The impact of this assumption is that underlying forecasts do not account for the impacts of a price on carbon. Therefore demand and energy consumption forecasts are higher, and cost escalation forecasts are lower, than if a carbon pricing mechanism had been accounted for.
Current works and programs			
Aurora has assumed that the required works and programs for the current *Regulatory Control Period* will be delivered within the current period.	Aurora has based this assumption on analysis of forecast and actual expenditure for its current *Regulatory Control Period*.	This assumption applies across Aurora's capital and operating expenditure forecasts.	The application of this assumption impacts on the forecast work program, which will not need to comprise works and programs not completed during the current *Regulatory Control Period*.

Table 20

Summary of globally applied assumptions (continued)

Nature of assumption	Method/information to develop assumption	Application of the assumption	Impact of the assumption
Workforce capacity Aurora has assumed that it will have the resource availability and capability to deliver the programs as forecast for the 2012-17 *Regulatory Control Period*.	Aurora has based this assumption on the deliverability plans in place within Network Services division and appended as an attachment to this *Regulatory Proposal*.	This assumption applies across Aurora's capital and operating expenditure forecasts.	The impact of this assumption is that Aurora will be able to complete the capital expenditure and operating expenditure allowances as set out in this *Regulatory Proposal*.
Age of assets Aurora has assumed that capital expenditure forecasts can be estimated based predominantly on asset age data. Aurora has used age and other condition information, such as failures and condition to create a proxy for risk. Historically Aurora has used age-based replacement strategies, however over the 2012-17 *Regulatory Control Period* it will employ a greater degree of condition-based decision-making.	Aurora has based this assumption on the basis of previous practices.	This assumption applies to Aurora's capital expenditure forecasts.	The impact of this assumption is that Aurora's forecasts for condition-based categories will be based on age and risk-based strategies, although in practise Aurora will transition to condition-based assessments across the 2012-17 *Regulatory Control Period*.
Planning and reliability standards Aurora has assumed that the planning and reliability standards as currently used by Aurora will continue to apply in the current form into the 2012-17 *Regulatory Control Period*.	Aurora has based this assumption on an understanding of internally determined intentions for planning standards and the reliability standards currently within the TEC.	This assumption applies across Aurora's capital and operating expenditure forecasts.	The impact of this assumption is that Aurora's capital and operating expenditure forecasts are driven by the requirement to comply with Aurora's internal planning standards and the TEC reliability standards.
Historical expenditure Aurora has assumed that historical expenditure and volumes are a valid basis to build forecasts for 2012-17 *Regulatory Control Period* expenditures and volume.	Aurora has based this assumption on analysis of historical and actual capital expenditure.	This assumption applies across Aurora's capital and operating expenditure forecasts.	The impact of this assumption is that Aurora's capital and operating expenditure forecasts are based largely on historical expenditures and volumes and are consistent with the expenditure levels in the latter period of the current *Regulatory Control Period;* with adjustments made to account for factors specific to the 2012-17 *Regulatory Control Period*.

7.1.1 Forecast of peak demand

The RIN requires that Aurora provide, describe and explain how the key assumptions have been used to prepare the methodology for its maximum demand forecasts.

The highest level assumption relating to peak demand is that actual demand in the 2012-17 *Regulatory Control Period* will not materially deviate from the peak demand forecast prepared for Aurora by ACIL Tasman. Drilling down, the development of peak demand assumptions necessarily involves a series of assumptions and forecasts to build a macroeconomic outlook on which to ultimately base peak demand assumptions.

Method and information to develop assumption

ACIL Tasman prepared its forecast of peak demand primarily on the basis of the analysis of a range of economic indicators and external sources.

ACIL Tasman's underlying approach is to project load growth forward at each connection site at a rate that is consistent with recent history. These spatial forecasts are then aggregated together, using diversity factors, to a system level forecast (bottom-up).

This bottom-up forecast is then compared to, and reconciled with, a forecast at the system level (top-down). Transend provided the system level forecast which had been prepared independently by the National Institute of Economic and Industry Research (NIEIR). Spatial forecasts, in MW and MVA, are prepared for the individual connection sites.

Demand forecasts are prepared for both summer (December to February) and winter (June to August) periods.

Once data has been temperature/weather corrected and adjusted for large block loads and permanent transfers, demand forecasts are produced.

The forecasts are then reconciled with the medium economic growth scenario of the independently produced system level forecast by applying a proportional adjustment to each of the individual substations so that the sum of the coincident demands corresponds to the independent system demand forecast in each year of the forecast period.

Application of the assumption

This assumption applies to demand-based expenditure on the distribution network and new customer connections capital works. The application of this assumption means that capital expenditure forecasts have been developed to meet the peak demand forecasts prepared by ACIL Tasman.

Aurora's forecasts for peak demand are further outlined in chapter 10 of this *Regulatory Proposal*.

7.1.2. Forecasts of energy consumption

The RIN requires that Aurora provide, describe and explain how the key assumptions have been used to prepare the methodology for its energy consumption forecasts. This also includes a requirement for Aurora to set out assumptions relating to average customer usage by customer type.

The key assumptions associated with Aurora's energy consumption forecasts include the consideration of multiple macroeconomic indicators as well as consideration of the anticipated policy environment at both the National and local levels.

Method and information to develop assumption

Aurora's energy consumption forecasts were prepared by Aurora and reviewed by ACIL Tasman on the basis of analysis and assumptions made on a range of factors used to develop Aurora's demand forecasts. These factors included National and Tasmanian considerations.

The purpose and underlying methodology of the consumption model is to project energy consumption forecasts forward at a rate that is consistent with recent history for each tariff class at an aggregated group level. Forecasts include the use of a growth factor that has been constructed to account for weather (summer and winter) and economic factors that are applied to the aggregated tariff class for low, medium and high outlooks.

ACIL Tasman has reviewed Aurora's adopted methodology and considers that the correlation between demand and energy is weak and that each customer class has underlying drivers that create different growth factors. ACIL Tasman has recommended that Aurora undertake a regression-based approach using credible econometric data (if available), including population growth (residential customers) and gross state product (small and medium business customers), as supplied by suitable economic forecasters.

ACIL Tasman considers this particularly relevant as energy consumption for the past two years has been less than the historical trend and it is unclear whether this is due to either price or demand (or both) impacts.

In light of the recommendations made by ACIL Tasman, Aurora has commissioned ACIL Tasman to undertake further analysis of expected consumption forecasts. Unfortunately this report was not available to Aurora at the time of submitting this *Regulatory Proposal* and Aurora has utilised the energy forecasts derived under Aurora's original methodology. Aurora will make the amended ACIL Tasman report available to the AER once it is received.

Should the amended ACIL Tasman methodology result in changes to Aurora's energy consumption forecasts Aurora will address those changes in its response to the AER's draft determination

Application of the Assumption

The key assumptions listed above are then aggregated to form an economic outlook which can be used to forecast energy consumption across Aurora's network. This will be used to develop pricing arrangements for *Standard Control Services*.

Impact of the Assumption

This assumption has no direct application to the expenditure forecasts for the 2012-17 *Regulatory Control Period*. The assumptions will however have a bearing on the final prices that customers can expect to pay through the tariffs that Aurora will design from its allowable revenue stream.

Aurora's forecasts for energy consumption are further outlined in chapter 10 of this *Regulatory Proposal*.

7.1.3. Forecasts of customer numbers

The RIN requires that Aurora provide, describe and explain how the key assumptions have been used to prepare the methodology for its customer numbers forecasts. This also includes a requirement for Aurora to set out assumptions relating to average customer usage by customer type.

At the highest level it is assumed that the actual customer numbers for the 2012-17 *Regulatory Control Period* will not materially deviate from the forecasts prepared by ACIL Tasman.

Method and information to develop assumption

The forecast of customer numbers for the period 2011-17 has been prepared by ACIL Tasman.

ACIL Tasman has opted to apply an econometric methodology to forecast new customer connections in the Aurora network. This approach requires the estimation and testing of statistical relationships between the number of new connections and the underlying drivers that influence the number of new connections.

The most obvious driver for new residential and commercial connections is the number of new buildings. ACIL Tasman has utilised the ABS Building Approvals Series[1] and Building Activity Series[2] for Tasmania as a proxy for the level of building activity.

The econometric approach utilised by ACIL Tasman entails the establishment of a relationship between the number of new connections and building activity. This relationship is used to forecast new connections based upon projections of building activity.

The Housing Industry Association (HIA) is one potential source of residential construction activity forecasts. The HIA model produces forecasts for new housing, renovations, non-residential buildings and engineering construction. Unfortunately the HIA forecasts are for only two years.

ACIL Tasman has also utilised forecasts provided by the Construction Forecasting Council (CFC). A key advantage of the CFC forecast is that they extend beyond five years.

ACIL Tasman has utilised an historical time trend for the number of new irrigation connections due to the unavailability of any significant statistical independent reports.

Application of the assumption

Aurora has used customer numbers forecasts to develop:

- new customer connection capital expenditure forecasts;
- the scale escalator applied to its capital expenditure forecasts; and
- the scale escalator applied to its operating expenditure forecasts.

Impact of the assumption

Customer growth assumptions apply to customer initiated works and as such this assumption is used as a key input to develop new customer connections capital expenditure forecasts for the 2012-17 *Regulatory Control Period*.

Aurora's forecasts for customer numbers are further outlined in chapter 10 of this *Regulatory Proposal*.

7.1.4. Unit costs

The RIN defines the unit rates applied to key items of plant and equipment as key assumptions and requires that Aurora distinguish between material and labour rates. It also requires that each unit rate should be identified in conjunction with associated key assumptions.

Method and information to develop assumption

This assumption is based on analysis of historical and actual work programs carried out within Aurora. This analysis results in a number of unit rates that are applicable to the work activities undertaken by Aurora.

Application of the assumption

This assumption applies across Aurora's capital and operating expenditure forecasts.

Impact of the assumption

Unit rates are applied to key items of plant and equipment for both labour and material unit rates. The unit rates currently incurred by Aurora and reflected in the current average costs of works have been utilised as the basis for future unit rates.

Aurora internally derives its input costs on the basis of the current average costs of undertaking similar projects and capital and operating work programs over the current *Regulatory Control Period*.

These unit rates represent an aggregation of materials and other costs such as labour required to complete the works. This assumption applies to all expenditure forecasts.

There is no impact on the 2012-17 forecast operating and capital expenditure compared to current *Regulatory Control Period* expenditure resulting from the unit rates key assumption.

Aurora's unit costs are further outlined in chapter 18 of this *Regulatory Proposal*.

1 ABS: Catalogue number 8731.0.
2 ABS: Catalogue number 8752.0.

7.1.5. Labour expenditure escalators

The RIN requires that each labour escalator should be identified in conjunction with associated key assumptions. It requires that Aurora explain any assumptions for:

- the methodology underlying the calculation of each escalator including lags, or
- the weightings given to each escalator.

To prepare its suite of labour cost escalators it has been assumed that the next Aurora Enterprise Agreement negotiation will result in wage increases in line with CPI increases only.

Method and information to develop assumption

In the preparation of its unit rates for labour, plant and equipment, Aurora engaged the services of SKM to review the factors likely to affect price escalation in the consumer price index over the year to June periods between 2009-10 to 2016-17.

SKM has chosen to adopt the method of forecasting CPI used by the AER in the Final Decision for NSW distribution businesses. This method adopts the following process:

- plot two years of forecasts from the most recent RBA Monetary Policy Statement; and
- thereafter plot CPI as the RBA inflation target's midpoint of 2.5 percent.

Application of the assumption

This assumption applies across Aurora's capital and operating expenditure forecasts.

Impact of the assumption

Labour escalator assumptions apply to all capital and operating expenditure forecasts and as such have been applied to the expenditure forecasts for the 2012-17 *Regulatory Control Period*.

7.1.6.Material expenditure escalators

The RIN requires that each material escalator should be identified in conjunction with associated key assumptions. It requires that Aurora explain any assumptions for:

- the methodology underlying the calculation of each escalator including lags, or
- the weightings given to each escalator.

In the preparation of its unit rates for key pieces of plant and equipment, Aurora engaged the services of SKM, which has expertise in researching the increasing cost of capital infrastructure works in the electricity industry, to review the factors likely to affect the escalation of material costs between 2009-10 to 2016-17. SKM used a set of assumptions, which it deemed reasonable, with respect to the likely rate of annual material cost escalation that will be incurred during the 2012-17 *Regulatory Control Period*.

Method and information to develop assumption

Firstly, SKM developed assumptions and forecasts regarding a range of economic cost drivers such as the CPI, the Australia-United States exchange rate, construction costs and commodity prices.

A cost escalation model was then developed to forecast the likely impact of expected movements of specific input cost drivers on future electricity infrastructure materials costs. SKM used forecast escalation rates for the underlying drivers of network infrastructure plant and equipment costs that included consideration of assumed movements in aluminium, copper, steel, oil and construction costs.

SKM then analysed each of the main items of plant equipment and materials within its database, in order to establish a suitable weighting, by which each of these underlying cost drivers were considered to influence the total price of each completed item.

Application of the assumption

Assumptions regarding the forecast escalation rates for the underlying drivers of network infrastructure costs have been applied to forecast escalation rates at the asset category level. These are in turn used to forecast the material costs that comprise Aurora's capital and operating expenditure for each year of the 2012-17 *Regulatory Control Period*.

Impact of the assumption

As noted by SKM in its report on material costs escalation rates, movements in CPI do not necessarily reflect material costs associated with electricity network projects. The impact of adjusting for material cost escalators, in real terms, will result in both increases and decreases in cost drivers and therefore material cost components of various network assets throughout. This means that in real terms some asset forecasts will increase compared to actual expenditure from the current *Regulatory Control Period* and other asset forecasts will decrease.

7.1.7. Forecasts of utilisation levels

Aurora's RIN defines forecasts of utilisation levels as a key assumption. However Aurora does not use network utilisation to develop its capital expenditure forecasts. Rather demand related expenditure forecasts are developed on the basis of analysis of capacity at the feeder level and forecast demand at that feeder over the forecast period.

Aurora has however provided forecast utilisation levels for its distribution network within the RIN templates required by the AER.

7.1.8. Forecasts of standard asset lives

Aurora's RIN defines forecasts of standard asset lives as a key assumption. However Aurora does not forecast standard asset lives to prepare its capital or operating expenditure forecasts. Capital expenditure for asset replacement cost categories is based on the age and condition of assets, and as such this *Regulatory Proposal* does not discuss assumptions relating to this issue.

Aurora has however provided standard asset lives for the components of its distribution network within the RIN templates required by the AER.

7.1.9. Forecasts of line length

Aurora's RIN defines forecasts of line length as a key assumption. However Aurora does not forecast line length to prepare its capital or operating expenditure forecasts and as such this *Regulatory Proposal* does not discuss assumptions relating to this issue.

7.1.10. Inflation

The *Rules* requires that Aurora's return on capital must be expressed in nominal terms and that Aurora's regulated asset base must be indexed each Regulatory Year to account for the effects of inflation. These requirements mean that Aurora must make assumptions regarding the expected inflation rates for the remainder of the current *Regulatory Control Period* and the forthcoming *Regulatory Control Period*.

Method and information to develop assumption

Aurora has chosen to adopt the AER's preferred method of forecasting CPI. This method adopts the following process:

- plot two years of forecasts from the most recent RBA Monetary Policy Statement; and
- thereafter plot CPI as the RBA inflation target's midpoint of 2.5 percent.

Application of the assumption

This assumption applies in all instances where Aurora has provided forecasts that require adjustments for indexation. At the time of submitting this *Regulatory Proposal* the most recent Monetary Policy published by the RBA was in February 2011.

Impact of the assumption

Inflation assumptions apply to all forecasts requiring adjustments for indexation.

7.2. Capital expenditure assumptions

As discussed above, Aurora has made a range of assumptions that have been applied across the RIN categories and sub-categories of its capital expenditure forecasts. The level of detail provided for each assumption and its impacts is at a detail that ensures its broad application across Aurora's capital RIN expenditure sub-categories.

7.2.1. RIN category – demand related

RIN sub-category – customer initiated

Aurora's capital contribution methodology and the treatment of capital contributions under this methodology will be consistent with Aurora's proposed capital contributions policy due for implementation on 1 July 2012. Revisions to the existing Aurora policy will mean that overall, customers will make a greater contribution to new customer connections works and therefore the effect of this assumption over the 2012-17 *Regulatory Control Period* will be to reduce Aurora's net new customer connections expenditure compared to the current *Regulatory Control Period* (Aurora will not receive a return on these assets into the future).

RIN sub-category – reinforcements

Forecasts are based on consideration of historical demand growth and performance, weather conditions, forecast changes in land use, and on the cost of traditional solutions to network constraints. This means that forecasts are based on the costs of traditional solutions, although Aurora will begin trialling, and implementing where feasible, smarter network technologies.

Demand forecasts are also based on industry, regional, State and Federal Government economic indicators. This means that expenditure forecasts have regard for both historical trends and 2012-17 forecasts.

Demand forecasts have been adjusted to account for the connection (or disconnection) of any known major loads to Aurora's network over the 2012-17 *Regulatory Control Period*. This means that Aurora is able to more accurately forecast this expenditure.

7.2.2. RIN category – non-demand related

RIN sub-category – reliability and quality improvements

RIN sub-category – reliability and quality maintained

Capitalisation procedures will improve over the 2012-17 *Regulatory Control Period* by ensuring that an optimal balance is struck between repair and replacement of assets. Expenditure forecasts reflect amendments to asset replacement decision-making.

Expenditure forecasts are either based on historical replacement rates or determined based on the risk posed by the issue the replacement program is aiming to address. However Aurora will progressively increase condition monitoring and this condition information will be used to better prioritise the risk-based replacement programs. This is intended to drive more efficient investment in infrastructure over the period, although the impact of this improved approach is not yet known with certainty.

Adherence to internal asset replacement standards for each of the asset classes will continue and these standards are detailed in the management plans for each asset class and are appended as attachments to this *Regulatory Proposal*.

Historic failure rates and probabilities of outages (and associated risks) are a valid proxy for the forward rates used to develop reliability and power quality expenditure forecasts. It is assumed that no additional, critical technical risks or failure modes will emerge that have not been considered in preparing forecasts.

As these risks are consistent with the Aurora risk profile, asset managers are comfortable with the risk profile used to plan reliability and power quality improvements and will make no material changes to related policies.

It is assumed that the *Rules* and TEC requirements will remain unchanged during the *Regulatory Control Period*. It is further assumed that the current level of reliability is acceptable to the customer. This assumption means that forecasts only account for expenditure required to meet current standards.

Compliance with national and Tasmanian technical reliability and power quality maintenance standards will be maintained. This means that expenditure in this category will reflect costs driven by the requirement to meet specific regulatory standards.

7.2.3. RIN category – SCADA and network control

A more innovative approach will be adopted in delivering customer outcomes while minimising consequent price increases over the 2012-17 *Regulatory Control Period*, however business cases are not yet at a level that can be justified and these factors have not been included in forecasts. This smarter approach will include the trial and implementation of smarter network technology.

The impact of this assumption is that Aurora's capital expenditure will not reflect any efficiencies that flow from smarter network investment initiatives.

7.2.4. RIN category – non-network

RIN sub-category – IT and communication

An Aurora wide review of all IT systems has been undertaken by an independent expert advisor, Enterprise Architects. This review has resulted in the development of a strategy for IT system deployment within Aurora and is appended to this *Regulatory Proposal*. Expenditure forecasts account for the implementation of this revised strategy during the 2012-17 *Regulatory Control Period*.

RIN sub-category – other

Aurora must comply with a range of safety, health and environmental obligations under both national and Tasmanian legislative and regulatory instruments. It is assumed that there will be no material changes to any of the key instruments with which Aurora must comply, including electrical safety; workplace health and safety; and environmental obligations. This assumption means that forecasts only account for expenditure required to meet current standards.

RIN sub-category – property

Aurora has or will complete a number of property acquisitions and developments during the current *Regulatory Control Period*; such as the consolidation of Network division within Kirksway Place and the redevelopment of the Mornington training centre. This will result in a lessening of property related capital expenditure during the 2012-17 *Regulatory Control Period* and it is assumed that expenditure will fall to historic levels.

RIN sub-category – motor vehicle

RIN sub-category – plant and equipment

It has been assumed that vehicle, plant and equipment standards and practices will be maintained during the 2012-17 *Regulatory Control Period*. This means that expenditure in this category will reflect costs driven by the requirement to meet current practices and standards.

7.3. Operating expenditure assumptions

As discussed above, Aurora has made a range of assumptions that have been applied across the RIN categories and sub-categories of its operating expenditure forecasts. The level of detail provided for each assumption and its impacts is at a detail that ensures its broad application across Aurora's operating RIN expenditure sub-categories.

7.3.1. RIN category – operating costs

RIN sub-category – network divisional management

The GSL Scheme, which requires payments to be made to customers on the basis of the frequency and duration of outages, will continue in its current form. In accordance with clause 6.6.2 of the *Rules*, Aurora will continue to operate under the GSL Scheme issued by OTTER, rather than that developed by the *AER*.

Network division management costs are currently classified by OTTER as prescribed, or regulated, distribution services. The *Rule* requirement to classify distribution services as either standard control, alternative control, negotiated or unregulated will require a re-allocation of network division management costs to these service classifications. Expenditure forecasts will reflect this reclassification and will result in a change in the costs previously associated with this activity.

7.3.2. RIN category – non-network divisional management

RIN sub-category – system operations

Operations of the distribution network are governed by Aurora's internal operating procedures. Aurora has assumed that internal operating standards for the distribution network will continue in their current form and that expenditure in this category will reflect costs driven by the requirement to meet current standards.

RIN sub-category – corporate and shared services costs

Corporate and shared services costs are currently classified by OTTER as prescribed, or regulated, distribution services. The *Rule* requirement to classify distribution services as either standard control, alternative control, negotiated or unregulated will require a re-allocation of corporate and shared services costs to these service classifications. Expenditure forecasts will reflect this reclassification and will result in a change in the costs previously associated with this activity.

RIN sub-category – NEM and contestability related costs

Aurora has assumed that the NECF package will commence as of 1 July 2012 and the final package will not materially deviate from what is proposed at the time of drafting the *Regulatory Proposal*. The impact of the assumptions is that there should be no additional systems and process costs on Aurora during the 2012-17 *Regulatory Control Period* as a result of compliance with NECF requirements.

Aurora has assumed that the Tasmanian Government will introduce a further tranche of retail contestability starting 1 July 2011 (tranche 5A). The impact of the assumptions is that there should be no additional systems and process costs on Aurora during the 2012-17 *Regulatory Control Period* as a result of compliance with tranche 5A requirements other than those already considered.

Aurora understands that the introduction of further tranches of retail contestability or full retail competition within Tasmania is not currently a Government policy and will be considered by the Expert Panel as part of its review. Aurora has assumed that there will be no further tranches of contestability and changes to regulatory and legislative frameworks are not included in forecasts. Any costs could only be passed through to customers if Aurora meets the Rules requirements for a pass through event.

7.3.3. RIN category – maintenance costs

RIN sub-category – routine maintenance

Aurora's maintenance works are governed by individual management plans for each asset class and as such works over the 2012-17 *Regulatory Control Period* will be carried out in accordance with the intervals prescribed within the management plans. These management plans are appended as attachments to this *Regulatory Proposal*.

7.3.4. RIN category – maintenance costs

RIN sub-category – non-routine maintenance

Aurora must comply with a range of safety, health and environmental obligations under both national and Tasmanian legislative and regulatory instruments. It is assumed that there will be no material changes to any of the key instruments with which Aurora must comply, including electrical safety and workplace health and safety obligations, and environmental obligations. This assumption means that forecasts only account for expenditure required to meet current standards.

Historic failure rates and resultant outages are a valid proxy for the forward failures and outages used to develop emergency and unscheduled power system expenditure forecasts. It is assumed that no additional failure modes will emerge that have not been considered in preparing forecasts.

Aurora's vegetation management expenditure is driven by obligations under the *TEC* and the associated compliance activities contained within Aurora's vegetation management plan. It is assumed that there will be no material changes to Aurora's obligations under the *TEC*. This management plan is appended as an attachment to this *Regulatory Proposal*.

Aurora's fire mitigation works are governed by an individual management plan and as such works over the 2012-17 *Regulatory Control Period* will be carried out in accordance with the management plan. This management plan is appended as an attachment to this *Regulatory Proposal*.

The Victorian Bushfires Royal Commission has released a number of recommendations associated with the 'Black Saturday' bushfires. These recommendations may have a future impact on both Aurora's bushfire mitigation and vegetation management practices but are yet to be quantified. Expenditure forecasts are based on current standards and should a change in standards occur during the 2012-17 *Regulatory Control Period* additional costs will be addressed via the *AER*'s cost pass through mechanism

Aurora's connection asset repair activities are governed by an individual management plan and as such works over the 2012-17 *Regulatory Control Period* will be carried out in accordance with the intervals prescribed within the management plan. This management plan is appended as an attachment to this *Regulatory Proposal*.

8. Risk management and asset management framework

8. Risk management and asset management framework

Aurora manages its business risks in accordance with a risk management framework. The framework and supporting policy documents are based on risk management standards and are approved by Aurora's Board.

Risk mastery has been recognised as one of the five elements of Aurora's target culture. The purpose of integrating risk management into the business is to increase the likelihood of achieving Aurora's stated vision and purpose; and provide the basis for risk management within strategic and operational planning and decision-making at all levels across all activities. Aurora's risk management framework is outlined in Figure 25.

Risk management drives virtually all network activities and programs including:

- reliability assessment;
- network augmentation;
- customer connections;
- asset replacement;
- asset operation; and
- asset maintenance.

Risks are assessed according to the Australian Risk Management standard (AS/NZS ISO 31000) and are assessed with reference to the Aurora risk management framework and the potential impacts on:

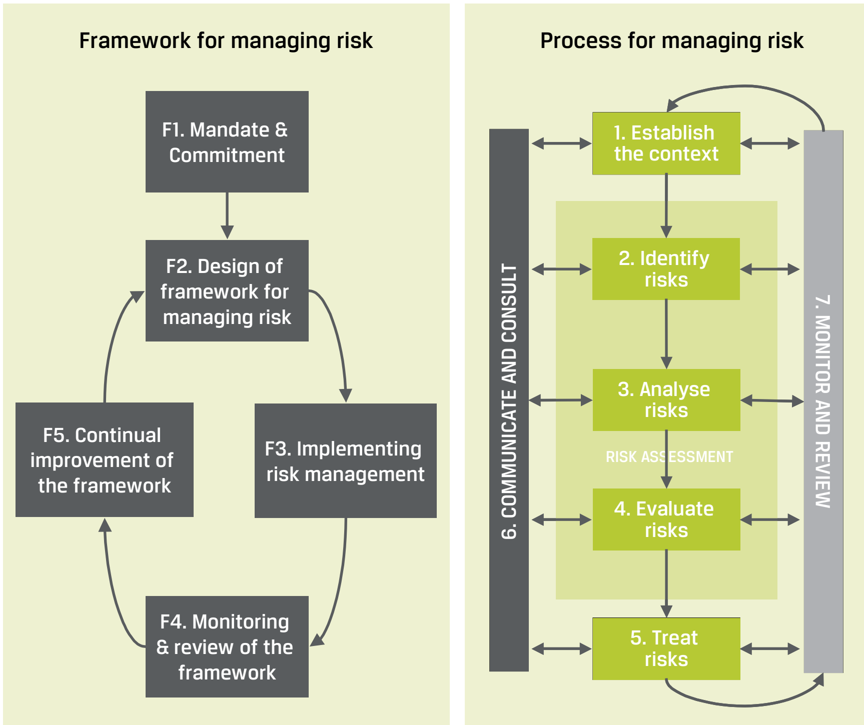
- safety;
- environment;
- reliability;
- system security;
- financial performance;
- legal/compliance; and
- corporate reputation.

Figure 25

Risk management framework

Principles for managing risk

- Creates value
- Integral part of organisational processes
- Part of decision making
- Explicitly addresses uncertainty
- Systematic, structured and timely
- Based on the best available information
- Tailored
- Takes human and cultural factors into account
- Transparent and inclusive
- Dynamic, iterative and responsive to change
- Facilitates continual improvement and enhancement of the organisation



Risk management considerations have resulted in replacement programs for specific asset-types found to pose an identified risk as a result of failure. Risk is the principal driver of replacement priorities for each replacement program. This ensures that individual assets considered the highest risk are managed to mitigate the risk to acceptable levels.

All asset inspection programs have an implicit aim of assessing the asset condition to determine risk. Demand driven augmentations are also based on analysis of the risks to asset, customer supply availability and compliance with technical and regulatory obligations.

Aurora is currently introducing a risk-based approach to optimise work programs to help determine allocations of resources across the various asset management programs and support activities.

The focus of this approach is to ensure that work programs address the highest risk as a priority.

The outcomes of this initiative will be:

- a consistent approach for assessing risk across work programs, allowing for a comparison of risk across these programs;
- assessment criteria are aligned with the business objectives; and
- operational and capital budgets are developed to deliver business objectives in a sustainable manner across work programs.

The tool being developed includes a rating system to determine both the risks and the benefits associated with each project or program to allow project ranking and assist with decision-making and optimising the program of work.

8.1. Disaster management

Aurora's operational priorities in order of importance are:

- ensuring personal safety of both the public and Aurora staff;
- protecting equipment and infrastructure from damage;
- efficient supply restoration – including meeting the communication requirements of customers and other emergency services; and
- keeping the community informed.

Aurora has adopted an Incident Control System (ICS) as its methodology for event management of storms, bushfires or other major incidents on its distribution system. The objectives of this system are to:

- ensure the emergency response is always managed, controlled and co-ordinated across the whole of the affected area to achieve the best possible event management;
- allocate its finite field resources to maximum effect;
- plan during the event, based upon information coming from the field to allow flexibility in response;
- ensure that all those involved understand their role and responsibilities;
- keep communications flowing internally and to customers giving then clearer and more realistic timeframes for power restoration; and
- account and summarise what occurred.

ICS integrates personnel, procedures, facilities, equipment and communications into a common organisational structure. It provides clear delegation of responsibilities to effectively accomplish stated objectives. Further detail regarding the ICS is contained within the Event Response Management Manual[1], which is to be read in conjunction with other Aurora policies. This manual is reviewed twice each year, at the end of November and the end of March. If the system has not been enacted for a period of 12 months, a desktop exercise is run with a debriefing and report.

8.2. Bushfire preparedness

Bushfires initiated by interaction between vegetation and powerlines or asset failure present a considerable risk to Aurora. In the latest Aurora-wide risk assessment the inherent risk of Aurora's assets starting a bushfire was categorised as 'Extreme'. Risk treatment plans and controls currently in place have resulted in a residual categorisation of the risk to 'High'.

Aurora continually reviews processes and procedures to identify and implement additional and refined controls aimed at achieving Aurora's targeted risk appetite of 'Moderate'. Aurora's bushfire preparedness has also taken on added focus as a consequence of the release of the recommendations of the Royal Commission into the 2009 Victorian Bushfires.

The objectives of the Bushfire Mitigation Management Strategy are to:

- control vegetation interaction with the distribution network in compliance with *TEC* Chapter 8A;
- implement targeted programs to minimise the possibility of distribution network assets starting fires;
- implement an annual bushfire mitigation program to ensure prudent controls are in place for each fire season; and
- implement prudent work practices associated with the operation of the distribution network, and field activities undertaken by Aurora and its service providers.

Knowledge of the causes, incidence and environment associated with serious fires enables programs of awareness, inspection and prevention to be established and targets or rules to be set that reflect a proper focus on the causes of fire ignition that are judged to be the greatest risk to the public and the business.

A considerable amount of investigation has been undertaken by the industry to determine these causes and enable electricity utilities to determine preventative actions to be taken.

The main causes of fire ignition from electricity assets are known to be:

- failure of line hardware (electrical and mechanical);
- failure or malfunction of network devices (such as surge arresters and expulsion drop out (EDO) fuses);
- clashing conductors;
- bird or animal contact with electricity assets;
- surface contamination of insulators combined with moisture, resulting in electrical tracking (pole fires);
- failure of poles;
- contact between vegetation and the electricity network; and
- defective private overhead electric lines (POELs).

These mechanisms of fire causes form the basis of Aurora's preventative works programs and pre-summer work programs. Further detail regarding these programs is contained within Aurora's Management Strategy Bushfire Mitigation, appended as an attachment to this Regulatory Proposal..

8.3. Contingency planning

In the event of large-scale outages, the Operations team within the Operational Technology and Real Time Management group, may have difficulty in restoring the outage in a timely manner due to the complexity and varying nature of system loads and conditions, meaning contingency planning prior to events occurring critical.

To assist in the development of contingency plans, Aurora has created a software tool, CONAN, that quickly and accurately analyses the distribution network following outages and identifies possible switching operations that may be performed to restore supply without exceeding prescribed voltage or rating limits.

The tool leverages off Aurora's existing investment in network modules in the DINIS Network Analysis Package, the DINIS API Module, and the Feeder Loads Reporting System (FLRS). The software carries out load flows based on user-entered feeder outages and loads.

Contingency plans have been created for each of the major distribution substations around the State by means of a contingency plan template. Each contingency plan has been developed to simulate as many major outage scenarios as practically possible. These plans include relevant information pertaining to the infrastructure and critical customers affected, and advise of the appropriate switching operations to be made to restore as many customers as possible. Contingency plans are reviewed annually and updated as necessary.

The tool can also be used in real time to provide a guide on the load transfer capability of adjacent feeders and substations within outage areas before set limits are violated. More information can be found in the Contingency Plan Register[2] and the Contingency Plan Review Procedure[3].

Ad hoc contingency plans are also produced upon notification of an increased risk of outage due to planned work that affects Aurora's N-1 conditions. These notifications come from internal or external sources, such as a transmission line outage notification from Transend.

As part of its general contingency capability, Aurora has vendor stock arrangements for the highest volume products such as poles and pole-mounted transformers, plus an amount of non-inventory spare plant available for use in the event of failure of primary plant.

1 Aurora Energy's Distribution System Event Response Manual, v 2.0, describes Aurora Energy's adoption of the Incident Control System as its methodology for the management of storm or other incidents on Aurora's distribution system.

2 The Register documents all Aurora Operation Centre contingency plans in its appendices.

3 The Review Register records the date each operating officer has reviewed the most recent version of each contingency plan completed. .

Aurora also employs a 24 hour, seven day call out rosters for fault response personnel in all areas of the State to minimise disruption during out-of-hours emergencies.

Aurora also has its own mobile generating unit, as well as arrangements with companies that can provide stand-alone generating units, to reduce the impact on customers when network items are taken out of service for maintenance or network expansion. These units can also be used to reduce the impact of unplanned outages associated with critical primary plant. Use of these units is factored into contingency plans.

Aurora has a large pool of skilled personnel to support contingency plans. In addition, Aurora has relationships with contractors to call on to respond effectively to events.

8.4. System security levels

It should be noted that the majority of distribution network supply type substations are owned and operated by Transend with only those substations in parts of Hobart and in some rural areas being the responsibility of Aurora.

The security status of those substations under the control of Transend is managed through the Transend governance and load transfers; and other measures are conducted through the joint planning process between Aurora and Transend.

Zone substation summary

Aurora presently has 16 zone substations, with a further two under construction. During the current *Regulatory Control Period* one zone substation has been decommissioned. For the 2012-17 *Regulatory Control Period* no further zone substations are planned to be installed.

Of the current 16 zone substations, 10 are considered major (over 10 MVA) and six minor (under 10 MVA). None of these zone substations is solely for the supply of a specific customer.

There is adequate capacity to meet the current maximum demand, under normal summer or winter operating conditions, at 11 of the 16 zone substations. A breakdown can be seen in Table 21.

Of the five zone substations which are at risk from a contingent event:

- one is marginally over nominal transformation ratings, but within emergency ratings;
- two have either a sub-transmission or distribution feeder supply with no alternative supply capability. Of these, one zone substation supplies a major load with a relatively small distribution load; and
- two have adequate alternate supply capabilities that will take less than two hours to restore.

Over the 2012-17 *Regulatory Control Period* the number of zone substations will increase to 17, with two additional zone substations and one zone substation being decommissioned.

Of the identified at risk zone substations:

- one supplied by a single distribution feeder will be decommissioned, with reconfigurations conducted to minimise the system impact of a feeder interruption;
- two will have load reduced following the commissioning of one of the two additional substations;
- two will still be at security risk, however can be managed by load transfers; and
- one will still be at risk due to its single sub-transmission circuit.

The substation security risk data is portrayed in Table 22.

Table 21

Security level status 2010-11

	Substations - first contingent event				Total
Substation type	Maximum demand within supply capability	Maximum demand above supply capability - restoration <= 30 mins	Maximum demand above supply capability - restoration <= 120 mins	Maximum demand above supply capability - restoration > 120 mins	
Major	7	0	2	1[1]	10
Minor	4	1[2]	0	1[3]	6

Notes: 1 Substation has single sub-transmission circuit.
2 Loading within emergency rating.
3 Substation is supplied off single 22 kV distribution feeder.

Table 22

Security level status 2016-17

	Substations - first contingent event				Total
Substation type	Maximum demand within supply capability	Maximum demand above supply capability - restoration <= 30 mins	Maximum demand above supply capability - restoration <= 120 mins	Maximum demand above supply capability - restoration > 120 mins	
Major	9	0	2[1]	1[2]	12
Minor	4	1[3]	0	0	5

Notes: 1 Can be managed by load transfers.
2 Substation has single sub-transmission circuit.
3 Loading within emergency rating plus transfers.

High voltage feeder summary

Table 23 provides a summary of the results from the 2010 Feeder Load study in which all feeders were reviewed with their loading and compared to Aurora's planning criteria.

Table 23

Distribution feeder security status 2010

Category	Number	%
Total feeders	369	100
Capacity limitation	26	7

Note: Does not include sub-transmission feeders

The term limitation refers to the non-compliance with the feeder planning criteria. The majority of the 26 limitations are related to feeder maximum demand loads exceeding the '3 into 2' target security level criterion applicable to urban or meshed networks, rather than the individual feeder conductor ratings being exceeded under normal operating conditions.

Table 24 projects the security levels in 2016-17 and shows the expected non-compliance against the planning criteria.

It should be noted that in this table future substation feeders and proposed feeder numbers are included. Arising from the connection of these new feeders, capacity limitations on associated or interconnecting feeders are planned to maintain the present level of feeder limitations (26), albeit on an altered feeder set.

Table 24

Distribution feeder security status 2016-17

Category	Number	%
Total feeders	402[1]	100
Capacity limitation	26[2]	6

Notes: 1 Includes future feeders
2 Includes limitation reductions from future feeders
Does not include sub-transmission feeders

Capacity limitation on 26 feeders (6 percent) indicates that Aurora is accepting the same order of risk as it is at present.

Low voltage feeder summary

Aurora does not assess the security status for distribution substations (nominally 1,500 kVA and below).

9. Commencement and length of Regulatory Control Period

9. Commencement and length of Regulatory Control Period

This will be Aurora's first *Regulatory Proposal* to the AER and Aurora's current *Regulatory Control Period* ceases on 30 June 2012.

Clause 6.3.2(b) of the *Rules* requires that a *Regulatory Control Period* must not be less than 5 *Regulatory Years*. Clause 6.12.1(2)(ii) further requires that a Distribution Determination is predicated on a decision by the AER on the commencement and length of the *Regulatory Control Period* and clause 6.12.3(e) requires the AER to approve a proposed *Regulatory Control Period* if the proposed period consists of 5 *Regulatory Years*.

Aurora proposes that the *Regulatory Control Period* commence on 1 July 2012 and conclude on 30 June 2017, meaning that the term of Aurora's *Regulatory Control Period* is 5 years, and is consistent with the requirements of the *Rules* and should be approved by the AER.

10. Forecasts

10. Forecasts

This chapter sets out Aurora's high level methodology for the development of its forecasts for load growth or demand forecasts (typically MW), energy consumption (GWh) and customer numbers for the distribution network for the forthcoming *Regulatory Control Period*.

10.1. Demand forecasts

This section of Aurora's *Regulatory Proposal* sets out Aurora's high level methodology for the development of its forecasts for load growth or demand forecasts (typically MW) for the distribution network for a 10 year period.

10.1.1. Load forecast methodology

Aurora's underlying approach is to project load growth forward at each connection site at a rate that is consistent with recent history. These spatial forecasts are then aggregated together, using diversity factors, to a system level forecast (bottom-up). This bottom-up forecast is then compared to, and reconciled with, a forecast at the system level (top-down).

The system level forecast is taken from that prepared independently by the National Institute of Economic and Industry Research (NIEIR) for Transend.

Spatial forecasts, in MW and MVA, are prepared for the individual connection sites.

Demand forecasts are prepared for both summer (December-February) and winter (June-August) periods.

10.1.2. Data management

Production of the forecasts requires data series that are quite specific. Aurora undertakes data 'cleaning' in the context that:

- adjustments are made for loads that have been permanently switched from one point to another; and
- validation is undertaken to ensure that the data is reasonably free of problems like missing observations and other errors.

For the purposes of the modelling Aurora utilises, where possible, a daily time series for the summer and winter periods for each of the connection sites, going back a minimum of five years (denoted in MW).

Aurora also details any permanent transfers between substations both historically and for the forecast period. These are required to correct for any past and expected discontinuities in the dataset, which if not accounted for, may result in biased forecasts. Past details of major block loads and details of forecast block loads that will cause a discontinuity in the time series are also required.

The actual peaks are adjusted by any permanent transfers and block loads before any forecasts are derived. In addition to block loads and permanent transfers, details of any demand side management (DSM) and irrigation loads which will affect the peak in each historical forecast period are also accounted for. Adjustments are then made to the underlying time series before any time trend regressions or growth factors are applied.

Embedded generation is another factor that is accounted for. Aurora believes that the best approach is to include embedded generation in the original daily time series for each substation (which is used for weather correction) but if it is outside its normal operational mode to adjust the contribution of any embedded generation from the peak in each season before extrapolating into the forecast period.

10.1.3. Weather correction

Aurora weather corrects the data to the 10 percent and 50 percent probability of exceedence levels (POE).

Weather correction in demand forecasting

The random nature of weather means that any comparison of historical electricity loads over time requires these loads to be adjusted to standardise weather conditions. Typically, actual demand is standardised to either, or both, of 10 percent and 50 percent POE. The 50 percent (10 percent) POE demand level is the annual maximum level that, on average, would be met or exceeded 50 percent (10 percent) of the time. It can be thought of as the maximum demand that would be observed or exceeded once every two (10) years on average.

As the intent of load forecasting is to forecast maximum demand at a given POE level, any trend relationships of spatial maximum demand that are based on non-weather normalised data could be susceptible to bias, particularly if the historical data contains a number of extreme seasons. It is imperative that any demand forecasting methodology incorporates an appropriate form of weather normalisation or correction. This is true at all levels of the network, from the feeder to the system level.

Aurora's approach to weather correction

Aurora's approach to weather correction involves estimating a regression between the daily maximum demand (MD) and a selection of weather variables from a suitable weather station.

Those substations that tend to peak in the morning will have coefficients that are weighted more towards the daily minimum, whereas those that peak in the afternoons will have a higher temperature sensitivity for the daily maximum.

The temperature sensitivities are calculated for each year in the time series. For example, to temperature-correct five winter peaks from 2006, Aurora will estimate five separate regressions between the daily MD and temperature/weather variables for each winter season from 2006 onwards.

Individual temperature sensitivities are calculated for each of Aurora's connection sites. Before estimating the temperature sensitivity coefficients, it is important to note that Aurora removes weekends from the time series, as these almost never correspond to seasonal peaks. In the case of summer, in addition to removing the weekends, Aurora removes the Christmas/New Year period, which usually corresponds to lower demand.

The actual season peak is then adjusted along the regression line towards a long run weighted average temperature which corresponds to the 10 percent POE and 50 percent POE weighted average temperature. The weightings are determined by the coefficients on the daily maximum and daily minimum temperature variables from the temperature sensitivity regressions.

10.1.4. Adjusting for significant block loads, permanent transfers and other factors

Before applying any form of regression analysis or growth factor to historical weather corrected peak demands, these are adjusted for transfers to and from the substation as well as significant block loads that comprise a large proportion of the loads at the specific connection site. The effects of transfers and large block loads are removed from the historical data series before any trends are fitted or growth rates are determined. These are later added back to the forecasts.

Forecasts are also adjusted for predicted transfers and large block loads expected to arise during the forecast period. Expected block loads are added to the forecast only if they stand out as unusual or significant when compared to the history of the connection site in question. If they are not unusual, the underlying trend growth estimated by fitting linear trend through the historical data will incorporate these types of loads.

As a general rule, only loads that are greater than 5 percent of the total load at a connection site are added onto the forecast. Loads smaller than the threshold are assumed to be captured by the underlying trend in the time series.

If unusual or significant block loads are expected, their size and the likelihood that they will materialise is estimated and the product of these two factors is added to the forecast at the appropriate time.

The size of spot loads is estimated in terms of contribution to load at the time of connection site peak demand. Some types of load may be at full demand when the system peaks, others may not.

The same approach is used for expected reduction in load as a result of any demand side management projects (treated as negative loads).

In addition to adjustments for block loads and permanent transfers, it is also necessary to make adjustments for irrigation loads and the effect of any embedded generation operating at the time of peak demand for each connection site.

10.1.5. Developing the forecasts

Once data has been temperature/weather corrected and adjusted for large block loads and permanent transfers, demand forecasts are produced.

The basic approach is to extrapolate from recent history using linear time trends (over varying time frames) or applying growth rates based on historical behaviour to the most recent temperature-corrected observation.

This methodology is applied to non-coincident peak demands for each substation. Diversity factors are applied to the aggregated forecasts to derive an overall system demand for each season in the forecast period.

Reconciliation with system level forecasts (top-down)

The forecasts are then reconciled with the medium economic growth scenario of the independently produced system level forecast (NIEIR) by applying a proportional adjustment to each of the individual substations so that the sum of the coincident demands corresponds to the independent system demand forecast in each year of the forecast period.

The adjusted coincident substation forecasts are converted back to non-coincident peaks using the same diversity factor as applied previously. The diversity factors applied during the forecast period will be related to historical behaviour, generally an average of the last three or five years.

Reconciliation with an independently produced system level forecast has the advantage of allowing the methodology to incorporate the impacts of broader macroeconomic and demographic aggregates, as well as the impacts of new policy initiatives, which are better modelled at the system level. System level data is also smoother and more amenable to the fitting of econometric models that can be used to generate more accurate system level forecasts.

Internal review of forecasts

The derived forecasts are reviewed by an Aurora person with experience of the relevant connection site. This person makes sure that the forecast 'fits' with the site in question and uses engineering judgement to make adjustments where it does not. In particular, the use of old data creates a tendency for forecasts to 'miss' changes in growth rates. For example:

- the forecasts may be too low in areas which are about to become (or have recently become) high growth areas;
- conversely, the forecasts may be too high in areas that have recently reached 'maturity'; or
- growth in industrial load will likely reflect growth in Tasmania's gross state product (GSP). If GSP is expected to accelerate (decelerate) over the forecast period, the forecasts will tend to under (over) estimate actual growth.

Any changes that are made through this process are recorded with supporting evidence. These records form part of the documentation of the forecasts.

10.1.6. Transend system level forecast

The 2010 forecasts of summer and winter maximum demands for Tasmania were developed by NIEIR for Transend using econometric regression equations based on Transend metering data. In broad terms, these relationships (equations) relate the ratio of maximum demands, to energy, to average temperature, at system maximum demand (MD).

The MD forecast is linked to the energy forecast to ensure consistency between the energy and the demand projections.

The energy projections for Tasmania reflect the sectoral composition of GSP growth, as well as the impact of changes in real electricity prices and other policy drivers of the energy projections. The load factor equation effectively means the forecast MDs for Tasmania indirectly reflect the impact of GSP and real electricity price changes.

The MD equation also includes Tasmanian GSP as an independent explanatory variable. Its sign suggests that the faster the growth in GSP, the faster the growth in the ratio of the winter MD to total energy.

System maximum demand is the maximum half hour average Tasmanian system requirement at generator terminals. This demand for the relevant half hour, expressed as an average power comprises:

- total Tasmanian end-use sales;
- power used in power stations; and
- transmission and distribution losses;

excluding:

- buyback (supplying sales) from cogeneration/generation embedded in the distribution network; and
- own use, supplying load directly from cogeneration/generation embedded in the distribution network (i.e. not drawn from network and not sales).

A detailed analysis of ambient temperature data for Tasmania was undertaken by NIEIR in order to estimate the ranges of future winter and summer temperatures. For each medium, high and low forecast, the following three temperature based forecasts are developed:

- 10th percentile: temperature met once in every 10 years (10% POE);
- 50th percentile: temperature met once in every two years (50% POE); and
- 90th percentile: temperature met nine out of 10 years (90% POE).

Considering the variations in the input variables of the forecast and the temperature variations, NIEIR produces nine different generation forecasts (i.e. 10%, 50%, and 90% POE values for each of high, medium, and low economic growth scenarios).

The relationships between Tasmanian MDs, energy and weather conditions were estimated excluding the impact of the major industrial customers that are assumed to be weather/temperature insensitive. The major industrial customers and other customers (i.e. retail and minor industrial customers) are examined separately. The major industrial customers that are directly connected to the transmission network are excluded from the system level forecast applied to the distribution network.

10.1.7. Forecast results

Aurora's forecast is based on a medium economic growth scenario with a 50 percent and 10 percent POE.

10.1.8. Demand side management

Aurora is proposing a range of demand management initiatives for the forthcoming *Regulatory Control Period* as outlined in chapter 26 of this *Regulatory Proposal*.

As Aurora is yet to finalise these proposals and subsequently gain approval from the AER, the impact of those programs has not been included in this forecast.

10.1.9. Embedded generation

As noted in the methodology, the demand forecast includes embedded generation operating in its normal mode at the time of peak demand.

Currently there are 10 individual embedded generators (greater than 500 kW rating) connected to the distribution system with a total generation capacity of approximately 24 MW. Under normal operation, the total generation into the distribution system at time of summer and winter maximum demand is in the order of 10 MW.

In addition there are approximately 1,800 photo voltaic (PV) systems currently connected to the distribution network, with an average rating of 1.1 kW. Due to the nature of operation of these units (only generate during hours of daylight) and their dispersion around the distribution network, they do not have a material effect on the winter peak demand, and only limited effect on the summer peak demand.

10.1.10. System forecast

Figure 26 and Figure 27 present the 10 year distribution system forecast of maximum demand for the summer and winter periods.

Figure 26

Forecast Summer Demand

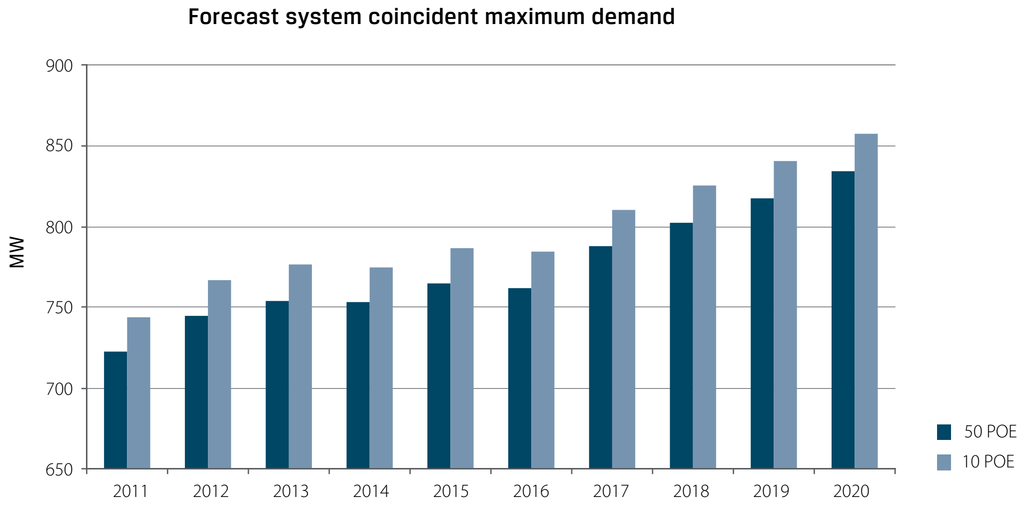
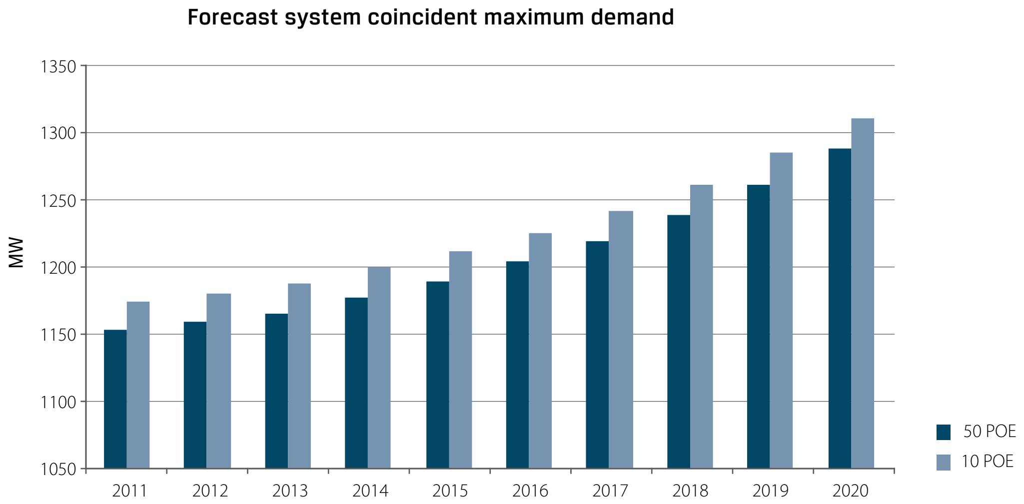


Figure 27

Forecast Winter Demand



10.2. Energy consumption forecasts

This section of Aurora's *Regulatory Proposal* sets out Aurora's high level methodology for the development of its forecasts for energy consumption (GWh) for the distribution network for the forthcoming *Regulatory Control Period*.

10.2.1. Consumption forecast methodology

Aurora's energy consumption forecasts were prepared by Aurora and reviewed by ACIL Tasman on the basis of analysis and assumptions made on a range of factors used to develop Aurora's demand forecasts. These factors included national and Tasmanian considerations.

The purpose and underlying methodology of the consumption model is to project energy consumption forecasts forward at a rate that is consistent with recent history for each tariff class at an aggregated group level. Forecasts include the use of a growth factor that has been constructed to account for weather (summer and winter) and economic factors that are applied to the aggregated tariff class for low, medium and high outlooks.

Aurora's methodology uses the demand growth forecasts for summer and winter prepared by NIEIR to project the estimated energy for 2011-12 for the six customer classes of: residential, small business (LV), medium business (LV), large commercial (HV), irrigation and unmetered supplies (including public lighting).

ACIL Tasman has produced a maximum demand (MD) forecast model for Aurora which utilised forecasts of weather and economic factors for Tasmania based on the NIEIR econometric regression equations that were used for Transend's Pricing Determination in 2009. ACIL Tasman's MD model incorporates NIEIR's normalisation approach to weather and economic factors.

The random nature of weather means that any comparison of historical energy loads over time requires these loads to be adjusted to standardise weather conditions and utilises 40 year average forecasts to determine the sensitivities.

Economic data incorporates gross state product growth as well as the impact of changes in real electricity prices and other policy drives of the energy projections.

The aggregate tariff forecast utilises NIEIR approach to determining the POE levels.

As the intent of load forecasting is to forecast consumption at a given POE level, any trend relationships of spatial consumption load that are based on non-weather normalised data could be susceptible to bias, particularly if the historical data contains a number of extreme seasons. It is imperative that any consumption forecasting methodology incorporates an appropriate form of weather normalisation or correction.

10.2.2. Developing the forecasts

Tariff classes have been aggregated to ensure forecasts provide a high level outcome in establishing trending and to minimise any effects of small customer numbers within individual tariff classes. Historical energy data by customer class has been derived by aggregating individual tariff classes. This aggregation has been provided for the period from 2002-03 to 2009-10 and only includes those customers connected to Aurora's distribution network. The aggregated data does not include load connected directly to Transend's transmission network such as Rio Tinto's Bell Bay aluminium smelter.

Monthly energy consumption comparisons over the past four years show very consistent results, with a monthly range generally less than 35 GWh. Aurora's distribution network has a winter peak demand in July and the maximum monthly energy use in each year also occurs in July.

While energy consumption for 2009-10 was below the trend line, lower consumption has continued for the 2010-11 year (1.3 percent lower than 2009-10) with an annual estimate of 4,455 GWh. This lower level of consumption was last achieved in the 2007-08 year. This lower energy consumption reflects moderate weather conditions, particularly during winter when maximum demand and energy use occurs in Tasmania.

2011-12 estimate

Aurora has estimated energy consumption for 2011-12 to be 4,583 GWh. This estimate is relevant as the energy forecast to 2016-17 uses the 2011-12 estimate as the Base Year.

Aurora's estimate for 2011-12 is 2.88 percent higher than for 2010-11. However, when compared to 2009-10, the annual increase reduces to 0.77 percent per annum and when compared to the historical average growth of 1.18 percent is less than the long term trend line from 2002-03.

2012-17 forecast

Starting with the 2011-12 estimated data, an energy forecast has been developed for each customer class for medium, high and low growth cases based on the 50 percent POE level using growth rates from previous work by NIEIR on demand growth.

The respective winter and summer annual demand growth rates for each case for Aurora's distribution network were utilised as the basis for these forecasts. The average growth rate of 1.07 percent for the medium case, averaged over summer and winter forecasts, is comparable to the historical growth rate of 1.18 percent.

While AEMO's Tasmanian energy forecast is considerably lower, with an average growth of 0.46 percent for the forecast period, Aurora's network only supplies around 40 percent of total State consumption, with the balance of energy supplied directly via Transend's transmission network. State system consumption is approximately 11,500 GWh and if the non-Aurora supplied load has little or no growth, then the effective load for the Aurora-supplied load increases to 1.16 percent based on the AEMO's forecast for Tasmania.

10.2.3. Forecast results

For each case, Aurora has used the annual winter NIEIR demand growth rate to produce an energy forecast for the following customer classes:

- residential;
- small business (LV); and
- medium business (LV).

The average growth rate over the forecast period for the medium growth case is 0.99 percent. The high growth case is 2.30 percent and the low growth case is 0.41 percent.

No growth is forecast for Large Business (HV) and the 2011-12 estimate of 839 GWh is constant over the forecast period.

Growth for irrigation is forecast using the average annual summer NIEIR growth rate of 1.14 percent, using the rationale that most of the demand for water pumping occurs during summer.

Growth of 1.57 percent for unmetered supplies is forecast based on internal analysis by Aurora.

System and customer class forecasts

Figure 28 and Figure 29 present the 10 year energy consumption forecast for the distribution system and each customer class for the medium case.

Figure 28

Forecast distribution energy consumption

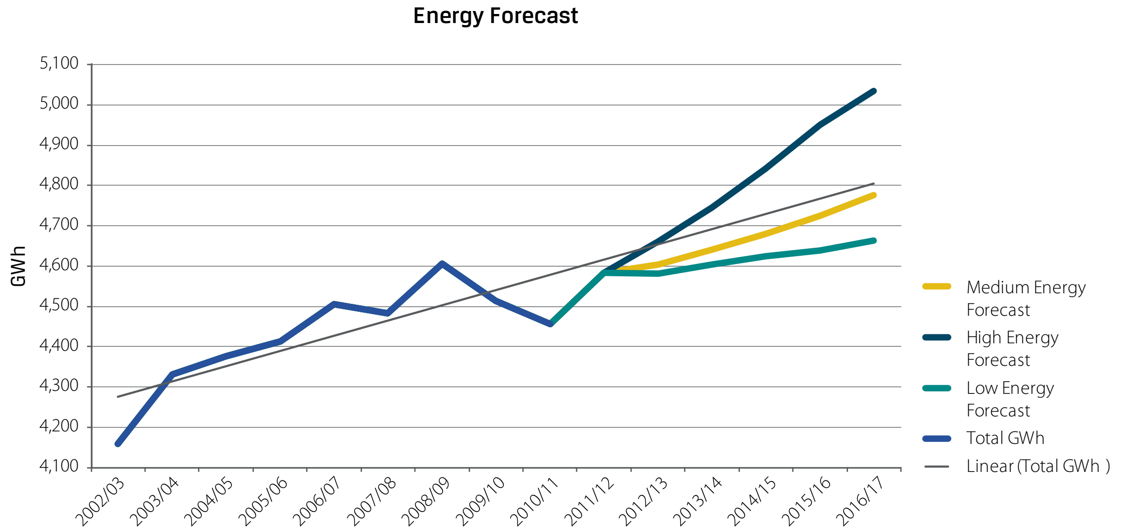
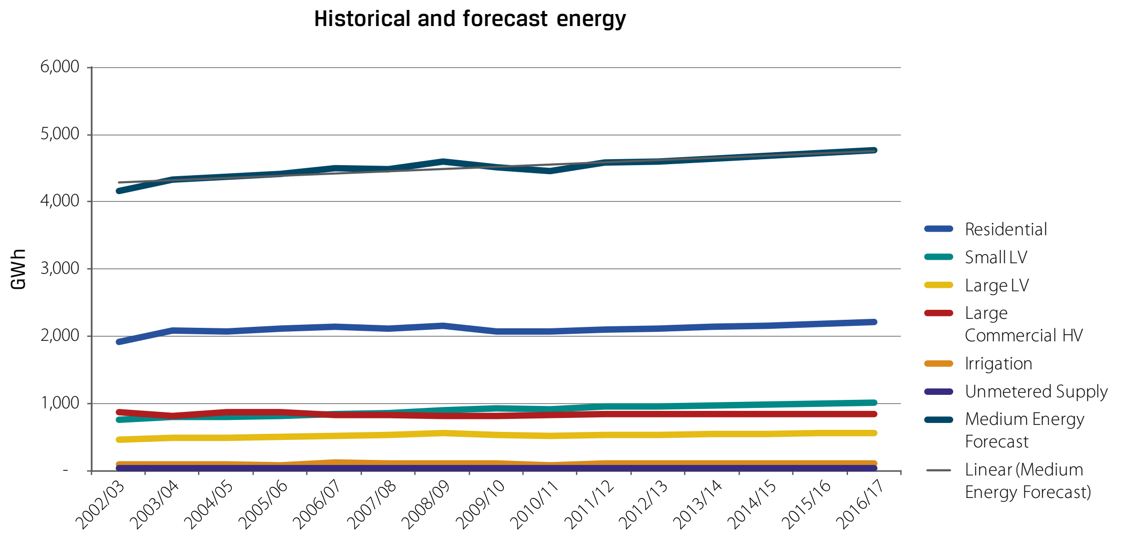


Figure 29

Forecast customer class energy consumption



10.2.4. ACIL Tasman review

ACIL Tasman has reviewed Aurora's adopted methodology and considers that the correlation between demand and energy consumption is weak and that each customer class has underlying drivers that create different growth factors. ACIL Tasman has recommended that Aurora undertake a regression-based approach using credible econometric data (if available), including population growth (residential customers) and gross state product (small and medium business customers), as supplied by suitable economic forecasters.

ACIL Tasman considers this particularly relevant as energy consumption for the past two years has been less than the historical trend and it is unclear whether this is due to either price or demand (or both) impacts.

In light of the recommendations made by ACIL Tasman, Aurora has commissioned ACIL Tasman to undertake further analysis of expected consumption forecasts. Unfortunately this report was not available to Aurora at the time of submitting this *Regulatory Proposal* and Aurora has utilised the energy forecasts derived under Aurora's original methodology. Aurora will make the amended ACIL Tasman report available to the AER once it is received.

Should the amended ACIL Tasman methodology result in changes to Aurora's energy consumption forecasts Aurora will address those changes in its response to the AER's draft determination.

10.3. Customer number forecasts

This section of Aurora's *Regulatory Proposal* sets out Aurora's high level methodology for the development of its forecasts for customer numbers for the distribution network for the forthcoming *Regulatory Control Period*.

10.3.1. Customer forecast methodology

Aurora's forecast of customer numbers for the period 2011-17 has been prepared by ACIL Tasman. ACIL Tasman has produced forecasts of new customer connections for each of the following groups or customer classes:

- residential connections;
- commercial connections;
- irrigator connections; and
- residential subdivisions (number of lots).

ACIL Tasman has produced disaggregated forecasts for each customer class across the three distinct regions of:

- north;
- north west; and
- south.

New residential and commercial customer connections are further split between overhead and underground connections.

Forecasts do not include new connections that require only a simple service connection and this is true for all customer classes.

10.3.2. Developing the forecasts

An econometric methodology has been applied by ACIL Tasman to forecast new customer connections. This approach requires the estimation and testing of statistical relationships between the number of new connections and the underlying drivers that influence the number of new connections.

Residential and commercial connections

The most obvious driver for new residential and commercial connections is the number of new buildings. ACIL Tasman has utilised the ABS Building Approvals Series[1] and Building Activity Series[2] for Tasmania as a proxy for the level of building activity. Both series show a steady increase in the number of annual residential dwelling approvals or commencements with the exception of a sharp fall in the 2005-06 year.

The econometric approach utilised by ACIL Tasman entails the establishment of a relationship between the number of new connections and building activity. This relationship is used to forecast new connections based upon projections of building activity. The ABS does not however produce a projection for building approvals or activity.

The Housing Industry Association (HIA) is one potential source of residential construction activity forecasts. The HIA model produces forecasts for new housing, renovations, non-residential buildings and engineering construction. The HIA has indicated that its forecasting model takes account of the following factors:

- economic growth;
- interest rates;
- employment growth;
- consumer confidence;
- level of oversupply, or pent-up demand for housing;
- interstate and overseas population movements;
- household formation; and
- land availability.

Unfortunately the HIA forecasts are for only two years.

ACIL Tasman have also utilised forecasts provided by the Construction Forecasting Council (CFC). A key advantage of the CFC forecast is that they extend beyond five years. The CFC provides:

- regular short and long term forecasts of the construction and property sectors;
- profiles of national construction activity for major non-residential building and engineering projects across Australia; and
- analysis of the factors driving supply and demand and economic scenarios that underpin the forecasts and sensitivity analysis.

CFC forecasts distinguish 20 categories of construction activity in each State and Territory. The forecasts take into account current (and expected) economic fundamentals along with detailed current and forthcoming activity data published by the ABS and Reed Data Construction, combined with industry intelligence from CFC members.

1 ABS: Catalogue number 8731.0.
2 ABS: Catalogue number 8752.0.

Irrigation connections

ACIL Tasman examined a range of explanatory variables to forecast the number of new irrigators connected to the Aurora network. ACIL Tasman considered historical time series of irrigation activity from the ABS publication Water use on Australian Farms[3], and looked for any statistical correlations that might exist between the number of new irrigation connections and changes in the total area of irrigated land and the volume of water applied. ACIL Tasman was not able to identify any statistically significant correlations. ACIL Tasman has therefore utilised an historical time trend for the number of new irrigation connections due to the unavailability of any significant independent statistical reports.

Regional disaggregation

ACIL Tasman has utilised econometric models relating new connections to real building construction activity and the CFC forecasts to generate forecasts at the Tasmania level for both new residential and commercial connections. Conversely, in the case of irrigation, a simple time trend is applied.

ACIL Tasman has chosen to apply a continuation of the historical trend in the share of total connections across each region in order to disaggregate the forecasts generated across the whole of Tasmania into three separate geographical regions. This was done by estimating a time trend regression for the share of total connections within each region for each of the customer types. These are then extrapolated into the future based on the time trend regression and these forecast shares are used to allocate the total forecast customer numbers across each of the three regions.

Allocation between overhead and underground connections

The split between the number of underground and overhead connections for new commercial and residential connections is determined by estimating separate time trend regressions of the proportion of new connections that are overhead. These regressions are undertaken for each of the three regions. Based on these trends the proportion of overhead versus underground connections for each region is projected into the forecast period.

10.3.3. Developing the forecasts

Output from the estimated statistical models forms the basis of the forecasts that have been prepared by ACIL Tasman.

In the case of new residential connections (including subdivisions) a regression was estimated by ACIL Tasman, with the real value of residential construction used as an explanatory variable. For commercial connections, the real value of non-residential construction was the main explanatory variable.

The new connection forecasts were then generated by applying the forecasts of residential and non-residential construction published by the CFC to the fitted models.

In the case of irrigation, the main driving variable was the historical time trend.

Additional terms were added to the models by ACIL Tasman to capture the dynamic behaviour of the forecast time series.

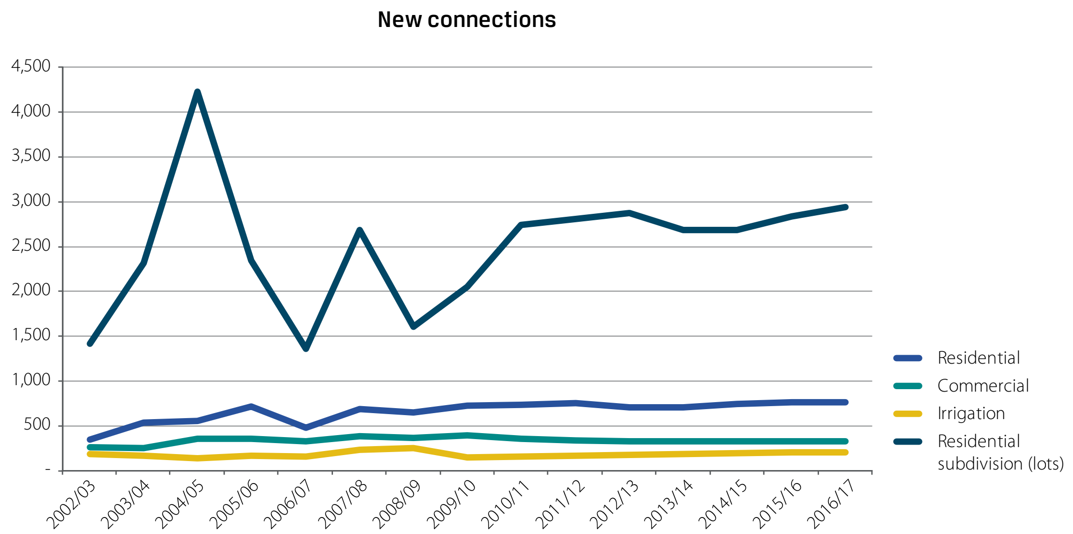
10.3.4. Forecast results

Figure 30 shows the customer forecast for residential, commercial, irrigation and residential subdivision (lots) for the forthcoming *Regulatory Control Period*.

3 ABS: Catalogue number 4618.0.

Figure 30

Forecast customer numbers

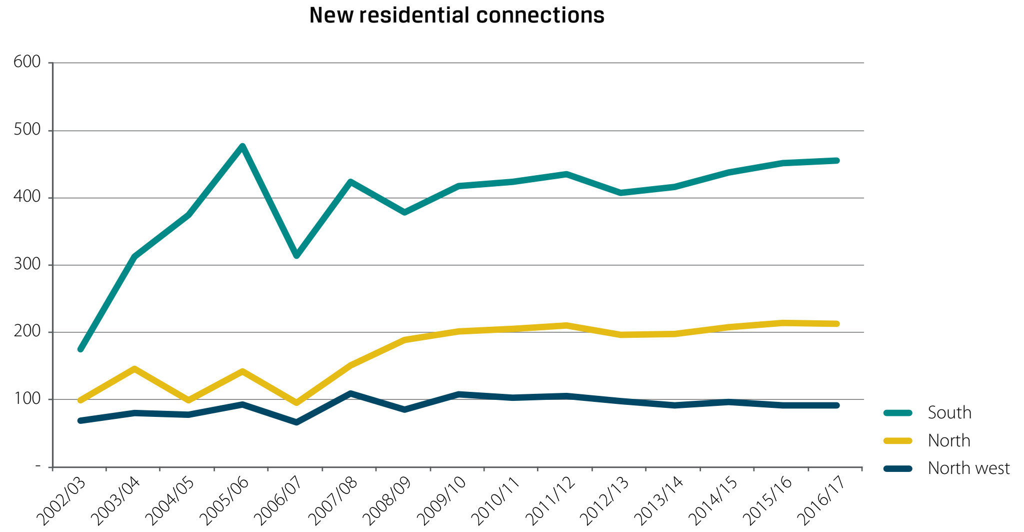


Residential customers

Figure 31 shows the residential customer forecast for the north west, north and south regions for the forthcoming *Regulatory Control Period*.

Figure 31

Forecast residential customer number

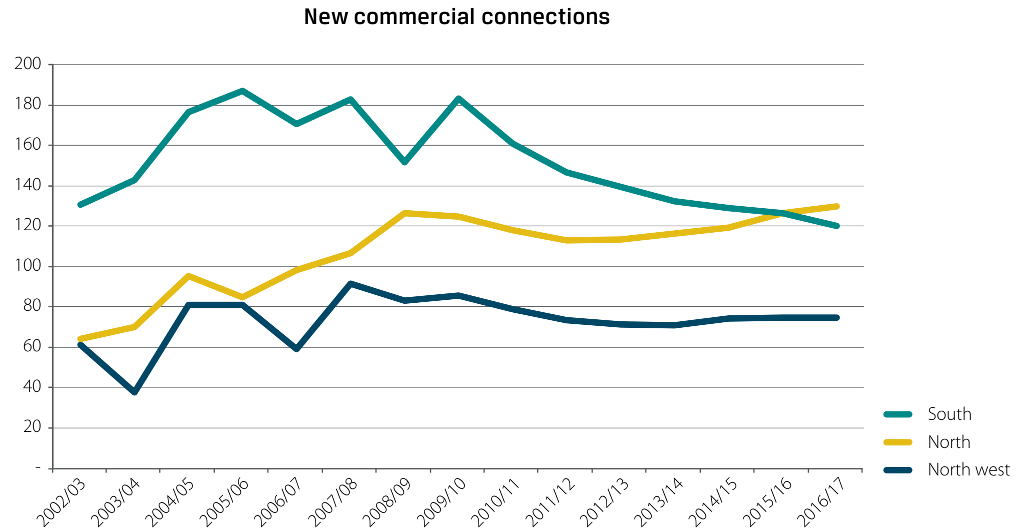


Commercial customers

Figure 32 shows the commercial customer forecast for the north west, north and south regions for the forthcoming *Regulatory Control Period*.

Figure 32

Forecast commercial customer number

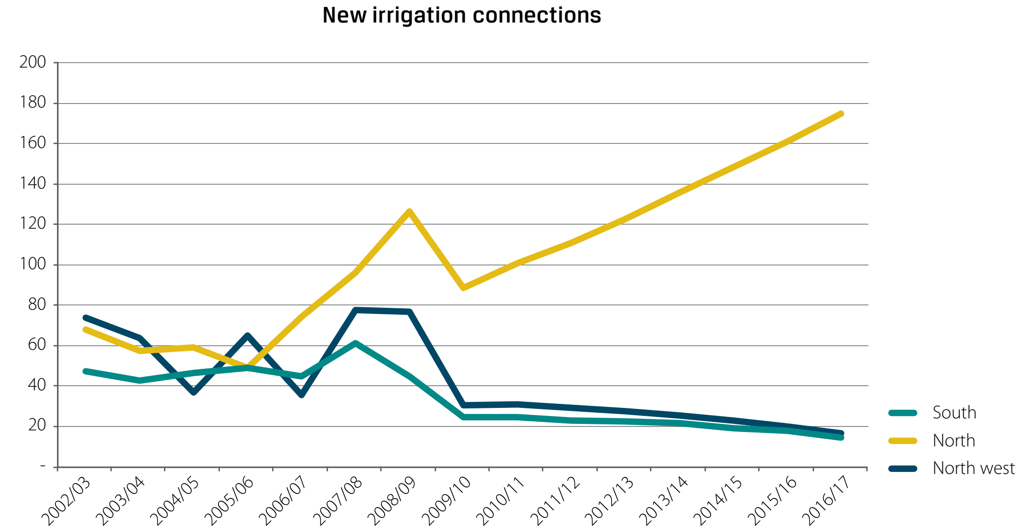


Irrigation customers

Figure 33 shows the irrigation customer forecast for the north west, north and south regions for the forthcoming *Regulatory Control Period*.

Figure 33

Forecast irrigation customer number

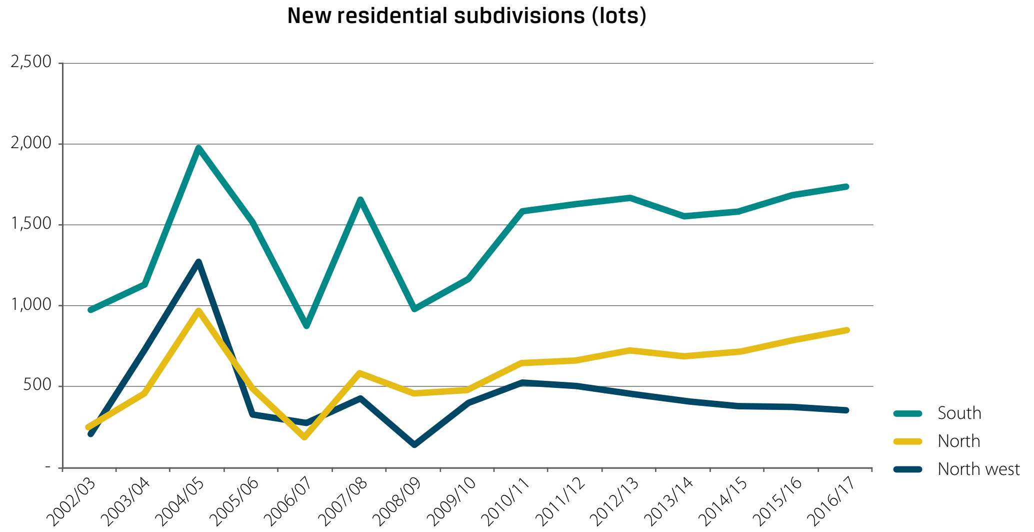


Residential subdivisions

Figure 34 shows the residential subdivision lots forecast for the north west, north and south regions for the forthcoming *Regulatory Control Period*.

Figure 34

Forecast residential subdivision lots



11. Capital expenditure

11. Capital expenditure

11.1. Rules requirements

Clause 6.12.3(a) of the *Rules* provides that the AER may accept or approve, or refuse to accept or approve, any element of Aurora's *Regulatory Proposal*. This means the AER may either accept or approve Aurora's total capital expenditure forecasts, or refuse to accept or approve Aurora's total capital expenditure forecasts on the basis of information provided in this *Regulatory Proposal*.

Clause 6.12.1(3) of the *Rules* provides that where the AER refuses to accept or approve Aurora's total capital expenditure forecasts it must set out its reasons for that decision, and its own estimate of the total of Aurora's required capital expenditure for the 2012-17 *Regulatory Control Period*. In reaching a decision the AER must be satisfied that the forecast reflects the capital expenditure criteria, and have regard to the capital expenditure factors.

Clause 6.5.7(a) of the *Rules* requires that Aurora's *Regulatory Proposal* must include the total forecast capital expenditure for the *2012-17 Regulatory Control Period*, which it considers meets each of the capital expenditure objectives. These objectives are to:

(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) maintain the quality, reliability and security of supply of *Standard Control Services*; and

(4) maintain the reliability, safety and security of the distribution system through the supply of *Standard Control Services*.

Clause 6.5.7(b) of the *Rules* requires that Aurora's capital expenditure forecast must:

(1) comply with the requirements of any relevant regulatory information instrument;

(2) be for expenditure that is properly allocated to *Standard Control Services* in accordance with the principles and policies set out in Aurora's Cost Allocation Method (CAM);

(3) include both:

(i) the total of the forecast capital expenditure for the relevant *Regulatory Control Period*; and

(ii) the forecast of the capital expenditure for each *Regulatory Year* of the relevant *Regulatory Control Period*; and

(4) identify any forecast capital expenditure that is for an option that has satisfied the regulatory test.

Clause 6.5.7(c) of the *Rules* requires that the AER accept Aurora's forecast of required capital expenditure if it is satisfied that the total of the forecast capital expenditure for the *2012-17 Regulatory Control Period* reasonably reflects the capital expenditure criteria. The capital expenditure criteria require that the forecast reflect:

(1) the efficient costs of achieving the capital expenditure objectives;

(2) the costs that a prudent operator in Aurora's circumstances 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.

Clause 6.5.7(e) of the *Rules* sets out 10 capital expenditure factors, which reflect the matters which the AER must have regard to in determining its satisfaction that the forecast capital expenditure for the *2012-17 Regulatory Control Period* reasonably reflects the capital expenditure criteria.

Further, schedule 6.1.1 of the *Rules* requires that Aurora set out 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 of the *Rules* and identifies the forecast capital expenditure by reference to well accepted categories such as:

(i) asset class (e.g. distribution lines, substations etc); or

(ii) category driver (e.g. 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 Aurora;

(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

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

In this chapter, Aurora will demonstrate its compliance with the capital expenditure criteria by demonstrating that the:

- identified scope is consistent with Aurora's regulatory obligations and with standard industry practice in meeting the capital expenditure objectives;
- demand and cost inputs have been either forecast or reviewed by independent expert third parties and determined to be realistic;
- scoping processes are reasonable and utilise realistic demand inputs, resulting in a prudent capital expenditure scope that has been reviewed and assessed by independent expert third parties where possible;
- costing processes are reasonable and incorporate realistic cost inputs, resulting in an efficient capital expenditure forecast; and
- identified scope can be delivered by Aurora.

Further, where expenditure differs significantly from that of the current *Regulatory Control Period*, such differences are explained.

11.2. 1 January 2004 – 31 December 2007

This section of Aurora's *Regulatory Proposal* will focus on the historic capital expenditure for the previous *Regulatory Control Period* (1 January 2004 – 31 December 2007).

Aurora has separated its capital expenditure into the categories that have been historically utilised by OTTER as part of its regulation of Aurora:

- non demand replacement;
- capacity – customer;
- capacity – system;
- system performance – reliability;
- system performance – power quality;
- connection assets;
- safety, health and environment;
- asset management capability;
- NEM and contestability related; and
- common service.

An analysis for each category is provided in the following sections.

The AER should note that during this *Regulatory Control Period* capital expenditure analysis commences on 1 July 2003 and concludes on 31 December 2007.

11.2.1. Non demand replacement

Non demand replacement expenditure refers to capital expenditure on infrastructure components whose condition has deteriorated and are posing a risk to Aurora not achieving its objectives through:

- increased safety and environmental risks;
- impacts on reliability and quality; or
- increased operational expenditure, normally as increased fault response, maintenance and repair costs.

Non demand expenditure therefore seeks to avoid corrective and forced maintenance expenditure associated with assets in poor condition or beyond their economic lives by providing for equipment to be replaced and refurbished in a structured and timely manner.

Background

Aurora considers that approximately 35 percent of non demand replacement is primarily driven by forced or required environmental, safety and compliance outcomes.

In addition to replacement of aged assets, examples of non demand replacement programs undertaken during the 2004-07 *Regulatory Control Period* include the replacement of:

- cast iron pothead cable terminations to address public safety concerns;
- low voltage live front switchboards to address operator safety concerns; and
- Siemens 8CK high voltage switchgear to address operator safety concerns.

Asset management outcomes

The primary asset management outcome achieved by this expenditure was the reduction in the risk the assets pose to Aurora. This risk reduction was achieved through the removal of assets in poor condition.

Results

Aurora's results for non demand replacement expenditure for the previous *Regulatory Control Period* are set out in Table 25.

Aurora has exceeded the OTTER proposed expenditure over this *Regulatory Control Period*, particularly in the 2004-05 and 2005-06 financial years. This expenditure variation was the result of an increase in expenditure to address the programs highlighted above.

Table 25

Non demand replacement capex

Aurora's non demand replacement capital expenditure					
$2009–10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	14.548	17.787	16.624	15.626	7.565
OTTER's proposed	13.248	13.649	13.317	13.526	6.834

11.2.2. Capacity – customer

Capacity – customer expenditure refers to capital expenditure required within the shared network and the relevant connection assets to service new or upgraded connections that have been requested by the customer.

Background

This expenditure is typically on works initiated by customers, as they seek new or augmented connections from Aurora.

The main categories of work associated with this expenditure are:

- residential connections;
- small commercial connections;
- large commercial connections;
- irrigation connections;
- residential subdivision developments; and
- commercial subdivision developments.

The key drivers of this expenditure are State and national economic factors, land/housing prices, subdivision land releases, planning schemes, Government policy and customer behaviour or lifestyle changes. These external factors limit Aurora's ability to influence the volumes and types of connections requested.

During the 2004-07 *Regulatory Control Period* there was a significant increase in the volumes of capacity – customer expenditure work required by Aurora. This increase continued throughout the *Regulatory Control Period*, culminating in expenditure peaking in 2007.

Asset management outcomes

There are no specific customer asset management outcomes arising from this work as it is undertaken for the connection of customers to the distribution network.

Increased expenditure in this area does however impact other capital and operating expenditure programs. These are dealt with in their respective expenditure categories.

Results

Aurora's results for capacity – customer expenditure for the previous *Regulatory Control Period* are set out in Table 26.

Aurora has significantly exceeded the OTTER proposed expenditure or each year of this *Regulatory Control Period*. This expenditure variation was the result of heightened economic activity in the State and a substantial increase in the level of customer connection activity.

Table 26

Capacity – customer capex

Aurora's capacity – customer capital expenditure					
$2009-10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	36.090	35.045	33.514	35.235	23.423
OTTER's proposed	17.233	14.811	14.644	14.550	7.302

11.2.3. Capacity – system

Capacity – system expenditure refers to capital expenditure associated with:

- major supply upgrades;
- augmentations of the high voltage system; and
- augmentations of the low voltage system including distribution substations.

Background

The expenditure during the 2004-07 *Regulatory Control Period* was associated with the following drivers:

- network and underlying customer security;
- managing loading risks on conductors, cables and transformation;
- management of system voltage profiles;
- meeting forecasted load;
- development on the distribution network, and
- enabling connection of distributed generation.

The outcomes arising from these drivers were:

- improved distribution network security delivering higher confidence in the electricity supply;
- reduction in risks to the customers, community, Aurora and its shareholders;
- improved power quality to Aurora's customers;
- improved capability to meet expected demands placed upon the distribution network;
- improved capability in the operation of the distribution network and as a consequence load management; and
- connection of distributed generators that mitigate some investments required for the distribution network.

Major supply work activities

Hobart area supply program (HASU)

Supply upgrades of zone substations and sub-transmission feeders were necessary due to increasing loading in the greater Hobart area and the western shore zone substations 22/11 kV configuration. The original sub-transmission voltage of 22 kV severely limited the power-transferring capabilities of western shore zone substations.

The work involved upgrades to the sub-transmission and zone substation network in conjunction with an increase in the voltage level to 33 kV.

The following zone substations were involved:

- East Hobart;
- Derwent Park;
- Claremont;
- Sandy Bay; and
- New Town.

Greater Launceston area upgrade (GLAD)

The Launceston network is significantly different in system architecture to that of the Hobart system. In Launceston and generally across the northern part of the State, Aurora derives its supply at feeder level (22 kV) from transmission-owned substations. Aurora does not have zone substations in Launceston or the northern area.

In conjunction with Transend, a work program was undertaken to implement supply upgrades within Launceston. The Aurora components of this program were HV feeder extensions, new feeder tails emanating from the transmission substations and general reconfigurations to manage load on the 22 kV distribution network, the transmission network and general security of the Launceston area. This program was undertaken over the 2004-07 *Regulatory Control Period*. It had commenced in the previous *Regulatory Control Period* and continued into the current *Regulatory Control Period*.

Augmentations – high voltage (HV)

Augmentations were undertaken to manage load growth and existing constraints within the distribution network.

The early 2000s were characterised by previous under-investment in the late 1980s which exacerbated a number of underlying load growth issues. The resultant activities specifically targeted heavily loaded HV feeders and areas where the system was inadequate to cater for the demand.

Work was also undertaken to reduce the overall exposure of Single Wire Earth Return (SWER) systems by the staged upgrading of these systems based upon a prioritised load assessment. This program was not designed to remove the SWER systems but to manage the impacts of loading upon the larger systems.

Augmentations HV – embedded generation

Augmentations were conducted to enable access to the HV network for a small number of private distributed generators. The management of the impacts upon the shared distribution network generally requires significant network studies and reinforcement. The customer however contributes to the cost of the augmentations.

Augmentations – low voltage (LV)

Augmentations were undertaken to manage localised limitations on the LV network including distribution substations (minor substations).

The work involved augmentation of lines and substations for loading purposes, targeting highly loaded equipment. An outcome of managing this work was the consequential reduction of supply quality complaints associated with heavily loaded infrastructure.

Asset management outcomes

The asset management outcomes that were achieved by this expenditure enabled a stronger, more resilient network to manage loading and voltage. Upgrading the relevant components when augmentation is undertaken provides an opportunity for the removal of redundant or superseded technology, e.g. line connectors, which ensures a more resilient network.

Components that are more likely to fail generally have a correlation to that of electrical stress (voltage and current). Upgrading the system components that are associated with these stresses produces a more reliable network, such that:

- connectors are less likely to fail – thereby increasing the security and reliability for Aurora's customers;
- clearance to ground for sagging conductors is reduced thereby providing a higher safety aspect to the community;
- transformers fail less often thereby reducing the incidents of environment damage; and
- customers see an improved quality of supply.

Results

Aurora's results for capacity – system expenditure for the previous *Regulatory Control Period* are set out in Table 27.

Aurora has significantly exceeded the OTTER proposed expenditure for the 2005-06 year of the *Regulatory Control Period*. This expenditure variation was the result of an acceleration of the work associated with the Hobart and Launceston supply upgrades and continued into the 2006-07 year.

Table 27

Capacity – system capex

Aurora's capacity – system capital expenditure					
$2009-10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	17.246	12.599	25.475	14.717	8.394
OTTER's proposed	15.763	15.599	8.746	8.826	3.237

11.2.4. System performance – reliability

System performance – reliability expenditure refers to capital expenditure targeted to improve system reliability. This is generally achieved through asset replacement, increased vegetation cutting, protection upgrades or feeder augmentations. The 2004-2007 *Regulatory Control Period* saw the first focused effort from Aurora to improve reliability.

Background

Although there had always been a requirement within the *TEC* for Aurora to meet a minimum level of reliability performance, the Regulator introduced a service incentive scheme as part of the 2003 Determination. This was the first such scheme in Tasmania and was specifically designed to improve the reliability of Aurora's distribution network.

The scheme had monetary rewards and penalties that would apply to Aurora based upon the achievement of annual frequency and duration targets during the *Regulatory Control Period* (similar to the Victoria 'S' factor scheme).

These incentives were a key consideration of reliability-targeted expenditure during the 2004-07 *Regulatory Control Period*.

Asset management outcomes

Aurora recognised that it had 19 feeders that contributed 50 percent of poor reliability performance and implemented a strategy aimed solely at improving the performance of these identified feeders.

The desire to improve reliability on these feeders resulted in a "Feeder Trunk Strategy". This strategy was to define the 'trunk' of the feeder, then aim to make this section of the feeder as reliable as possible. This was achieved by:

- auditing the 'trunk' section of line;
- replacing assets with a known contribution to poor performance;
- ensuring accurate discrimination of protection devices (including transmission); and
- ensuring the vegetation was managed for high reliability.

Results

Aurora's results for system performance – reliability expenditure for the previous *Regulatory Control Period* are set out in Table 28.

Aurora has no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 28

System performance – reliability capex

Aurora's system performance – reliability capital expenditure					
$2009-10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	3.429	7.202	9.670	6.723	4.392
OTTER's proposed	4.580	5.067	6.178	5.986	2.259

11.2.5. System performance – power quality

System performance – power quality expenditure refers to capital expenditure targeted to improve the quality of supply experienced by customers of the distribution network.

Background

Expenditure within this activity has been typically a reactive process whereby Aurora initiates remedial actions in response to customer power quality complaints. This expenditure is typically driven by incremental demand growth and cold weather.

The *TEC* defines the minimum level for technical parameters as well as the customer service obligations around response time following complaints.

Asset management outcomes

The capital funding allocated to power quality in this period was primarily directed towards the upgrade of low voltage circuits and distribution transformers in response to substandard voltage.

Results

Aurora's results for system performance – power quality expenditure for the previous *Regulatory Control Period* are set out in Table 29.

Aurora has no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 29

System performance – power quality capex

Aurora's system performance – power quality capital expenditure					
$2009-10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	3.484	3.359	3.769	3.182	1.637
OTTER's proposed	2.701	2.398	2.540	2.734	1.600

11.2.6. Connection assets

Connection asset expenditure refers to capital expenditure associated with the augmentation or replacement of assets used to connect installations to the distribution network, including service wires and service fuses. It does not include the provision of new service connections as these are captured within the capacity – customer expenditure category.

Background

Expenditure during the 2004-07 *Regulatory Control Period* was associated with the following drivers:

- safety;
- improved reliability of supply for customers; and
- non-demand replacement of aged and poor condition assets.

Asset management outcomes

During this period expenditure was characterised by:

- the replacement of failed service wires and service fuses; and
- the removal from service of approximately 23,000 Sicame service fuses that had been identified as having a high probability of failure and an associated risk of fire-start as a consequence of the failure mode of the fuse. Removal of these fuses reduced the safety and fire risk associated with the asset.

Results

Aurora's results for connection asset expenditure for the previous *Regulatory Control Period* are set out in Table 30.

Aurora has significantly exceeded the OTTER proposed expenditure for the 2004-05 and 2005-06 years of this *Regulatory Control Period*. This expenditure variation was the result of the removal of the failure prone Sicame fuses. Expenditure returned to levels closer to those proposed by OTTER during 2007-08.

Table 30

Connection assets capex

Aurora's connection assets capital expenditure					
$2009–10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	4.014	8.252	8.679	5.033	2.307
OTTER's proposed	2.114	2.120	2.104	2.099	1.058

11.2.7. Safety, health and environment

Safety, health and environment capital expenditure refers to capital expenditure targeted at addressing issues of a safety, health or environmental nature. During the 2004-07 *Regulatory Control Period* this expenditure included two main programs:

- bushfire mitigation; and
- undergrounding in special areas.

Background

The bushfire mitigation program aims to reduce the risk of fire-start by distribution assets in high fire danger areas. Prior to the commencement of the 'fire season' routine asset inspections and special fire audits are used to identify and address assets and construction arrangements deemed to be at risk of initiating a fire in high fire danger areas.

The undergrounding in special areas program replaces overhead distribution assets with underground reticulation in areas of significant heritage, scenic, environmental or tourist appeal. This program is undertaken in conjunction with the State and local governments.

Asset management outcomes

Specific programs were implemented at identified areas to address identified fire mitigation issues and a number of undergrounding projects were undertaken during the *Regulatory Control Period*.

Results

Aurora's results for safety, health and environment expenditure for the previous *Regulatory Control Period* are set out in Table 31.

Aurora has significantly underspent the OTTER proposed expenditure for the 2004-05 to 2006-07 years of this *Regulatory Control Period*. This expenditure variation was the result of lower than anticipated instances requiring system augmentations to address fire risk issues.

Table 31

Safety, health and environment capex

Aurora's safety, health and environment capital expenditure					
$2009–10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	1.233	0.835	0.399	0.441	0.481
OTTER's proposed	1.636	1.597	1.627	1.444	0.458

11.2.8. Asset management capability

Asset management capability expenditure refers to capital expenditure on information technology and operational technology programs that are required to manage the electricity distribution business and involves two key elements:

- making decisions on the assets, such as:
  - what assets to build;
  - how to build them; and
  - how to maintain and operate them;
  - to achieve the best balance of desired outcomes; and
- executing those decisions effectively and efficiently.

Background

In order to provide a consistent and continuing focus on developing its asset management capability Aurora developed a five-step asset management process model predicated upon:

- knowing the assets (including information feedback);
- analysis and decision-making;
- prioritising the activity and producing the program of work;
- managing the delivery of the program; and
- delivering the program.

To deliver a better balance of long-term outcomes Aurora developed, and has executed, a long-term strategy to reshape its asset management capability. The key elements of that strategy are:

- highly analytical and targeted asset decision-making;
- decision-making to be made at multiple levels to achieve a good balance of customer outcomes;
- clear and transparent decision-making and prioritisation; and
- highly efficient and effective ways of delivering the three major streams of work:
  - reactive;
  - maintenance; and
  - construction.

Asset management outcomes

Over the 2004-07 *Regulatory Control Period* Aurora invested in an improved information technology environment in line with this strategy. Specific projects implemented include:

Field tools

- continued development of the distribution asset information system (DAIS) pole and line inspection system; and
- implementation of a geospatial field audit tool to support audit/design processes.

Simplify IT environment

- upgrade of core asset management systems from the combination of Intergraph Corporation Pty Ltd (Intergraph) facilities rulebase application model management environment (FRAMME) and EMS Solutions Pty Ltd (EMS) works assets scheduling and programming (WASP) asset management systems to a single geospatial asset management system based on Intergraph's G-Technology;
- implementation of Intergraph's InService Outage Management System to improve fault management decision-making and customer service;
- implementation of Telephony Video Data Ltd. (TVD) Service Order System to facilitate improved customer service order management; and
- introduction of a data warehouse to allow combination of data from sources such as FRAMME geospatial world, Department of Primary Industries, Park, Water and Environment (DPIPWE) land parcel data, WASP asset data, the reliability reporting system and WASP works management.

Process tools

- introduction of Integraph's WebMap as a platform across the business for providing geospatial and tabular information on many aspects of the business;
- introduction of a number of process tools to facilitate business processes such as guaranteed service level (GSL) payment and private pole management; and
- introduction of a fault locator tool which combines fault information from Nulec reclosers with the distribution network information system (DINIS) load flow tool to produce recommended sites for field investigation.

Data acquisition

- completion of the asset to customer link at transformer level, which enables Aurora to locate its customers spatially and understand how they are connected to the distribution network.

Other

- Introduction of remote control capability to all Nulec reclosers; and
- use of Geomedia geospatial information system (GIS) as a planning tool.

Results

Aurora's results for asset management capability expenditure for the previous *Regulatory Control Period* are set out in Table 32.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 32

Asset management capability capex

Aurora's asset management capability capital expenditure					
$2009-10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	1.969	1.725	1.945	3.313	1.550
OTTER's proposed	2.793	3.106	2.734	2.791	1.458

11.2.9. NEM and contestability related

NEM and contestability related expenditure refers to capital expenditure relating to Aurora's entry into the National Electricity Market and the establishment of retail contestability within the State. It comprises two key categories of expenditure:

- the establishment of IT systems (including allocations from the corporate divisions of Aurora); and
- the additional resources required by Aurora to establish and operate market systems.

Results

Aurora's results for NEM and contestability related expenditure for the previous *Regulatory Control Period* are set out in Table 33.

Aurora has significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Whilst Aurora's expenditure pattern may be inconsistent with OTTER's proposed expenditure, the uncertain nature of the expenditure was recognised by OTTER and an adjustment mechanism was included within Aurora's 2003 Determination to account for these variations.

Table 33

NEM and contestability related capex

Aurora's NEM and contestability related capital expenditure					
$2009-10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	0.094	0.097	3.192	0.698	2.791
OTTER's proposed	0.125	1.378	4.396	3.757	1.878

11.2.10. Common service

Common service expenditure refers to capital expenditure relating to assets that are not an integral part of the distribution network or 'non-network assets'. It comprises three key categories of expenditure:

- IT and minor assets (mainly comprising allocations from the corporate divisions of Aurora);
- facilities (land and buildings); and
- fleet (vehicles, plant and equipment).

Results

Aurora's results for common service expenditure for the previous *Regulatory Control Period* are set out in Table 34.

Aurora has exceeded the OTTER proposed expenditure for the 2004-05, 2005-06 2006-07 years of the *Regulatory Control Period*. This expenditure variation was the result of the establishment of Aurora's southern operations centre at Cambridge and the establishment of a number of corporate systems required for NEM operations.

Table 34

Common service capex

Aurora's common service capital expenditure					
$2009-10	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	1/7/07-31/12/07 ($m)
Actual	12.190	22.261	24.426	24.054	5.759
OTTER's proposed	6.675	6.732	6.231	6.035	2.931

11.3. 1 January 2008 – 30 June 2012

This section of Aurora's *Regulatory Proposal* will focus on the actual and forecast capital expenditure for the current *Regulatory Control Period* (1 January 2008 – 30 June 2012).

Aurora has separated its capital expenditure into the categories that have been historically utilised by OTTER as part of the current economic regulation of Aurora:

- non demand replacement;
- capacity – customer;
- capacity – system;
- system performance – reliability;
- system performance – power quality;
- connection assets;
- safety, health and environment;
- asset management capability;
- NEM and contestability related; and
- common service.

An analysis for each category is provided in the following sections.

The AER should note that this *Regulatory Control Period* is characterised by a change from calendar year to financial year. This change was effected by means of a six month only period at the commencement of the *Regulatory Control Period*.

11.3.1. Non demand replacement

Non demand replacement expenditure refers to capital expenditure on infrastructure components whose condition has deteriorated and are posing a risk to Aurora achieving its objectives through:

- increased safety and environmental risks;
- impacting on reliability and quality; or
- increased operational expenditure, normally as increased fault response, maintenance and repair costs.

Non demand replacement therefore seeks to avoid corrective and forced maintenance expenditure associated with assets in poor condition or beyond their economic lives by providing for equipment to be replaced and refurbished in a structured manner.

Background

Examples of non demand replacement programs undertaken during the 2008-12 *Regulatory Control Period* include:

- the continued replacement of cast iron pothead cable terminations to address public safety concerns;
- the continued replacement of low voltage live front switchboards to address operator safety concerns;
- the continued replacement of Siemens 8CK high voltage switchgear to address operator safety concerns;
- replacement of LV circuit breakers known to contain asbestos arc chutes to address operator safety concerns; and

- replacement of Low Voltage (LV) concentric sheath aluminium conductor (CONSAC) cable to mitigate against the risk of electric shock to customers.

Asset management outcomes

The asset management outcomes that were achieved by this expenditure were the reduction of risks posed by the assets through the removal of poor condition assets.

This included the:

- removal of the remaining Siemens switchgear units;
- replacement of the poorest condition sections of CONSAC cable; and
- continuation of the galvanised iron (GI) and copper conductor, cast iron pothead, live front board and asbestos arc chute replacement programs.

Results

Aurora's results/forecasts for non demand replacement expenditure for the current *Regulatory Control Period* are set out in Table 35 below.

With the exception of the six month period ended 30 June 2008, Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. This expenditure variation was the result of a reduction in Aurora's pole condemning rates and the subsequent reduction in the need for Aurora to replace condemned poles.

Table 35

Non demand replacement capex

Aurora's non demand replacement capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	7.565	22.266	32.176	31.144	30.135
OTTER's proposed	11.099	24.195	30.470	32.362	32.082

11.3.2. Capacity – customer

Capacity – customer expenditure refers to capital expenditure required within the shared network and the relevant connections assets to service new or upgraded connections that have been requested by the customer.

Background

This expenditure is typically initiated by customers as they seek new or augmented connections from Aurora.

The level of capacity – customer expenditure continued at levels similar to those experienced during the previous *Regulatory Control Period*. Higher interest rates and a slowing of Tasmanian economic conditions has seen this expenditure peak and it is now anticipated that future levels will be lower than those previously experienced.

Asset management outcomes

There are no specific customer asset management outcomes arising from this work as it is undertaken purely to provide for the connection of customers to the distribution network.

Increased expenditure in this area does however impact other capital and operating expenditure programs and these outcomes are explored within those expenditure categories.

Results

Aurora's results/forecasts for capacity – customer expenditure for the current *Regulatory Control Period* are set out in Table 36.

Aurora has exceeded the OTTER proposed expenditure for each year of this *Regulatory Control Period*. This expenditure variation was the result of continued heightened economic activity in the State and a continued increase in the level of customer connection activity.

Table 36

Capacity – customer capex

Aurora's capacity – customer capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	23.423	47.864	44.778	42.336	43.079
OTTER's proposed	16.356	32.712	32.712	32.712	32.712

11.3.3. Capacity – system

Capacity – system expenditure refers to capital expenditure associated with:

- major supply upgrades;
- augmentations of the high voltage system;
- augmentations of the low voltage system including distribution substations; and
- demand side management.

Background

The expenditure during the 2008-12 *Regulatory Control Period* was associated with the following drivers:

- network and underlying customer security;
- managing loading risks on conductors, cables and transformation;
- management of system voltage profiles;
- meeting forecasted load;
- development on the network, and
- enabling connection of embedded generation.

The outcomes arising from these drivers were:

- improved network security, delivering higher confidence in the electricity supply;
- reduction in risks to the customers, community, Aurora and its shareholders;

- improved power quality to Aurora's customers;
- improved capability to meet expected demands placed upon the distribution network;
- improved capability in the operation of the distribution network and as a consequence load management; and
- connection of embedded generators, which mitigates some investments required for the distribution network.

Major supply work activities

Cambridge and Trial Harbour zone substations

The construction of zone substations occurred at Cambridge, near the Hobart airport, and at Trial Harbour on the West Coast to meet projected major customer demands.

Transend substation refurbishments

Work was undertaken in conjunction with Transend's ongoing refurbishment program, making additional 11 and 22 kV feeder tails available. The substations concerned had major upgrades undertaken and required the existing connections to be remade and extended. The substations concerned were:

- Hadspen;
- Devonport; and
- Electrona.

Hobart area supply upgrade

There was some minor works undertaken to complete the Hobart Area Supply Upgrade.

Greater Launceston area upgrade (GLAD)

Significant feeder work was and is still being undertaken to manage the Launceston area ahead of the commissioning of a St Leonards substation by Transend. This substation is expected to be commissioned in 2012.

Hobart eastern shore upgrade (HES)

Hobart's eastern shore has had consistent load growth since 2000. The continual load increase has placed pressure upon the transmission assets as well as the Aurora zone substation assets and their ability to meet projected demand.

The construction of a new zone substation at Howrah has recently commenced, with the construction of an additional zone substation at Rosny planned for 2012-13.

Kingston area upgrade

Further major reinforcement is being considered for the Kingston area (southern suburb of Hobart) with the installation of a new 33/11 kV Kingston zone substation. Kingston zone substation is premised upon a strong annual load growth with the load forecast showing inability to supply following winter 2012.

Augmentations – high voltage (HV)

Work was and is being undertaken to mitigate high loading of the HV network and consequently power quality issues. This work program covers a number of specific areas on the HV system that have different drivers.

Single wire earth return (SWER) systems.

Work is being undertaken in the Blessington, Reedy Marsh, Mathinna, Green Valley, Slopen Main and Waterhouse areas to manage the loading on the SWER system.

Aurora SWER systems are managed on the basis that the load on each SWER system is no more than 100 kVA. As this is exceeded staged augmentations are undertaken to upgrade to single or multi-phase distribution that will bring the load below the 100 kVA level.

Voltage conversions

The areas of Westerway, Hamilton, Gretna and Richmond Valley have 11 kV distribution. This voltage is more suited to an urban topography and not that of areas with high levels of irrigation pump penetration.

Work is being done to deliver a rural style voltage in these areas. For Hamilton, Gretna and Westerway the conversions to 22 kV will remove the need to augment the respective zone substations, which are in poor electrical health.

Augmentation for load

This work is undertaken to reduce load on the specific feeders to manage the planning rating of the conductors and cables.

Augmentations for development including security

This work is to assist with the development of the system taking into account the load forecast for the given areas. This work is targeted at the development of a system that can be dynamically managed from the frontline Operations perspective. Such work entails feeder interconnections, new feeder outlet and reconfiguration of the infrastructure to minimise the limitations of the network architecture.

Demand side management (DSM)

To improve Aurora's capability to enable an effective DSM strategy and initiatives a report was compiled to:

- assess compliance with the national framework for distribution network planning;
- develop a business structure to support compliance and program initiatives; and
- review the 40 year development strategy and plans to identify possible DSM opportunities[1].

This report has enabled a number of significant business outcomes for the existing and proposed distribution network for the present and subsequent *Regulatory Control Periods*.

Augmentations – low voltage (LV)

Augmentations were undertaken to manage localised limitations on the LV network including distribution substations (minor substations).

The work entails augmentation of lines and substations for loading purposes, targeting highly loaded equipment. An outcome of managing this work is the consequential reduction of supply quality complaints associated with heavily loaded infrastructure.

1 Aurora Energy Pty Ltd, *Distribution System Planning Report 2010*, pages 9 and 92.

Asset management outcomes

The asset management outcomes that were achieved by this expenditure enabled a stronger, more resilient network to manage loading, voltage and other attributes.

Results

Aurora's results/forecasts for capacity – system expenditure for the current *Regulatory Control Period* are set out in Table 37.

Aurora has departed from OTTER's proposed expenditure due to the deferment of parts of the eastern shore upgrade planned for the 2008-09 year until the later parts of this *Regulatory Control Period*.

Table 37

Capacity – system capex

Aurora's capacity – system capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	8.394	15.814	22.263	25.420	28.139
OTTER's proposed	9.404	34.107	23.281	15.356	12.505

11.3.4. System performance – reliability

System performance – reliability expenditure refers to capital expenditure targeted to achieve system reliability compliance. This is generally achieved through asset replacement, increased vegetation cutting, protection upgrades or feeder augmentations.

Background

The previous *Regulatory Control Period* focused on average system performance. During the period Aurora and the Regulator recognised the shortcomings of this approach and its effect on customers. A joint working group comprising OTTER, the Office of Energy Planning and Conservation (OEPC) and Aurora developed a new set of standards that were targeted toward community outcomes.

Aurora's response to complying with these standards is the targeted reliability improvement program (TRIP). This program targets individual communities with non-compliant performance and achieves performance compliance through capital upgrades. The upgrades consist of one or more of the following activities:

- asset replacement;
- protection upgrade;
- vegetation management;
- distribution automation; or
- feeder augmentation.

Asset management outcomes

To comply with these new standards by 2012, Aurora has initiated programs aimed at improving the outcomes for all communities. Aurora anticipates that it will have undertaken 44 individual community improvement projects by the end of this *Regulatory Control Period*.

Results

Aurora's results/forecasts for system performance – reliability expenditure for the current *Regulatory Control Period* are set out in Table 38.

Aurora has exceeded the OTTER proposed expenditure for the 2008-09, 2009-10 and 2010-11 years of this *Regulatory Control Period*. This expenditure variation was the result of the acceleration of targeted reliability improvement programs. Future expenditure is anticipated to reduce to levels lower than those proposed by OTTER as Aurora moves to a compliance regime for reliability.

Table 38

System performance – reliability capex

Aurora's system performance – reliability capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	4.392	10.591	12.205	9.927	6.183
OTTER's proposed	4.341	8.857	10.378	8.431	8.499

11.3.5. System performance – power quality

System performance – power quality expenditure refers to capital expenditure targeted to improve the quality of supply experienced by customers of the distribution network.

Background

The drivers for power quality expenditure continue from the previous *Regulatory Control Period*. Increasing load demand continued to result in customer complaints during winter and corresponding capital upgrades.

Cable PI was introduced in 2009 and provided an opportunity to monitor steady state voltage at customer premises. As expected, customer complaints regarding steady state voltage peaked in early 2010 and resulted in a corresponding transient increase in network augmentation in response. Aurora considers that this exercise allowed Aurora to address many of the very worst of voltage issues in the distribution network.

Asset management outcomes

Outcomes remain consistent with those of the previous *Regulatory Control Period*, albeit with an increase in expenditure due to the CablePI initiative.

Aurora also increased the level of distribution network power quality monitoring. All feeder connections will have basic power quality monitoring and ground mounted substations now come standard with power quality monitoring.

Results

Aurora's results/forecasts for system performance – power quality expenditure for the current *Regulatory Control Period* are set out in Table 39.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 39

System performance – power quality capex

Aurora's system performance – power quality capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	1.637	4.631	5.327	5.118	3.629
OTTER's proposed	2.442	4.816	4.822	4.831	4.840

11.3.6. Connection Assets

Connection assets expenditure refers to capital expenditure associated with the augmentation or replacement of assets used to connect installations to the distribution network including service wires and service fuses. It does not include the provision of new service connections as these are captured within the capacity – customer expenditure category.

Background

Expenditure during the 2008-12 *Regulatory Control Period* was associated with the following drivers:

- safety;
- improved reliability of supply for customers;
- non-demand replacement of aged and poor condition assets;
- removal of meter panels containing asbestos; and
- removal of assets that are non-compliant with the requirements of the *Rules* and the National Metrology Procedure.

Asset management outcomes

During this period expenditure was characterised by:

- the replacement of failed service wires and service fuses under fault conditions;
- the removal from service of a further 3,500 Sicame service fuses;
- a service wire replacement program for services identified as poor condition during an asset inspection program; and
- replacement of overloaded, obsolete and poor condition metering transformers identified by inspections, testing and audits as required under the *Rules* and National Metrology Procedure[2].

Results

Aurora's results/forecasts for connection assets expenditure for the current *Regulatory Control Period* are set out in Table 40.

With the exception of the 2010-11 and 2011-12 years, Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. An analysis of failure data has enabled Aurora to revise its asset replacement strategy and expenditure is forecast to remain consistent with current levels.

Table 40

Connection assets capex

Aurora's connection assets capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	2.307	4.802	6.146	7.007	6.007
OTTER's proposed	2.072	5.355	6.484	8.482	10.610

11.3.7. Safety, health and environment

Safety, health and environment expenditure refers to capital expenditure targeted at addressing issues of a safety, health or environmental nature. During the 2008-12 *Regulatory Control Period* this expenditure includes three main programs:

- bushfire mitigation;
- undergrounding of special areas; and
- threatened species impact mitigation.

In 2008-09 Aurora also introduced the CablePI device to mitigate the safety risk associated with broken neutrals.

Background

The bushfire mitigation program aims to reduce the risk of fire-start by distribution assets in high fire danger areas.

The undergrounding of special areas program aims to replace overhead distribution assets with underground reticulation in areas of significant heritage, scenic or environmental significance or tourist appeal.

The threatened species impact mitigation program aims to limit the risk posed by Aurora's assets to threatened species, to the lowest level that is reasonably practicable. This program was introduced in this *Regulatory Control Period* as a result of an increase in the number of incidents of endangered wildlife interacting with electrical infrastructure in the previous period (particularly raptors).

A Public Authority Management Agreement (PAMA) between Aurora and the Department of Primary Industries, Parks, Water and Environment (DPIPWE) was signed in 2008 to address the threat of electrocution from the collision of threatened bird species with Aurora's distribution infrastructure.

2 AEMO, *NEM Metrology Procedure.*

Asset management outcomes

Specific programs were implemented at identified areas to address fire mitigation issues and undergrounding projects were again undertaken.

The activities undertaken as part of the PAMA have resulted in a reduction in the number of deaths as a result of interactions with steel poles, however there are still a number of deaths associated with mid-span collisions.

Results

Aurora's results/forecasts for safety, health and environment expenditure for the current *Regulatory Control Period* are set out in Table 41.

With the exception of the 2008-09 year, Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. This expenditure variation was the result of the introduction of the Cable PI device.

Table 41

Safety, health and environment capex

Aurora's safety, health and environment capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	0.481	8.769	2.404	2.433	1.485
OTTER's proposed	0.680	1.366	1.374	1.382	1.389

11.3.8. Asset management capability

Asset management capability expenditure refers to capital expenditure on information technology and operational technology programs that are required to manage the electricity distribution business.

Background

Aurora's information technology strategy aims to:

- utilise field tools to collect good asset data necessary for intelligent, risk-based decision-making;
- simplify the IT environment through the use of:
  - core systems to support base level business processes;
  - 3G communications to provide seamless field communications; and
  - data warehouse strategies to combine core system data to support decision-making process tools.
- utilise web based decision-making tools using data from the data warehouse; and
- implement targeted asset data acquisition programs to fill critical "data holes" in the business.

Asset management outcomes

Aurora continued to develop its GIS and decision support capability and was able to leverage off the base infrastructure of G-Technology and the spatial data warehouse to build tailored solutions at relatively low-cost. Aurora invested in the following during this regulatory period:

Core systems

Aurora continued with upgrades to three of its core systems over this period, namely:

- G-Technology – expenditure has continued to develop the network model and connectivity;
- InService[3] – expenditure focused on enabling as yet unused capability within InService, implementing the trouble analysis capability and limited deployment of InService Mobile to field crews enabling direct dispatch of reactive work; and
- WASP[4] – Aurora is currently increasing the planning capability of WASP utilising WASP Basix[5] to allow more efficient planning of work programs.

Data warehouse

Aurora continued to develop its data warehouse as an integral part of its information systems strategy in order to support the continued development of process tools.

Process and decision support tools

Aurora continued to develop the process tool and decision environment to support many processes in the business.

Data acquisition

Aurora continued to improve its knowledge of its assets through a combination of targeted audits or data migration from legacy systems.

Results

Aurora's results/forecasts for asset management capability expenditure for the current *Regulatory Control Period* are set out in Table 42.

With the exception of the 2008-09 and 2010-11 years, Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Aurora departed from the OTTER proposed expenditure in these years as a result of undertaking a strategic improvement program focusing on improving processes and systems within the distribution business; primarily in the works management, works planning and system operations functions.

3 Intergraph's Outage Management System.
4 Work Allocation and Scheduling Program, which provides asset management and associated works management functions.
5 A platform within WASP which allows that program to be tailored to particular purposes within a business. .

Table 42

Asset management capability capex

Aurora's asset management capability capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	1.550	4.378	2.657	4.142	3.315
OTTER's proposed	1.254	1.667	2.081	1.830	3.083

11.3.9. NEM and contestability related

NEM and contestability related expenditure refers to capital expenditure relating to Aurora's continued participation in the National Electricity Market and the establishment of further tranches of retail contestability within the State. It comprises two key categories of expenditure:

- the establishment of IT systems (including allocations from the corporate divisions of Aurora); and
- the additional resources required by Aurora to establish and operate market systems.

Results

Aurora's results for NEM and contestability related expenditure for the current *Regulatory Control Period* are set out in Table 43.

Aurora had significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Whilst Aurora's expenditure pattern may be inconsistent with OTTER's proposed expenditure, the uncertain nature of the expenditure was recognised by OTTER and an adjustment mechanism was included within Aurora's 2007 Determination to account for these variations. The variation in 2010-11 relates specifically to the Tasmanian Governments decision to open a further tranche of contestability The significant variation in 2010-11 relates specifically to the Tasmanian Government decision to open a further tranche of contestability.

Table 43

NEM and contestability based capex

Aurora's NEM and contestability based capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	2.791	2.343	3.406	12.360	0.000
OTTER's proposed	0.820	1.000	1.271	0.951	1.206

11.3.10. Common service

Common service expenditure refers to capital expenditure relating to assets that are not an integral part of the distribution network or 'non-network assets'. It comprises three key categories of expenditure:

- IT and minor assets (mainly comprising allocations from the corporate divisions of Aurora);
- facilities (land and buildings); and
- fleet (vehicles, plant and equipment).

Results

Aurora's results/forecasts for common service expenditure for the current *Regulatory Control Period* are set out in Table 44.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Whilst the 2010-11 year may appear to show significant departure from the expenditure proposed by OTTER, the OTTER allowance for the relocation of the Network division to Kirksway Place was a net allowance including sale proceeds for Aurora's Moonah site. These sale proceeds have yet to eventuate and the forecast expenditure for 2010-11 is the gross capital expenditure for that year.

Table 44

Common service capex

Aurora's common service capital expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual/ forecast	5.759	17.651	17.240	22.218	17.480
OTTER's proposed	8.233	17.355	16.192	18.263	15.605

11.4. 1 July 2012 – 30 June 2017

This section of Aurora's *Regulatory Proposal* will focus on the forecast capital expenditure for the forthcoming *Regulatory Control Period* (1 July 2012 – 30 June 2017).

Aurora has developed a detailed work program containing the capital projects it has forecast will be required during the 2012-17 *Regulatory Control Period*. This work program includes estimated volumes and rates for each project, for each year of the *Regulatory Control Period*. These projects have been further classified to individual work and RIN categories and form the basis of Aurora's total capital expenditure forecasts for the 2012-17 *Regulatory Control Period*. Aurora's work program is appended as an attachment to this *Regulatory Proposal*.

Aurora has separated its capital expenditure proposals into three primary RIN categories and six sub-categories as detailed in Table 45.

Table 45

Capex RIN categories

RIN category	RIN sub-category
Capitalised overheads	Capitalised overheads
System	Demand related
	Non-demand related
	Regulatory obligations or requirements
Non-system	Non-network
	SCADA and network control

Methodology to derive forecasts

The methodology for deriving the forecasts is the process that Aurora's engineers and management followed, and the policies and procedures that they had regard to, in developing the work programs. These methodologies and discussions relating to the forecasts are set out in the following sections by subcategory.

The methodology used by Aurora to develop the forecast projects for each work category is set out in Aurora's management plans. Within each subcategory Aurora also provides a list of the relevant work categories (where expenditure over the Regulatory Control Period exceeds $0.5 million), grouped by the associated management plans.

A forecast for each RIN sub-category is provided in the following sections.

11.4.1. Capitalised overheads

Background

Capitalised overheads relate to the capitalised portion of Network Services direct overheads that are allocated to each of the AER's RIN categories and subcategories. These Network Services direct overheads comprise overhead costs from three shared cost pools, being:

- corporate and shared costs;
- distribution shared services; and
- Network Services management overheads.

Under the normal operation of Aurora's models, the values for each capital expenditure work category of Aurora's work program would be inclusive of the capitalised portion of direct overhead. However, consistent with the AER's RIN requirements Aurora has created a separate expenditure category in its models so that it can quantify the magnitude of this capitalised component throughout the forthcoming regulatory control period.

Drivers

The drivers for this category are diverse as they relate to the drivers for each of the three shared cost pools comprising Network Services overheads.

Methodology to derive forecasts

The methodology for deriving capitalised overheads expenditure forecasts varies on the basis of the nature of the shared cost, as the following demonstrates:

- for corporate and shared costs, the volumes and projects for the activities that underpin this expenditure are forecast by Aurora's corporate team. These forecasts are built up with regard to both corporate wide strategies and parameters; and forecasts and planning considerations by each division and subsidiary within Aurora. The costs are allocated to each division and subsidiary using Aurora's ICAM on the basis of the most appropriate driver;
- for distribution shared costs, the volumes and projects for the activities that underpin this expenditure are forecast by Aurora's distribution business. These forecasts are built up with regard to forecasts and planning considerations of both its Network Services and Network divisions; and
- for Network Services management costs, the volumes and projects for the activities that underpin this expenditure are forecast by Aurora's Network Services division. These forecasts are built up with regard to forecasts and planning considerations of both Network Services and Network divisions.

A total of $98.5 million ($2009-10 excluding escalations) is forecast to be required within this category over the *Regulatory Control Period*. This expenditure is forecast to be required for the capitalised overhead component of each RIN subcategory. The profile of forecast expenditure varies moderately throughout the *Regulatory Control Period*.

Aurora uses its capital expenditure component of its work program, as well as the Network Services component of its unit rates model, to derive capitalised overheads. The methodology for deriving the work program is set out in Aurora's management plans and network strategy documents.

Capitalised overheads are derived by allocating Network Services overheads to each capital expenditure RIN subcategory on the basis of direct labour hours. These overheads are split off from the values in the work program and aggregated on an annual basis to establish the forecasts for the forthcoming *regulatory control period*.

Key assumptions

The key assumptions underlying Aurora's capitalised overheads forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's forecasts for Network Services overheads will remain unchanged over the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- the *TEC* will remain in force, and that any replacement will impose similar and not more prescriptive requirements upon Aurora in relation to Aurora's work program;
- Aurora's method of assessing forecasts for capital expenditure is a prudent method of determining the works required;
- the overheads applied to expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to expenditure will be the same as the out-turn costs faced by Aurora.

Opex/capex interactions

There is no specific interaction between capitalised overheads and operating expenditure.

Expenditure variations

There are no instances where expenditure differs significantly from that of the current *Regulatory Control Period*. The nature of this expenditure (capitalised overheads) is however driven by the volume of projects that are undertaken by Aurora and will vary year by year.

Forecasts

Aurora's forecasts (including escalations) for capitalised overheads expenditure for the forthcoming *Regulatory Control Period* are set out in Table 46 below.

Table 46

Capitalised overheads capex

Aurora's capitalised overheads expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	20.506	20.606	19.850	19.383	19.565

11.4.2. Demand related

Background

Demand related expenditure refers to the capital expenditure required to augment Aurora's distribution network.

This capital expenditure is driven by growth in peak demand across Aurora's network. To ensure ongoing supply to customers, Aurora must augment its network assets to accommodate this additional demand, as peak demand approaches the network capacity limits. Demand related capital expenditure is impacted by two key needs, being:

- the additional capacity requirements of customer initiated works; and
- other reinforcements required to meet growth in demand from existing customers in constrained areas of the network.

Demand related capital expenditure includes projects undertaken in the following categories:

- customer initiated; and
- reinforcements.

Drivers

The drivers for demand related expenditure are:

- customer service;
- legislation;
- safety; and
- capacity.

Methodology to derive forecasts

As noted previously, the volumes and projects for all work categories that underpin this expenditure are set out in Aurora's work program. The individual categories within the work program can be referenced to specific sections of Aurora's 2011 management plans, and this section sets out the relevant management plan for each work category listed.

Customer initiated

This category is initiated and undertaken at the request of the customer and includes the connection of a new or an altered customer connection either directly connected to the network or via dedicated connection assets. The *Rules* and the *TEC* articulate the minimum specific technical requirements to be provided when assessing, considering and/or establishing a customer connection.

A total of $181.3 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category over the *Regulatory Control Period*. This expenditure is forecast to be required for 195 line items of varying types across five overall subcategories, being:

- customer initiated connection assets;
- customer initiated non-major works;
- customer initiated subdivisions;
- customer initiated substations; and
- customer initiated major works.

Customer initiated connection assets

There are 50 line items across the *Regulatory Control Period* with a total value of $11.5 million. The largest work category relates to install service connections (new installations) with an associated expenditure of $6.4 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan – 2011 Connection Assets:

- CT and VT – new;
- install service connections (new installations); and
- meter panels.

The anticipated works are based on trend analysis and econometric forecast drivers.

Customer initiated non-major works

There are 95 line items across the *Regulatory Control Period* with a total value of $107.3 million. The largest work category relates to Supply High Voltage General Supply Installations Underground, with an associated expenditure of $32.2 million across the period.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Customer Initiated Capital Works:

- preliminary drive by design (retail);
- supply high voltage general supply installation overhead;
- supply high voltage general supply installation underground;
- supply high voltage irrigation overhead;
- supply high voltage permanent occupied residence overhead;
- supply low voltage external and crossover poles etc overhead; and
- supply permanent occupied residence underground.

The anticipated works are based on trend analysis by Aurora and econometric forecasted drivers.

Customer initiated subdivisions

There are 20 line items across the *Regulatory Control Period* with a total value of $44.9 million. The largest work category relates to the supply subdivision in underground lots with a total value of $39.9 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan – 2011 Customer Initiated Capital Works:

- supply subdivision 5 lot min overhead; and
- supply subdivision n lots underground.

The anticipated works are based on trend analysis and econometric forecasted drivers.

Customer initiated substations

There are 10 line items across the *Regulatory Control Period* with a total value of $1.3 million. This subcategory comprises a single work category; supply build or alter distribution substations, with an average annual value of $0.3 million. This profile of expenditure is reasonably constant throughout the *Regulatory Control Period*.

The methodology used by Aurora to develop the forecast projects is set out in the Management Plan 2011 – Customer Initiated Capital Works.

The anticipated works are based on trend analysis and econometric forecasted drivers.

Customer initiated major works

There are 20 line items across the *Regulatory Control Period* with a total value of $16.4 million. The profile of expenditure reduces slightly throughout the *Regulatory Control Period*. The largest work category is the Supply High Voltage Ground Major Project with a total value of $13.7 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Customer Initiated Capital Works:

- supply high voltage ground major project.

Management Plan 2011 – Capacity:

- system studies.

The anticipated works are based on trend analysis and econometric forecasted drivers.

Reinforcements

A total of $87.1 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category. This expenditure forecast is for 473 projects of varying types across four subcategories, being:

- distribution substations;
- high voltage feeders;
- low voltage feeders; and
- zone substations.

Distribution substations

There are 21 line items across the *Regulatory Control Period* with a total value of $7.9 million. This subcategory comprises a single work category; low voltage transformer upgrades – capacity. The methodology used by Aurora to develop the forecast projects is set out in Aurora's Management Plan 2011 – Capacity.

High voltage feeders

There are 422 line items across the *Regulatory Control Period* with a total value of $71.4 million. The largest work category within this range relates to HV feeder upgrade – capacity, with a total value of $54.9 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Capacity:

- embedded generation connections;
- HV feeder upgrade – capacity;
- SWER line replacement;
- terminal station feeder connections; and
- zone substation upgrades – capacity high voltage feeders.

Low voltage feeders

There are 10 line items across the *Regulatory Control Period* with a total value of $1.1 million. The profile of expenditure reduces slightly over the *Regulatory Control Period*. This subcategory comprises a single work category; low voltage feeders upgrade – capacity. The methodology used by Aurora to develop the forecast projects is set out in Aurora's Management Plan 2011 – Capacity.

Zone substations

There are 20 projects across the *Regulatory Control Period* with a total value of $6.7 million. The profile of expenditure varies significantly throughout the *Regulatory Control Period*. This subcategory comprises a single work category; zone substation upgrades – capacity. The methodology used by Aurora to develop the forecast projects is set out in Aurora's Management Plan 2011 – Capacity.

Key assumptions

The key assumptions underlying Aurora's demand related capital expenditure forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's Management Plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- the *TEC* will remain in force, and that any replacement will impose similar and not more prescriptive requirements upon Aurora in relation to network augmentations;
- Aurora's processes and systems that are used to identify capacity system risks, and its methodologies that are used to address the higher risks and options provide a prudent method of determining the augmentation work timetable for Aurora's assets;
- Aurora's method of undertaking trend analysis and demand forecasts for customer initiated capital works is a prudent method of determining the works required;
- the unit rates applied to demand related expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to demand related expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to demand related expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

The slowing of the economic conditions within the State has resulted in a significant decrease in capital expenditure from that of the current *Regulatory Control Period*. This expenditure reduction is most evident in the customer initiated subcategory with expenditure anticipated to return to levels experienced during the 2007-08 and 2008-09 years.

There is also a significant reduction in the requirement for zone substation expenditure, within the reinforcements subcategory when, compared to the scale and number of projects undertaken during the current *Regulatory Control Period*.

There is however a significant increase in the requirement for HV feeder augmentations and constructions as works are undertaken during the forthcoming *Regulatory Control Period* to:

- complete HV feeder augmentations associated with the construction of zone substations within the current *Regulatory Control Period*; and
- augment and construct HV feeders in preparation of expected additional zone substation works required within the 2017-22 *Regulatory Control Period*.

Opex/capex interactions

There is a strong relationship between the demand related capital expenditure forecast and:

- the demand management category which relates to operational expenditure to reduce system demand or alleviate demand through non-network alternatives. This is because there is an inverse relationship between capital expenditure on the works required to meet the capacity requirements of Aurora based on normal load forecasts; and expenditure on demand management initiatives and non-network alternatives. Non-network options are only pursued where it is technically and financially viable to do so; and
- the routine maintenance category which relates to operational expenditure on assets in accordance with the network vision, asset management plan and thread management plans. With additional demand related capital expenditure comes a corresponding increase in routine maintenance, as these new assets drive increased quantities of scheduled maintenance activities. There is therefore a direct relationship between growth in the network through customer initiated capital expenditure and maintenance expenditure.

Forecasts

Aurora's forecasts (including escalations and overheads) for demand related capital expenditure for the forthcoming *Regulatory Control Period* are set out in Table 47.

Table 47

Demand related capex

Aurora's demand related capital expenditure					
$2009–10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	54.855	53.842	52.466	54.062	53.542

11.4.3. Non-demand related

Background

Non-demand related capital expenditure is undertaken to minimise cost of supply to the customer whilst:

- maintaining network performance;
- managing business operating risks; and
- complying with regulatory (e.g. *TEC* requirements), contractual, legal and safety responsibilities.

Non-demand related capital expenditure includes projects undertaken in the following categories:

- reliability and quality maintained; and
- reliability and quality improvements.

Expenditure forecasts within this section refer to projects undertaken in the reliability and quality maintained category only. This category comprises 12 subcategories covering assets such as poles, transformers and switchgear.

Drivers

The drivers for this category are:

- customer service requirements;
- reliability requirements;
- management of risk;
- proactive replacement of units based on special audit;
- life cycle requirements;
- compliance with the asset management policy;
- capacity requirements;
- compliance with relevant legislative and safety obligations; and
- environmental obligations.

Methodology to derive forecasts

As noted previously, the volumes and projects for all work categories that underpin this expenditure are located in Aurora's work program. The individual categories within the work program can be referenced to specific sections of Aurora's 2011 management plans, and this section sets out the relevant management plan for each work category listed.

Reliability and quality maintained

A total of $174.2 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category. This expenditure is forecast to be required for 758 projects of varying types across 12 subcategories, being:

- conductors;
- distribution other assets;
- distribution switchgear;
- distribution transformers;
- maintenance services;
- poles;
- pole-top structures;
- other;
- underground cables;
- zone other assets;
- zone switchgear; and
- zone transformers.

Conductors

There are 30 line items across the *Regulatory Control Period* with a total value of $14.6 million. The expenditure profile reduces slightly each year over the *Regulatory Control Period*. The largest work category expenditure relates to replace HV copper conductor with an associated expenditure of $7.2 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan – Overheads System and Structures:

- fire mitigation projects – conductor;
- replace HV copper conductor;
- replace HV GI conductor; and
- replace HV Live line clamps (safety).

The anticipated works are based on the largest work category remaining consistent with Aurora's historical expenditure.

Distribution other assets

There are 138 line items across the *Regulatory Control Period* with a total value of $13.6 million. The expenditure profile slightly decreases over the *Regulatory Control Period*. The largest work category expenditure relates to replace ground mounted substations with an associated expenditure of $8.6 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Ground Mounted Substations:

- address safety and environmental issues in ground mounted substations;
- replace ground mounted substations; and
- upgrade ground mounted earthing.

Management Plan 2011 – Reliability Management:

- install high voltage feeder control, DA and communications overhead fault indicators;
- install high voltage feeder control, DA and communications underground fault; and
- rectification work minor (eg upgrade fuses).

Management Plan 2011 – Power Quality:

- install power quality metering.

Management Plan 2011 – High Voltage Regulators:

- safety and environmental issues in regulators.

The anticipated works are based on Aurora's risk and condition-based approach to asset renewal and maintenance.

Distribution switchgear

There are 122 line items across the *Regulatory Control Period* with a total value of $21.1 million. The expenditure profile is reasonably constant throughout the *Regulatory Control Period*.

The largest work category expenditure relates to replace ground mounted high voltage switchgear with an associated expenditure of $7.2 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Overhead System and Structures:

- fire mitigation projects – switchgear.

Management Plan 2011 – Reliability Management:

- install high voltage feeder control, DA and communications; and
- overhead feeder load transfer.

Management Plan 2011 – Protection and Control:

- install reclosers; and
- install sectionalisers.

Management Plan 2011 – Ground Mounted Substations:

- replace ground mounted high voltage switchgear;
- replace ground mounted low voltage switchgear; and
- replace OH switchgear (safety).

The anticipated works are based on Aurora's risk and condition-based approach to asset renewal and maintenance.

Distribution transformers

There are 126 line items across the *Regulatory Control Period* with a total value of $24.1 million. The expenditure profile is reasonably constant throughout the *Regulatory Control Period*. The largest work category expenditure relates to upgrade transformer (voltage regulation) with an associated expenditure of $10.1 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Power Quality:

- install regulators; and
- upgrade transformer (voltage regulation).

Management Plan 2011 – Reliability Management:

- rectification work multi visit transformers.

Management Plan 2011 – Ground Mounted Substations:

- replace ground mounted transformer.

Management Plan 2011 – High Voltage Regulators:

- replace regulator ground mounted three phase.

Management Plan 2011 – Overheads System and Structures:

- replace transformer earthing;
- replace transformer 'H'-pole structures; and
- replace transformers.

The anticipated works are based on the largest work category remaining consistent with Aurora's historical expenditure.

Services

There are 35 line items across the *Regulatory Control Period* with a total value of $7.8 million. The expenditure profile reduces slightly each year through the *Regulatory Control Period*. The largest work category expenditure relates to replace services overhead and service fuses with an associated expenditure of $7.7 million.

The methodology used by Aurora to develop the forecast projects is set out in the Management Plan 2011 – Connection Assets.

The anticipated works are based on Aurora's historical service related outage information.

Poles

There are 35 line items across the *Regulatory Control Period* with a total value of $39.8 million. This expenditure profile increases throughout the *Regulatory Control Period*. The largest work category expenditure relates to pole replacements with an associated expenditure of $33.3 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Overhead System and Structures:

- pole replacements; and
- pole staking.

The anticipated works are based on Aurora's chosen asset lives.

Pole-top structures

There are 10 line items across the *Regulatory Control Period* with a total value of $0.8 million. This expenditure profile is constant throughout the *Regulatory Control Period*. The single work category expenditure relates to install bird diverters and pole top reconfigurations.

The methodology used by Aurora to develop the forecast projects for each work category is set out in Aurora's Management Plan 2011 – Overheads System and Structures.

The anticipated works are based on Aurora's asset failures and outage information.

Other assets

There are 140 line items across the *Regulatory Control Period* with a total value of $27.3 million. The expenditure profile varies throughout the *Regulatory Control Period*. The largest work category expenditure relates to replace/relocate low voltage overhead (low clearance) with an associated expenditure of $8.4 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Connection Assets:

- meter panels.

Management Plan 2011 – Reliability Management:

- reliability TRIP programs; and
- relocate/alter high voltage feeders overhead.

Management Plan 2011 – Overhead System and Structures:

- replace high voltage feeders (safety);
- replace low voltage feeders (substandard);
- replace/relocate high voltage overhead (low clearance);
- replace/relocate high voltage overhead (vegetation);
- replace/relocate low voltage overhead (building clearances);
- replace/relocate low voltage overhead (low clearance); and
- upgrade access tracks.

Management Plan 2011 – Power Quality:

- upgrade high voltage feeders (voltage regulation); and
- upgrade low voltage feeders (voltage regulation).

The anticipated works are based on Aurora's risk and condition-based approach to asset replacement and maintenance, which targets specific asset failures as opposed to undertaking general replacement.

Underground Cables

There are 100 line items across the *Regulatory Control Period* with a total value of $13.9 million. The expenditure profile is constant throughout the *Regulatory Control Period*. The largest work category expenditure relates to replace low voltage cables underground CONSAC with an associated expenditure of $8.0 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Underground System

- install lightning arrestors;
- replace cables underground – high voltage;
- replace cables underground – low voltage;
- replace low voltage cables underground CONSAC;
- replace terminations – 11kV cast iron potheads;
- replace underground furniture;
- replace/relocate low voltage overhead (building clearances) with underground; and
- undergrounding in special areas projects.

The anticipated works are based on the largest work category remaining consistent with Aurora's historical expenditure.

Zone other assets

There are 10 line items across the *Regulatory Control Period* with a total value of $1.2 million. The expenditure profile varies considerably throughout the *Regulatory Control Period*. The largest work category expenditure relates to replace rural zones with an associated expenditure of $1.0 million.

The methodology used by Aurora to develop the forecast projects is set out in the Management Plan 2011 – Zone Substations.

The anticipated works are based on current condition data, field failure rates and prudent risk management.

Zone switchgear

There are six line items across the *Regulatory Control Period* with a total value of $3.1 million. The expenditure profile varies considerably throughout the *Regulatory Control Period*. The only work category expenditure relates to replace urban/CBD zones switchgear and the highest annual cost for this category is $2.1 million in 2012-13.

The methodology used by Aurora to develop the forecast projects is set out in the Management Plan 2011 – Zone Substations.

The anticipated works are based on current condition data, field failure rates and prudent risk management.

Zone transformers

There are six line items across the *Regulatory Control Period* with a total value of $6.9 million. The expenditure profile varies throughout the *Regulatory Control Period*. The largest work category expenditure relates to replace urban/CBD zone transformers with an associated expenditure of $5.9 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Zone Substations:

- replace rural zones transformers; and
- replace urban/CBD zones transformers.

The anticipated works are derived by Aurora based on current condition data, field failure rates and prudent risk management.

Reliability and quality improvements

Aurora has not forecast any expenditure within this category. Aurora has made this assumption on the basis that all its reliability improvement projects will be completed within the current *Regulatory Control Period* and future expenditure will be required for compliance activities only, with no specific capital investment aimed at substantive improvements in reliability in the forthcoming *Regulatory Control Period*.

Key assumptions

The key assumptions underlying Aurora's non-demand related capital expenditure forecasts are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- the *TEC* will remain in force, and that any replacement will impose similar and not more prescriptive requirements upon Aurora in relation to Non-Demand Related System capital expenditure;
- Aurora's method of assessing forecasts for non-demand related capital expenditure is a prudent method of determining the works required;
- the unit rates applied to non-demand related capital expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to non-demand related capital expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to non-demand related capital expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

Total non-demand related capital expenditure does not differ significantly from that of the current *Regulatory Control Period*. There are however a number of significant changes within the subcategories within the non-demand related capital expenditure category.

Expenditure within the reliability and quality maintained subcategory has increased significantly, whereas expenditure within the reliability and quality improvements subcategory is forecast to be zero. This change represents Aurora's classification of forecast programs as reliability and quality maintained only. This categorisation assumption also means that the forecast expenditure, within each of the subcategories of the reliability and quality maintained subcategory, increases significantly from that of the current *Regulatory Control Period*.

Opex/capex interactions

There is a strong relationship between non-demand related reliability and quality maintenance capital expenditure forecast and:

- the routine maintenance operating expenditure category which relates to operational expenditure on assets in accordance with the network vision, asset management plan and thread management plans. This is because expenditure on replacing assets has an inverse relationship to the amount of routine maintenance required, as these new assets extend the period between and amount of scheduled maintenance required; and
- the non-routine maintenance operating expenditure category which relates to non-routine operational expenditure on assets in accordance with the network vision, asset management plan and thread management plans. Expenditure on replacing assets has an inverse relationship to the amount of non-routine maintenance required, as these new assets reduce the likelihood of, and amount of, unscheduled maintenance required.

Forecasts

Aurora's forecasts (including escalations and overheads) for non-demand related capital expenditure for the forthcoming *Regulatory Control Period* are set out in Table 48.

Table 48

Non-demand related capex

Aurora's non-demand related capital expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	37.136	38.092	38.338	35.792	37.919

11.4.4. Regulatory obligations or requirements

Background

Regulatory obligations or requirements capital expenditure comprises expenditure that is undertaken by Aurora specifically to address legislative requirements. This expenditure comprises four categories relating to Aurora's safety, health, environmental and compliance obligations. As legislative obligations are contained within a variety of Aurora's management plans they are not specifically addressed within this section of *Aurora's Regulatory Proposal*.

Drivers

The drivers for regulatory obligations or requirements capital expenditure are compliance with the legislative obligations placed upon Aurora.

Methodology to derive forecasts

The volumes and projects for all work categories that underpin this expenditure are located in Aurora's work program. The categories within the work program can be referenced to specific sections of Aurora's 2011 management plans and network strategy documents. As legislative obligations are contained within a variety of Aurora's management plans they are not specifically addressed within this section of Aurora's *Regulatory Proposal*.

Regulatory obligations or requirements

A total of $25.7 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category. This expenditure is forecast to be required for 260 line items of varying types across one subcategory; regulatory obligations or requirements. This expenditure profile varies considerably throughout the *Regulatory Control Period*.

The largest work category within regulatory obligations or requirements relates to safety and environmental issues in ground mounted substations with an associated expenditure of $4.6 million across the period.

The methodology used by Aurora to develop the forecast projects for each work category is set out in Aurora's management plans and strategy documents.

- The anticipated works are based on Aurora's compliance with its legislative obligations.

Key assumptions

The key assumptions underlying Aurora's regulatory obligations or requirements capital expenditure works forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's compliance obligations will remain unchanged for the *Regulatory Control Period*;
- Aurora's method of assessing forecasts for regulatory obligations or requirements capital expenditure is a prudent method of determining the works required;
- the costs associated with regulatory obligations or requirements capital expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to regulatory obligations or requirements capital expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to regulatory obligations or requirements capital expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

There are no instances where expenditure differs significantly from that of the current *Regulatory Control Period*.

Opex/capex interactions

There is a relationship between regulatory obligations or requirements capital expenditure and other capital expenditure categories, and operational expenditure, as new regulatory requirements will typically result in changed practices for both capital and operating expenditure.

Forecasts

Aurora's forecasts (including escalations and overheads) for regulatory obligations or requirements capital expenditure for the forthcoming *Regulatory Control Period* are set out in Table 49.

Table 49

Regulatory obligations or requirements

Aurora's regulatory obligations or requirements capital expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	5.515	5.484	5.230	5.152	5.043

11.4.5. Non-network

Background

Non-network capital expenditure comprises five categories of shared expenditure, being:

- other;
- IT and communications;
- motor vehicles;
- plant and equipment; and
- property.

Non-system capital expenditure includes a component of Aurora's distribution network IT strategy. This strategy is a 10 year plan that achieves technology consolidation and simplification and enhanced strategic capabilities. This strategy is based on firstly implementing a foundation to enable Aurora's distribution business to thrive in a "smart world". The second stage addresses market facing capabilities. The strategy realises a long term vision that transforms Aurora's IT capabilities from their current state into a strategic, business enabling platform.

The final four categories of this expenditure relate to corporate and shared costs which are allocated across Aurora on an organisation-wide level through the capital expenditure ICAM. As the portion allocated to Network Services division is already included in the capitalised overheads component of expenditure, this section only discusses the component of these costs that is allocated to the Network division.

Aurora distribution network ISG strategy

Aurora is responsible for the management, operation and development of electricity distribution assets across Tasmania and as such uses a wide range of IT systems, applications and tools. These items are critical to discharging Aurora's responsibilities, many of which are critical to the short and long-term effectiveness and efficiency of the distribution business.

This section summarises the Distribution Network ISG Strategy[6] which broadly constitutes strategies for:

- the Network division IT group which is responsible for what will be done; and
- the Information Services Group (ISG) which is responsible for how it will be done.

It is noted that the Distribution Network ISG Strategy is influenced by the Aurora Business Strategy, the Distribution Business Strategy, the Corporate IT Strategy and the expectations of a diverse group of key stakeholders including customers, Aurora's shareholder, technical and economic regulators, employees and the public.

Key influences over the 2012-17 *Regulatory Control Period* include the:

- Aurora Business Strategy;
- distribution Business Strategy;
- Tasmanian State Government as owner; and
- economic and technical Regulators.

Future state vision

The goal of the Distribution Network ISG Strategy is to enable and support the distribution business' aspirational goal "To not contribute to any price increases to the customer as a result of its efforts" over the 2012-17 *Regulatory Control Period*. In order to achieve this, Aurora's distribution business will undergo a significant transformation.

To achieve this future state vision, Aurora will require a significant injection of funds over the forthcoming *Regulatory Control Period*. These funds significantly exceed those required for the current *Regulatory Control Period*, and incur a significant portion of the Network division's shared costs.

Aurora had developed a comprehensive schedule of projects based on business requirements derived from the Aurora IT Strategy 2009 – 2012 and the Marchment Hill IT Strategy Review (Marchment Hill Review). Built from the "bottom-up", this "organic" program of work, comprising 130 plus projects, was analysed and reviewed by external consultants, paying specific attention to the impact on Aurora's enterprise architecture. Enterprise Architects Pty Ltd (Enterprise Architects) was engaged by Aurora to perform this architectural analysis and to develop its enterprise architecture based IT strategy for Aurora's distribution business. This was achieved through an iteration of the open group architecture framework (TOGAF), architecture development method (ADM) to create current state/transition states/ target state road maps of the proposed projects revealing their impact on business capability and application architecture.

Whilst the bottom-up method addressed the issues raised in the Marchment Hill Review, there was no overarching architectural strategic design underpinning the program. From an architectural perspective, any investment should be built on an IT strategy that is aligned to business strategy. This required an alternative hypothesis to be developed using a "top-down" approach with the specific aims of reducing complexity and improving capabilities critical to strategic business execution.

6 Aurora Energy Distribution Network ISG Strategy 2012-2017, Final Version 1, 15 March 2011.

This alternative hypothesis was selected by an executive steering committee and approved by Aurora's Board as the preferred option forming the basis of the Aurora strategy.

The benefits of the strategic "top-down" approach are:

- reduced complexity;
- improved capabilities;
- partnerships with best practice thought leaders;
- the creation of strategic assets that are scalable, sustainable and extensible;
- improved operational efficiencies;
- improved network asset efficiency;
- increased re-use of capabilities across the business;
- improved security and reliability ensures integrity and safety of company data assets;
- improved use of capital;
- solid benchmarking against industry best practice will guide Aurora to potential improvements and future strategies;
- an ability to do more with less; and
- to enable longer-term planning.

Drivers

Non-network capital expenditure typically provides support services for the other `network' expenditure classifications. As a consequence, the drivers are numerous and diverse, and are not set out in this section.

Methodology to derive forecasts

For non-system capital expenditure the volumes and projects for all work categories that underpin this are located in Aurora's work program. The individual categories within the work program can be referenced to specific sections of Aurora's 2011 management plans and network strategy documents, and this section sets out the relevant plan and strategy for each work category listed.

For corporate and shared costs (the remaining four cost categories within non-network capital expenditure), the volumes and projects for the activities that underpin this expenditure are forecast by Aurora's corporate team. These forecasts are built up with regard to both corporate wide strategies and parameters; and forecasts and planning considerations by each division and subsidiary within Aurora. The costs are allocated to the distribution business using Aurora's ICAM on the basis of the most appropriate driver.

Other

A total of $2.9 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category spread over 10 line items across one overall subcategory; other. This expenditure profile is consistent throughout the *Regulatory Control Period*.

IT and communications

A total of $46.3 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category spread over 10 line items across one overall subcategory; IT and communications. This expenditure profile varies moderately throughout the *Regulatory Control Period*.

The only work category expenditure relates to IT software – general and the methodology used by Aurora to develop the forecast projects above is based on implementing the initiatives in the Distribution Network IT Strategy[7].

Motor vehicles

A total of $25.3 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category spread over five line items across one overall subcategory; motor vehicles. This profile of expenditure decreases significantly over the *Regulatory Control Period*.

The only work category expenditure relates to motor vehicles and the methodology used by Aurora to develop the forecast projects above is based on implementing the initiatives in the Aurora Fleet Asset Management Plan.

Plant and equipment

Aurora has not forecast any expenditure within this category for the *Regulatory Control Period*.

Property

A total of $2.3 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category spread over five line items across one overall subcategory; property. This profile of expenditure is static over the *Regulatory Control Period*.

The only work category expenditure relates to property and the methodology used by Aurora to develop the forecast projects above is based on implementing the initiatives in the Aurora Property and Accommodation Strategy and the Facilities Management Plan.

Key assumptions

The key assumptions underlying Aurora's non-network capital expenditure works forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- Aurora's overall organisation-wide strategies and plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's ICAM provides an appropriate method for apportioning corporate and shared costs to the distribution business;
- Aurora's method of assessing forecasts for other non-system capital expenditure is a prudent method of determining the works required;
- the unit rates applied to other non-system capital expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to other non-system capital expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to other non-system capital expenditure will be the same as the out-turn costs faced by Aurora.

7 Ibid.

Expenditure variations

There are significant variations in the expenditure forecasts for non-network capital expenditure from that of the current *Regulatory Control Period*.

Expenditure within the IT and communications subcategory is forecast to decrease significantly due to the completion of the NEM and contestability related capital projects undertaken during the current *Regulatory Control Period*. Aurora has forecast that no expenditure will be required for NEM related activities in the forthcoming *Regulatory Control Period*.

There are no instances where expenditure differs significantly from that of the current *Regulatory Control Period* for the other subcategories within the non-network subcategory.

Opex/capex interactions

There is a general interaction between the non-network capital expenditure discussed in this chapter and operating costs as the greater expenditure is in this category, the more resourcing is needed to maintain the assets such as IT, fleet and property.

Forecasts

Aurora's forecasts (including escalations and overheads) for non-network capital expenditure for the forthcoming *Regulatory Control Period* are set out in Table 50.

Table 50

Non-network capex

Aurora's non-network capital expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	17.737	14.712	13.033	15.164	15.155

11.4.6. SCADA and network control

Background

SCADA and network control expenditure relates to capital expenditure on Aurora's supervisory control and data acquisition (SCADA) system; as well as expenditure on associated network control activities.

SCADA systems are functionally rich and fully integrated solutions that improve fault management, outage analysis, operations dispatch, crew management, switching order development, safety documentation, and reporting network operations; whilst also managing assets, monitoring real-time performance and delivery security, and providing alerts regarding outage situations.

A large component of this expenditure relates to implementing new SCADA software that will assist Aurora to:

- safeguard its employees and the public;
- improve restoration time and efficiency; and
- reduce the costs, risks, and uncertainties of energy distribution operations.

Drivers

The key driver for this category is security of supply through visibility of network conditions and network operability.

Methodology to derive forecasts

As noted previously, the volumes and projects for all work categories that underpin this expenditure are located in Aurora's work program. The categories within the work program can be referenced to specific sections of Aurora's 2011 management plans and network strategy documents, and this section sets out the relevant plan and strategy for each work category listed.

SCADA and network control

A total of $14.1 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category. This expenditure is forecast to be required for 22 line items of varying types across one subcategory; SCADA and network control. This expenditure profile varies considerably throughout the *Regulatory Control Period*.

The largest work category within SCADA and network control relates to IT software – SCADA with an associated expenditure of $11.5 million across the period.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Reliability:

- install high voltage feeder control, data acquisition and communications – underground automation.

Distribution Network IT Strategy[8]:

- IT software – SCADA.
- The anticipated works are based on implementing the initiatives in the Network IT Strategy.

Key assumptions

The key assumptions underlying Aurora's SCADA and network control capital expenditure works forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's SCADA and network control work practices will proceed as planned for the *Regulatory Control Period*;
- Aurora's method of assessing forecasts for SCADA and network control capital expenditure is a prudent method of determining the works required;.
- the costs associated with SCADA and network control capital expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to SCADA and network control capital expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to SCADA and network control capital expenditure will be the same as the out-turn costs faced by Aurora.

8 Ibid.

Expenditure variations

There are significantly increases from that of the current *Regulatory Control Period* resulting from the implementation of the Distribution Network ISG Strategy.

Opex/capex interactions

There is a strong relationship between SCADA and network control capital expenditure and operational expenditure as new SCADA systems allow for the efficient identification, diagnosis, planning and rectification of faults. This minimises operational expenditure in areas including labour costs, spare parts and inventory holdings.

Forecasts

Aurora's forecasts (including escalations and overheads) for SCADA and network control capital expenditure for the forthcoming *Regulatory Control Period* are set out in Table 51.

Table 51

SCADA and network control capex

Aurora's SCADA and network control capital expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	1.157	5.762	5.766	0.715	0.707

11.5. Total capital expenditure

Aurora's forecasts (including escalations and overheads) for capital expenditure for the forthcoming *Regulatory Control Period* are set out in Table 52.

Table 52

Total capex

Aurora's total capital expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Capitalised overheads					
Capitalised overheads	20.506	20.606	19.850	19.383	19.565
System					
Demand related	54.855	53.842	52.466	54.062	53.542
Non-demand related	37.136	38.092	38.338	35.792	37.919
Regulatory obligations or requirements	5.515	5.484	5.230	5.152	5.043
Non system					
Non-network	17.737	14.712	13.033	15.164	15.155
SCADA and network control	1.157	5.762	5.766	0.715	0.707
Total expenditure	**136.906**	**138.498**	**134.683**	**130.268**	**131.931**

Aurora's actual and forecast for *Standard Control Services* capital expenditure for the current and forthcoming *Regulatory Control Periods* is set out in Table 53.

Table 53

Capital expenditure

Aurora's capital expenditure	Actual			Forecast						
$2009-10	2007-08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Total expenditure	116.598	139.108	148.603	162.105	139.452	136.906	138.498	134.683	130.268	131.931
OTTER proposed	85.716	131.430	129.067	124.599	122.533					

12. Operating Expenditure

12. Operating expenditure

12.1. Rules requirements

Clause 6.12.3(a) of the *Rules* provides that the AER may accept or approve, or refuse to accept or approve, any element of Aurora's *Regulatory Proposal*. This means the AER may either accept or approve Aurora's total operating expenditure forecasts, or refuse to accept or approve Aurora's total operating expenditure forecasts on the basis of information provided in this *Regulatory Proposal*.

Clause 6.12.1(4) of the *Rules* provides that where the AER refuses to accept or approve Aurora's operating expenditure forecasts it must set out its reasons for that decision and its own estimate of the total of Aurora's required total operating expenditure for the 2012-17 *Regulatory Control Period*. In reaching a decision the AER must be satisfied that the forecast reflects the operating expenditure criteria, and have regard to the operating expenditure factors.

Clause 6.5.6(a) of the *Rules* requires that Aurora's building block proposal must include the total forecast operating expenditure for the 2012-17 *Regulatory Control Period*, which it considers meets each of the operating expenditure objectives. These objectives are to:

(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) maintain the quality, reliability and security of supply of *Standard Control Services*; and

(4) maintain the reliability, safety and security of the distribution system through the supply of *Standard Control Services*.

Clause 6.5.6(b) of the *Rules* requires that Aurora's operating expenditure forecast must:

(1) comply with the requirements of any relevant regulatory information instrument;

(2) be for expenditure that is properly allocated to *Standard Control Services* in accordance with the principles and policies set out in Aurora's Cost Allocation Method;

(3) include both:

  (i) the total of the forecast operating expenditure for the 2012-17 *Regulatory Control Period*; and

  (ii) include the forecast of the operating expenditure for each *Regulatory Year* of the 2012-17 *Regulatory Control Period*.

Clause 6.5.6(c) of the *Rules* requires that the AER accept Aurora's forecast of required operating expenditure if it is satisfied that the total of the forecast operating expenditure for the *Regulatory Control Period* reasonably reflects the operating expenditure criteria. The operating expenditure criteria require that the forecast reflect:

(1) the efficient costs of achieving the operating expenditure objectives;

(2) the costs that a prudent operator in Aurora's circumstances would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Clause 6.5.6(e) of the *Rules* sets out 10 operating expenditure factors which reflect the matters which the AER must have regard to in determining its satisfaction that the forecast operating expenditure for the 2012-17 *Regulatory Control Period* reasonably reflects the operating expenditure criteria.

Further, schedule 6.1.2 of the *Rules* requires that Aurora set out the following information and matters relating to operating expenditure:

(1) a forecast of the required operating expenditure that complies with the requirements of clause 6.5.6 of the *Rules* and identifies the forecast operating expenditure by reference to well accepted categories such as:

  (i) particular programs; or

  (ii) types of operating expenditure (e.g. maintenance, payroll, materials etc),

and identifies in respect of each such category:

  (i) to what extent that forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable; and

  (ii) the categories of distribution services to which that forecast expenditure relates;

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

(3) the forecasts of key variables relied upon to derive the operating expenditure forecast and the method used for developing those forecasts of key variables;

(4) the method used for determining the cost associated with planned maintenance programs designed to improve the performance of the relevant distribution system for the purposes of any service target performance incentive scheme that is to apply to Aurora in respect of the relevant *Regulatory Control Period*;

(5) the key assumptions that underlie the operating expenditure forecast;

(6) a certification of the reasonableness of the key assumptions by the directors of Aurora;

(7) operating expenditure for each of the past *Regulatory Years* of the previous and current *Regulatory Control Period*, and the expected operating expenditure for each of the last two *Regulatory Years* of the current *Regulatory Control Period*, categorised in the same way as for the operating expenditure forecast; and

(8) an explanation of any significant variations in the forecast operating expenditure from historical operating expenditure.

In this chapter, Aurora will demonstrate its compliance with the operating expenditure criteria by demonstrating that the:

- identified scope is consistent with Aurora's regulatory obligations and with standard industry practice in meeting the operating expenditure objectives;
- demand and cost inputs have been either forecast or reviewed by independent expert third parties and determined to be realistic;
- scoping processes are reasonable and utilise realistic demand inputs, resulting in a prudent operating expenditure scope that has been reviewed and assessed by independent expert third parties where possible;
- costing processes are reasonable and incorporate realistic cost inputs, resulting in an efficient operating expenditure forecast; and
- identified scope can be delivered by Aurora.

Further, where expenditure differs significantly from that of the current *Regulatory Control Period*, such differences are explained.

12.2. 1 January 2004 – 31 December 2007

This section of Aurora's *Regulatory Proposal* will focus on the historic operating expenditure for the previous *Regulatory Control Period* (1 January 2004 – 31 December 2007).

Aurora has broken its operating expenditure into the categories that have been historically utilised by OTTER as part of its regulation of Aurora:

- network divisional management;
- network asset maintenance;
- emergency and fault response;
- system operations;
- vegetation management;
- NEM and contestability related; and
- corporate and shared services.

An analysis for each category is provided in the following sections.

The AER should note that this *Regulatory Control Period* is characterised by calendar year analysis.

12.2.1. Network divisional management

Network divisional management expenditure refers to operating expenditure incurred in the day to day business operations of the distribution business. It therefore includes costs such as the:

- Network division staff and their associated costs;
- application of the GSL scheme; and
- cost of levies that are imposed by legislation.

Background

There are a number of administrative, commercial and engineering staff within the Network division of Aurora that are charged with the operations of the distribution business. These staff provide the support services that are required to undertake the operations, maintenance and construction of Aurora's distribution network.

Where staff labour costs can be directly allocated to distribution activities, they are allocated to those activities. Those costs that remain unallocated are captured within the network divisional management costs.

Aurora is required to make payments to customers in accordance with the provisions of OTTER's GSL scheme. These payments are captured within the network divisional management costs.

Aurora also incurs costs in accordance with levies that are imposed in accordance with State Government legislation. These payments are also captured within the network divisional management costs.

Results

Aurora's results for network divisional management expenditure for the previous *Regulatory Control Period* are set out in Table 54.

Aurora had consistent departures from the OTTER proposed expenditure during this *Regulatory Control Period*. This was due to an increased focus on strengthening the engineering capability of the business.

Table 54

Network divisional management opex

Aurora's network divisional management operating expenditure				
$2009-10	2004 ($m)	2005 ($m)	2006 ($m)	2007 ($m)
Actual	16.786	17.483	16.529	15.956
OTTER's proposed	15.190	14.952	14.645	14.885

12.2.2. Network asset maintenance

Network asset maintenance expenditure refers to operating expenditure related to:

- corrective maintenance; and
- preventative maintenance.

Corrective maintenance encompasses repair and replacement work that is undertaken after an issue has been identified during an inspection cycle.

Preventative maintenance encompasses repair and replacement work that is undertaken on a predetermined cycle. This type of maintenance is generally influenced by known failure rates and causes; and asset condition information obtained from maintenance inspections.

Background

Asset inspection programs are undertaken to identify asset defects that are then repaired within the corrective and routine maintenance programs. These programs are designed to ensure that assets remain in an operable condition. Defects may also be identified during routine maintenance or through ad hoc inspection and operation of the system.

Asset defects range from issues that pose an immediate threat to safety or supply to issues that may over time cause the assets to deteriorate more quickly than desired.

Asset management outcomes

This expenditure reduces the risk the assets pose to the business and also reduces the incidence of fault expenditure through the maintenance and repair of assets.

Results

Aurora's results for network asset management expenditure for the previous *Regulatory Control Period* are set out in Table 55.

Aurora had significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Aurora has maintained expenditure at consistent levels throughout this *Regulatory Control Period* and this has resulted in an under-expenditure when compared to the OTTER proposed allowance.

Table 55

Network asset maintenance opex

Aurora's network asset maintenance operating expenditure				
$2009-10	2004 ($m)	2005 ($m)	2006 ($m)	2007 ($m)
Actual	9.838	10.963	10.514	9.463
OTTER's proposed	15.027	14.188	13.372	12.893

12.2.3. Emergency response and repair

Emergency response and repair expenditure refers to operating expenditure to reactively respond to unscheduled events on the distribution network including storms, bushfires, unplanned outages and third party contact events.

Background

Expenditure is driven in response to the occurrence of asset failure events impacting the safe and reliable supply of electricity. Notification of the vast majority of these events occurs via calls to Aurora's 24-hour emergency line.

Asset management outcomes

Emergency response and repair expenditure ensures the prompt restoration and ongoing continuity of supply; any asset management outcomes are secondary to the safe and secure supply of electricity.

Results

Aurora's results for emergency response and repair expenditure for the previous *Regulatory Control Period* are set out in Table 56.

Aurora had significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Aurora's expenditure in this area has been consistently higher than that proposed by both Aurora and OTTER for this *Regulatory Control Period*.

Table 56

Emergency response and repair opex

Aurora's emergency response and repair operating expenditure				
$2009-10	2004 ($m)	2005 ($m)	2006 ($m)	2007 ($m)
Actual	9.816	11.481	12.391	11.941
OTTER's proposed	8.932	8.478	8.056	7.729

12.2.4. System operations

System operations expenditure refers to operating expenditure for the real time management of the distribution network and provision of dynamic system supervision.

Background

This expenditure reflects the efficient costs required to maintain and manage the operational security of the distribution network, primarily Aurora's distribution operations fault centre which operates 24 hours per day.

Asset Management Outcomes

The operations of the distribution operations and fault centre ensure the safety of customers and manage the response and rectification works on the distribution network.

Results

Aurora's results for system operations expenditure for the previous *Regulatory Control Period* are set out in Table 57.

Aurora had significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Aurora's expenditure in this area has been consistently higher than that proposed by both Aurora and OTTER for this *Regulatory Control Period*.

Table 57

System operations opex

Aurora's system operations operating expenditure				
$2009–10	2004 ($m)	2005 ($m)	2006 ($m)	2007 ($m)
Actual	2.014	1.992	1.929	2.540
OTTER's proposed	0.177	0.184	0.182	0.180

12.2.5. Vegetation management

Vegetation management expenditure refers to operating expenditure that is undertaken to ensure the minimisation of interaction between vegetation and flora; and the distribution network. This expenditure was undertaken as a preventative measure in accordance with the provisions of the *TEC*.

Background

Aurora's vegetation management program's main drivers were to:

- ensure compliance with the *TEC*; and
- control vegetation interaction with the distribution network to minimise the chance of fire-start and supply interruptions.

Vegetation management is a preventative measure that also formed a key part of Aurora's bushfire mitigation program.

Asset management outcomes

During this period, vegetation management plans were expanded to include further works in the areas of:

- supply reliability;
- safety; and
- infrastructure access.

Aurora therefore increased expenditure above that originally proposed for the *Regulatory Control Period* to ensure satisfactory outcomes were achieved.

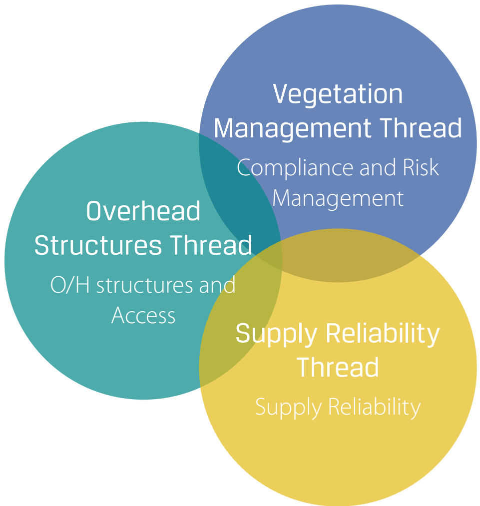
The model for the vegetation management program is represented as a program that operated across three separate threads of:

- vegetation management;
- supply reliability; and
- overhead system and structures.

Each thread not only has a different driver for actioning the works, but also requires the works to be undertaken to a different standard than that referred to in *TEC*; and therefore requires the use of different work methods and practices. This interaction is shown in Figure 35.

Figure 35

Vegetation management model



For example:

- **The Vegetation Management Thread** – exists predominately for the purposes of bushfire risk management and TEC compliance. This is the area that forms the bulk of the cyclic works undertaken.
- **The Supply Reliability Thread** – includes the requirement for vegetation clearing pertaining to reliability of supply issues. This work includes clearing/maintaining vegetation up to and greater than the *TEC* requirement. Aurora's feeder trunk strategy works required a higher level of maintenance and concentrated on the high voltage distribution network.
- **The Overhead System and Structures Thread** – includes vegetation issues pertaining to the development and maintenance of tracks to provide access for inspections and fault response.

Results

Aurora's results for vegetation management expenditure for the previous *Regulatory Control Period* are set out in Table 58.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 58

Vegetation management opex

Aurora's vegetation management operating expenditure				
$2009–10	2004 ($m)	2005 ($m)	2006 ($m)	2007 ($m)
Actual	6.210	6.078	5.996	6.225
OTTER's proposed	5.948	5.577	5.522	5.465

12.2.6. NEM and contestability related

NEM and contestability related expenditure refers to operating expenditure relating to Aurora's participation in the National Electricity Market and the establishment of retail contestability within the State. It comprises two key categories of expenditure:

- the establishment of IT systems (including allocations from the corporate divisions of Aurora); and
- the additional resources required by Aurora to establish and operate market systems.

Background

There are a number of business activities within Aurora that are undertaken within the distribution business as a direct consequence of Aurora's participation within the NEM and the introduction of retail contestability by the State Government. Key to these business activities are NEM compliant IT systems and associated software charges; and the key resources to undertake the additional functions required within the distribution business.

Results

Aurora's results for NEM and contestability related expenditure for the previous *Regulatory Control Period* are set out in Table 59.

Aurora had significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Whilst Aurora's expenditure pattern may be inconsistent with OTTER's proposed expenditure, the uncertain nature of the expenditure was recognised by OTTER and an adjustment mechanism was included within Aurora's 2003 Determination to account for these variations.

Table 59

NEM and contestability related opex

Aurora's NEM and contestability related operating expenditure				
$2009-10	2004 ($m)	2005 ($m)	2006 ($m)	2007 ($m)
Actual	1.889	1.920	2.295	3.303
OTTER's proposed	1.941	1.540	1.240	1.202

12.2.7. Corporate and shared services

Corporate and shared services expenditure refers to operating expenditure incurred for the provision of corporate activities and shared services such as information systems. It therefore includes:

- costs for such functions as:
  - human resources functions;
  - treasury and finance operations;
  - legal advice and assistance;
- operations of the CEO's office; and
- costs for the operations of enterprise information systems such as payroll and finance.

These costs are allocated to the respective users of these services via Aurora's indirect cost allocation method (ICAM).

Background

There are a number of business activities within Aurora that are undertaken at a corporate, or shared services level to achieve economies of scale and greater efficiencies than would naturally occur if the activities were undertaken within the individual divisions of Aurora. This is also true for the provision of key information systems such as payroll and finance; and the Aurora IT network.

Results

Aurora's results for corporate and shared services expenditure for the previous *Regulatory Control Period* are set out in Table 60.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 60

Corporate and shared services opex

Aurora's corporate and shared services operating expenditure				
$2009-10	2004 ($m)	2005 ($m)	2006 ($m)	2007 ($m)
Actual	7.262	6.908	8.950	9.630
OTTER's proposed	8.522	8.373	8.289	8.264

12.3. 1 January 2008 – 30 June 2012

This section of Aurora's *Regulatory Proposal* will focus on the actual and forecast operating expenditure for the current *Regulatory Control Period* (1 January 2008 – 30 June 2012).

Aurora has broken its operating expenditure into the categories that have been historically utilised by OTTER as part of the current economic regulation of Aurora:

- network divisional management;
- network asset maintenance;
- emergency and fault response;
- system operations;
- vegetation management;
- NEM and contestability related;
- corporate and shared services; and
- connection asset repairs.

An analysis for each category is provided in the following sections.

The AER should note that this *Regulatory Control Period* is characterised by a change from calendar year to financial year. This change was effected by means of a six month only period at the commencement of the *Regulatory Control Period*.

12.3.1. Network divisional management

Network divisional management expenditure refers to operating expenditure incurred in the day to day business operations of the distribution business. It therefore includes the:

- Network division staff and their associated costs;
- application of the GSL scheme; and
- cost of levies that are imposed by legislation.

Background

There are a number of administrative, commercial and engineering staff within the Network division of Aurora that are charged with the operations of the distribution business. These staff provide the support services that are required to undertake the operations, maintenance and construction of Aurora's distribution network.

Where staff labour costs can be directly allocated to distribution activities, they are allocated to those activities. Those costs that remain unallocated are captured within the network divisional management costs.

Aurora is required to make payments to customers in accordance with the provisions of OTTER's GSL scheme. These payments are captured within the network divisional management costs.

Aurora also incurs costs in accordance with levies that are imposed in accordance with State Government legislation. These payments are also captured within the network divisional management costs.

Results

Aurora's results/forecasts for network divisional management expenditure for the current *Regulatory Control Period* are set out in Table 61.

With the exception of the period from 1 January 2008 to 30 June 2009 Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Lower than anticipated expenditure has occurred in the first eighteen months of the Regulatory Control Period as Aurora continued to increase its engineering capability within the distribution business.

Table 61

Network divisional management opex

Aurora's network divisional management operating expenditure					
$2009–10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual	8.060	16.137	22.783	22.819	21.916
OTTER's proposed	10.417	21.128	21.981	23.522	21.915

12.3.2. Network asset maintenance

Network asset maintenance expenditure refers to operating expenditure related to:

- corrective maintenance; and
- preventative maintenance.

Corrective maintenance encompasses repair and replacement work that is undertaken after an issue has been identified during an inspection cycle.

Preventative maintenance encompasses repair and replacement work that is undertaken on a predetermined cycle. This type of maintenance is generally influenced by known failure rates and causes; and asset condition information obtained from maintenance inspections.

Background

Asset inspection programs are undertaken to identify asset defects that are then repaired within the corrective and routine maintenance programs. These programs are designed to ensure that assets remain in an operable condition. Defects may also be identified during routine maintenance or through ad hoc inspection and operation of the system.

Asset defects range from issues that pose an immediate threat to safety or supply to issues that may over time cause the assets to deteriorate more quickly than desired.

Asset management outcomes

This expenditure reduces the risk the assets pose to the business and also reduce the incidence of fault expenditure through the maintenance and repair of assets.

Results

Aurora's results/forecasts for network asset management expenditure for the current *Regulatory Control Period* are set out in Table 62.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 62

Network asset maintenance opex

Aurora's network asset maintenance operating expenditure					
$2009–10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual	4.443	11.071	12.842	13.029	12.389
OTTER's proposed	6.154	12.614	12.930	13.258	13.575

12.3.3. Emergency and fault response

Emergency response and repair expenditure refers to operating expenditure to reactively respond to unscheduled events on the distribution network including storms, bushfires, unplanned outages and third party contact events.

Background

Expenditure is driven in response to the occurrence of asset failure events impacting the safe and reliable supply of electricity. Notification of the vast majority of these events occurs via calls to Aurora's 24-hour emergency line.

Asset management outcomes

Emergency response and repair expenditure ensures the prompt restoration and ongoing continuity of supply; any asset management outcomes are secondary to the safe and secure supply of electricity.

Results

Aurora's results/forecasts for emergency and fault response expenditure for the current *Regulatory Control Period* are set out in Table 63.

Aurora had significant departures from the OTTER proposed expenditure during this *Regulatory Control Period.* Aurora's expenditure in this area has been consistently higher than that proposed by both Aurora and OTTER for this *Regulatory Control Period*. During the 2009-10 year Aurora also experienced severe weather and storm conditions resulting in unanticipated expenditure related to fault rectification work.

Table 63

Emergency and fault response opex

Aurora's emergency and fault response operating expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual	6.082	13.711	17.350	14.307	13.853
OTTER's proposed	5.487	11.116	11.258	11.400	11.542

12.3.4. System operations

System operations expenditure refers to operating expenditure for the real time management of the distribution network and provision of dynamic system supervision.

Background

Expenditure reflects the costs required to maintain and manage the operational security of the distribution network, primarily Aurora's distribution operations and fault centre, which operate 24 hours per day.

Asset management outcomes

The operations of the distribution operations and fault centre ensure the safety of customers and manage the response and rectification.

Results

Aurora's results/forecasts for system operations expenditure for the current *Regulatory Control Period* are set out in Table 64.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period.*

Table 64

System operations opex

Aurora's system operations operating expenditure					
$2009-10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual	1.597	3.903	3.695	3.986	3.055
OTTER's proposed	1.967	4.044	4.580	4.689	4.798

12.3.5. Vegetation management

Vegetation management expenditure refers to operating sexpenditure that is undertaken to ensure the minimisation of interaction between vegetation and flora; and the distribution network. This expenditure was undertaken as a preventative measure in accordance with the provisions of the *TEC*.

Background

Aurora's vegetation management program is designed to:

- comply with the *TEC*;
- control vegetation interaction with the network to minimise the chance of fire-start;
- ensure safety for employees and the public;
- improve network reliability;
- satisfy customers and stakeholders.

A review of the *TEC* in October 2007 resulted in the vegetation code (Chapter 8A) having its advisory status removed; meaning compliance became mandatory through the usual application of the *TEC*.

Aurora proposed a cost increase to achieve compliance as part of its submission for the *Regulatory Control Period*. The cost increases were predominantly aimed at the management of 'overhang' in 'high' and 'very high' fire risk areas and increasing the removal of such occurrences.

Aurora also considered that the quality of data available regarding vegetation clearing workloads and forecasts was poor and would need to improve prior to development of future work forecasts for the 2012-17 *Regulatory Control Period*.

Resulting changes to data capture systems during the *Regulatory Control Period* have led to significantly improved quality and level of information. This information has provided key inputs into the cost/resource modelling used to quantify Aurora's requirements for the 2012-17 *Regulatory Control Period*.

Asset management outcomes

Whilst improvements have been identified in all target areas of the vegetation management program, instances of vegetation causing faults still remains a concern to Aurora.

Results

Aurora's results/forecasts for vegetation management expenditure for the current *Regulatory Control Period* are set out in Table 65.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 65

Vegetation management opex

Aurora's vegetation management operating expenditure					
$2009–10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual	3.239	8.299	8.682	8.454	8.088
OTTER's proposed	4.000	8.690	8.416	8.252	8.460

12.3.6. NEM and contestability related

NEM and contestability related expenditure refers to operating expenditure relating to Aurora's continued participation in the National Electricity Market and the establishment of further tranches of retail contestability within the State. It comprises two key categories of expenditure:

- the establishment of IT systems (including allocations from the corporate divisions of Aurora); and
- the additional resources required by Aurora to establish and operate market systems.

Background

There are a number of business activities within Aurora that are undertaken within the distribution business as a direct consequence of Aurora's participation within the NEM and the introduction of retail contestability by the State Government. Key to these business activities are NEM compliant IT systems and associated software charges; and the key resources to undertake the additional functions required within the distribution business.

Results

Aurora's results/forecasts for NEM and contestability related expenditure for the current *Regulatory Control Period* are set out in Table 66.

Aurora had significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*. Whilst Aurora's expenditure pattern may be inconsistent with OTTER's proposed expenditure, the uncertain nature of the expenditure was recognised by OTTER and an adjustment mechanism was included within Aurora's 2007 Determination to account for these variations.

Table 66

NEM and contestability related opex

Aurora's NEM and contestability related operating expenditure					
$2009–10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual	1.767	5.601	5.621	5.180	3.906
OTTER's proposed	1.257	3.334	4.208	4.317	4.864

12.3.7. Corporate and shared services

Corporate and shared services expenditure refers to operating expenditure incurred for the provision of corporate activities and shared services such as information systems. It therefore includes:

- costs for such functions as:
  - human resources functions;
  - treasury and finance operations;
  - legal advice and assistance; and
- operations of the CEO's office; and
- costs for the operations of enterprise information systems such as payroll and finance.

These costs are allocated to the respective users of these services via Aurora's ICAM.

Background

There are a number of business activities within Aurora that are undertaken at a corporate, or shared services, level to achieve economies of scale and greater efficiencies than would naturally occur if the activities were undertaken within the individual divisions of Aurora. This is also true for the provision of key information systems such as payroll and finance; and the Aurora IT network.

Results

Aurora's results/forecasts for corporate and shared services expenditure for the current *Regulatory Control Period* are set out in Table 67.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 67

Corporate and shared services opex

Aurora's corporate and shared services operating expenditure					
$2009–10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual	4.223	9.497	9.143	11.052	11.308
OTTER's proposed	5.279	10.318	10.679	11.214	11.335

12.3.8. Connection asset repairs

Connection asset repairs expenditure refers to operating expenditure associated with assets such as meter panels and ancillary equipment (fuses, switches and timeclocks, etc) and metering transformers.

Background

The expenditure during the *Regulatory Control Period* is associated with the following drivers:

- safety; and
- replacement of aged and poor condition assets that fail in service.

Asset management outcomes

Failure rates of connection assets have remained stable over this period indicating the overall condition of this asset class is not deteriorating. This program is expected to continue unchanged over the next period in line with the stable conditions of the connection assets.

Results

Aurora's results/forecasts for connection asset repair expenditure for the current *Regulatory Control Period* are set out in Table 68.

Aurora had no significant departures from the OTTER proposed expenditure during this *Regulatory Control Period*.

Table 68

Connection asset repair opex

Aurora's connection asset repair operating expenditure					
$2009–10	1/1/08 – 30/6/08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Actual	0.031	0.075	0.099	0.097	0.066
OTTER's proposed	0.033	0.066	0.066	0.077	0.077

12.4. 1 July 2012 – 30 June 2017

This section of Aurora's *Regulatory Proposal* will focus on the forecast operating expenditure for the forthcoming *Regulatory Control Period* (1 July 2012 – 30 June 2017).

Aurora has developed a detailed work program containing the operating and maintenance projects it has forecast will be required during the 2012-17 *Regulatory Control Period*. This work program includes estimated volumes and rates for each project, for each year of the *Regulatory Control Period*. These projects have been further classified to individual work and RIN categories and form the basis of Aurora's total operating expenditure forecasts for the 2012-17 *Regulatory Control Period*. Aurora's work program is appended as an attachment to this *Regulatory Proposal*.

Aurora has separated its operating expenditure proposals into three primary RIN categories and six sub-categories as detailed in Table 69.

Table 69

Opex RIN categories

RIN Category	RIN Sub-category
Operating costs	Network division management
	Non-network divisional management
	Operating costs – other
Maintenance costs	Routine maintenance
	Non-routine maintenance
Demand management	Demand management

Methodology to derive forecasts

The methodology for deriving the forecasts is the process that Aurora's engineers and management followed; and the policies and procedures that they had regard to, in developing the work programs. These methodologies and discussions relating to the forecasts are set out in the following sections by subcategory.

The methodology used by Aurora to develop the forecast projects for each work category is set out in Aurora's management plans. Within each subcategory Aurora also provides a list of the relevant work categories (where expenditure over the *Regulatory Control Period* exceeds $0.5 million), grouped by the associated management plans.

A forecast for each RIN sub-category is provided in the following sections.

12.4.1. Network division management

Background

Network division management activities relate to operational expenditure incurred by the Network division in planning, operating and monitoring of the distribution network.

The costs incurred in network division management are set out in detail below, and include the following six expenditure subcategories:

- network management;
- customer service;
- regulatory;
- NEM levy;
- electrical safety levy; and
- GSL payments.

The largest category cost within network division management is network management with a forecast requirement of $49.0 million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period*. This is a significant category of expenditure as it reflects the costs of managing the Network division and includes activities such as:

- fault and operations relating to the labour and associated costs with manning switchboards and fault operators;
- the network customer group that facilitates the customer dispute process, implements and improves customer service strategies that meet customer needs and expectations, and administers the customer charter;
- regulatory costs relating to the preparation of regulatory submissions, information requests, responses, setting tariffs, revenue and pricing submissions;
- commercial services relating to the provision of commercial awareness and advice, financial services and analysis across the distribution business, preparation of board reports, revenue recovery analysis, modelling, regulated and year end accounts, and policies and guidelines for the distribution business;
- asset management teams responsible for the management and planning of distribution assets;
- distribution IT systems relating to the management costs associated with strategic planning and IT architecture;
- the distribution executive team – one business development executive team providing shared service across the two divisions (strategic vision and leadership);
- the market services team which has expanded responsibilities with the advent of the NEM and retail competition;
- ensuring compliance with all the metering and connection work, including the meter technical specification, metering procedures, work instructions and the Service and Installation Rules; and
- maintenance contractor and consultancy costs to run the business.

Drivers

The primary cost drivers for network division management operational expenditure stem from the following:

- customer service requirements;
- reliability requirements;
- risk requirements;
- life cycle cost requirements;
- asset management policy compliance;
- capacity requirements;
- legislative and safety obligations; and
- environmental obligations.

Methodology to derive forecasts

The costs that underpin this expenditure are located in Aurora's budgeting and forecasting tool (BAF).

Network divisional management comprises the six expenditure categories discussed above.

Network Management

Expenditure for this category is forecast to be $46.8 million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period* and represents the costs of operating Aurora's Network division. This expenditure is forecast to increase slightly each year throughout the *Regulatory Control Period* and is split between:

- labour (52 percent of the total);
- contracts (13 percent of the total);
- materials (2 percent of the total); and
- other (33 percent of the total).

The forecast requirements allocated to *Standard Control Services* represent 86 percent of Aurora's total network management costs. Forecasts are derived using BAF.

Customer service

Expenditure for this category is forecast to be $7.2 million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period*. This expenditure is forecast to be constant throughout the *Regulatory Control Period* and is split between:

- labour (62 percent of the total);
- contracts (7 percent of the total);
- materials (<1 percent of the total); and
- other (30 percent of the total).

The forecast requirements allocated to *Standard Control Services* represent 84 percent of Aurora's total customer service costs. Forecasts are derived using BAF.

Regulatory

Expenditure for this category is forecast to be $3.7million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period*. This expenditure is forecast to reduce slightly throughout the *Regulatory Control Period* and is split between:

- labour (48 percent of the total);
- contractors (15 percent of the total); and
- other (37 percent of the total).

The forecast requirements allocated to *Standard Control Services* represent 84 percent of Aurora's total regulatory costs. Forecasts are derived using BAF.

Electrical safety levy

Expenditure for this category is forecast to be $13.1 million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period*. This expenditure is forecast to be constant throughout the *Regulatory Control Period*.

The forecast requirements allocated to *Standard Control Services* represents 84 percent of Aurora's total electrical safety levy costs. Forecasts are derived using BAF.

NEM levy

Expenditure for this category is forecast to be $1.5 million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period*. This expenditure is forecast to reduce slightly throughout the *Regulatory Control Period*.

The forecast requirements allocated to *Standard Control Services* represent 84 percent of Aurora's total NEM levy costs. Forecasts are derived using BAF.

GSL payments

Expenditure for this category is forecast to be $6.4 million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period*. This expenditure is forecast to reduce slightly throughout the *Regulatory Control Period* and is split between:

- labour (2 percent of the total); and
- other (98 percent of the total).

The forecast requirements allocated to *Standard Control Services* represents 100 percent of Aurora's total GSL payment costs, as other distribution services classifications do not attract this charge. Forecasts are derived using BAF.

Key assumptions

The key assumptions underlying Aurora's network division management operational expenditure works forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- the *TEC* will remain in force, and that any replacement will impose similar and not more prescriptive requirements upon Aurora in relation to asset replacement;
- Aurora's aged asset replacement model provides a prudent method of determining the asset replacement timetable for Aurora's assets;
- Aurora's method of assessing forecasts for condition based capital expenditure is a prudent method of determining the works required;
- the unit rates applied to expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

There are no instances where expenditure differs significantly from that of the current *Regulatory Control Period*.

Opex/Capex Interactions

There is a strong relationship between network divisional management and capital expenditure as network divisional management is vital from the time that capital expenditure is forecast to be required in network planning, to its costing phase, funding submissions to the regulator, construction phase and operation.

Forecasts

Aurora's forecasts (including escalations and overheads) for network division management operating expenditure for the forthcoming *Regulatory Control Period* are set out in Table 70.

Table 70

Network division management opex

Aurora's network division management operating expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	15.661	15.511	15.737	15.904	16.016

12.4.2. Non-network division management

Background

Non-network division management comprises three categories of operating expenditure being:

- system operations;
- corporate and shared services costs; and
- NEM and contestability related costs.

Operational activities for systems operations will remain consistent with historical practices. That is, these activities will continue to be performed to manage the real time operation of Aurora's distribution network and to ensure that the network is operated safely and within operating and load limits. It is a business imperative that the activities conducted by system operations deliver:

- no increase in customer service impacts (SAIDI/SAIFI) from current levels;
- no serious injury or loss of life arising from the operation of the network; and
- no prosecutions for breaches of legislative compliance.

Broadly corporate and shared costs relate to expenditure which is incurred across Aurora at an organisation-wide level. Aurora's ICAM allocates these costs to the Network Services and Network divisions. As the portion allocated to the Network Services division is already included in the work program values set out in other operating expenditure sections, this section discusses just the component of these costs that is allocated to the Network division.

NEM and contestability related costs comprise those activities undertaken within the Network division to ensure Aurora's distribution NEM operational capabilities and retail contestability requirements. These activities are typically performed by the members of the Market Services team but do however include those components from other teams that undertake 'market' activities and interactions.

Drivers

The primary cost drivers for the systems operations component of non-network division management operational expenditure stem from the following:

- reliability obligations; and
- customer services obligations.

The drivers of corporate and shared services costs are numerous and diverse and as a consequence are not set out in this section. These are however set out in detail in Aurora's Cost Allocation Method.

The drivers of NEM and contestability related costs are related to Aurora's operations in the NEM and the functions required to enable retail contestability activities.

Methodology to derive forecasts

For systems operations, the volumes and projects for all work categories that underpin this expenditure are located in Aurora's distribution work program. The individual categories within the work program can be referenced to specific sections of Aurora's 2011 management plans, and this section sets out the relevant plan for each work category listed. The methodology for deriving the forecasts is the process that Aurora's engineers and management followed, and the policies and procedures that they had regard to, in developing the work program. These methodologies and discussion relating to the forecasts is set out below by subcategory.

For corporate and shared services costs, the volumes and projects for the activities that underpin this expenditure are forecast by Aurora's corporate team. These forecasts are built up with regard to both corporate wide strategies and parameters; and forecasts and planning considerations by each division and subsidiary within Aurora. The costs are allocated to each division and subsidiary using Aurora's ICAM on the basis of the most appropriate driver.

For NEM and contestability related costs, the volumes and projects for the individual categories that underpin this expenditure are located in BAF.

System operations

The two work categories associated with systems operations are:

- system reconfigurations; and
- system status checks.

System reconfigurations

This expenditure covers the operational activities associated with the network system management for load, safety, voltage and system stability and constraints purposes. This is considered business as usual and a requirement of Aurora's licence conditions in that it must comply with the *ESI Act*, *TEC* and guidelines and the *Rules*.

A total of $0.7 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category spread over 5 line items across a single subcategory; system reconfigurations. This expenditure profile decreases over the *Regulatory Control Period*.

System status checks

This expenditure covers the operational activities associated with the checking/recording of the operational status and equipment verification by field personnel and includes but is not limited to checking of system loadings and voltages, substation labelling and system configuration.

A total of $0.1 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category spread over 5 line items across a single subcategory; system operations. This expenditure profile decreases over the *Regulatory Control Period*.

The methodology used by Aurora to develop the forecast projects is set out in the Management Plan 2011 – System Operations.

Corporate and shared services costs

A total of $47.8 million ($2009-10 excluding escalations and overheads) is forecast to be required for corporate and shared services expenditure. The associated profile is reasonably static throughout the *Regulatory Control Period*. This expenditure comprises five high level categories with the largest category, forecast at $37.2 million, relating to commercial services. As set out above, this expenditure is forecast by the corporate finance team on the basis of organisation-wide and divisional planning parameters.

This expenditure is forecast to be required for five overall subcategories of expenditure, being:

- office of the CEO;
- audit and risk;
- people and culture;
- strategy and corporate affairs; and
- commercial services.

Office of the CEO

Activities within this subcategory amount to a total of $3.1 million over the *Regulatory Control Period*. This profile of expenditure is static throughout the *Regulatory Control Period*.

Audit and risk

Activities within this subcategory amount to a total of $0.8 million over the *Regulatory Control Period*. This profile of expenditure is static throughout the *Regulatory Control Period*.

People and culture

Activities within this subcategory amount to a total of $2.6 million over the *Regulatory Control Period*. This profile of expenditure decreases minimally throughout the *Regulatory Control Period*.

Strategy and corporate affairs

Activities within this subcategory amount to a total of $4.4 million over the *Regulatory Control Period*. This profile of expenditure decreases minimally throughout the *Regulatory Control Period*.

Commercial services

Activities within this subcategory amount to a total of $36.9 million over the *Regulatory Control Period*. This profile of expenditure is static throughout the *Regulatory Control Period*.

NEM and contestability related

Expenditure for this category is forecast to be $7.3 million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period* and represents the costs associated with NEM operations and contestability related functions within Aurora's Network division. This expenditure is forecast to increase slightly each year throughout the *Regulatory Control Period*.

Key assumptions

The key assumptions underlying Aurora's non-network division management operational expenditure works forecast are that:

- Aurora's overall organisation-wide strategies and plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- Aurora's ICAM provides an appropriate method for apportioning corporate and shared costs to the Network division;
- Aurora's method of assessing forecasts for NEM and contestability related operating expenditure is a prudent method of determining the costs involved;
- Aurora's method of assessing forecasts for system operations operating expenditure is a prudent method of determining the works required;
- the unit rates applied to system operations operating expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to system operations operating expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to system operations operating expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

There are no instances where expenditure differs significantly from that of the current *Regulatory Control Period*.

Opex/Capex Interactions

There is a strong relationship between system operations operating expenditure and the non-demand related capital expenditure category which relates to capital expenditure on assets in accordance with the network vision, asset management plan and thread management plans. This is because expenditure on non-network divisional management ensures assets are operated within manufacturers' specifications and guidelines which will prolong their life and defers the need for new assets.

There is no relationship between corporate and shared services operating expenditure and capital expenditure.

As Aurora will have implemented its NEM and contestability related capital projects prior to the commencement of the forthcoming *Regulatory Control Period,* there is no relationship between this expenditure and capital expenditure.

Forecasts

Aurora's forecasts (including escalations and overheads) for non-network division management operating expenditure for the forthcoming *Regulatory Control Period* are set out in Table 71.

Table 71

Non-network division management opex

Aurora's non-network division management operating expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	11.489	11.400	11.381	11.280	11.250

12.4.3. Other operating costs

Background

The other operating costs operating expenditure covers all other operating expenditure not specifically covered in another category and is consequently diverse in its nature. This expenditure category does not include subcategories.

Projects undertaken under other operating costs relate to the following activities:

- service provider charges (services);
- licences and maintenance agreements;
- system spares management;
- distribution SCADA operating costs, modem, communications, etc;
- the installation of power quality meters – communications costs;
- consumables and minor repairs; and
- data services.

Drivers

The drivers for this category relate to:

- customer service requirements; and
- reliability requirements.

Methodology to derive forecasts

As noted previously, the volumes and projects for all work categories that underpin this expenditure are located in Aurora's work program. The individual categories within the work program can be referenced to specific sections of Aurora's 2011 management plans and strategy documents, and this section sets out the relevant plan or strategy for each work category listed (where expenditure over the *Regulatory Control Period* exceeds $0.5 million).

Other operating costs

A total of $22.9 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category over the *Regulatory Control Period*. This expenditure is forecast to be required for 45 line items of varying types across one subcategory; operating costs other. This expenditure profile is constant throughout the *Regulatory Control Period*.

The largest work category expenditure relates to software and hardware service provider charges with an associated expenditure of $19.8 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

The following is a list of the relevant work categories, and the associated management plans and strategy documents:

Management Plan 2011 – Protection and Control:

- operating modem costs for reclosers.

Distribution Network IT Strategy[1]:

- software and hardware consumables; and
- software and hardware service provider charges.

1 Aurora Energy Distribution Network ISG Strategy 2012-2017, Final Version 1, 15 March 2011.

The anticipated works are based on implementing the initiatives in the Network IT Strategy[2].

Aurora's implementation of this strategy is discussed in greater detail in section 11.4.5 of this *Regulatory Proposal*.

Key assumptions

The key assumptions underlying Aurora's other operating costs operational expenditure works forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- the TEC will remain in force, and that any replacement will impose similar and not more prescriptive requirements upon Aurora in relation to any other operating costs;
- Aurora's method of assessing forecasts for other operating costs expenditure is a prudent method of determining the works required;
- the unit rates applied to other operating costs expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to other operating costs expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to other operating costs expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

The implementation of the Network IT strategy has resulted in a significant increase in operating expenditure from that of the current *Regulatory Control Period*.

Opex/Capex Interactions

There is a strong relationship between other operating costs operational expenditure and capital expenditure. This is because other operating costs covers hardware service provider charges, maintenance agreements and minor repairs which directly and indirectly prolong the life of existing assets and defers the need for new assets.

Forecasts

Aurora's forecasts (including escalations and overheads) for operating costs – other operating expenditure for the forthcoming *Regulatory Control Period* are set out in Table 72.

Table 72

Other operating costs opex

Aurora's other operating costs operating expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	4.531	4.559	4.586	4.612	4.639

2 Ibid.

12.4.4. Routine maintenance

Background

Routine maintenance comprises scheduled inspection and maintenance activities. It is generally carried out at predetermined intervals, or in accordance with prescribed criteria, in order to minimise the probability of network failure; minimise total life cycle costs; meet required operating conditions and performance standards; and keep staff and the public safe. Routine maintenance prolongs the life of existing assets, reduces the probability of failure or the degradation of the performance of an asset and therefore the need for non-routine maintenance.

Work that is identified from the routine maintenance program can be undertaken as either asset replacement capital expenditure or non-routine maintenance, so that operating expenditure due to an unexpected event or failure is minimised and total maintenance expenditure is optimised.

As discussed in Aurora's asset management plan, the maintenance program is driven by the following principles:

- reliable operation to meet the needs of the customer;
- ensure existing assets are safe and compliant with all applicable legislation;
- reach the least cost trade-off between different modes of maintenance (repair, refurbishment, replacement);
- reach the optimal reactive-preventative maintenance ratio for the asset base;
- condition monitoring and predictive analysis forms the foundation of asset maintenance; and
- the optimal mode of managing assets varies between asset classes.

It is noted that time-based cycles of routine servicing are undertaken where condition-based monitoring is not practical or possible. The application of these techniques is based on manufacturer's recommendations, industry practice and Aurora's own experience.

Expenditure on routine maintenance is relatively stable each year and is forecast at $60.3 million ($2009-10 excluding escalations and overheads) over the *Regulatory Control Period*.

Routine maintenance operational expenditure covers two categories, being:

- network asset maintenance; and
- non-network asset maintenance,

which include seven subcategories.

Drivers

The drivers for this category are:

- customer service requirements;
- reliability requirements;
- legislative and safety obligations;
- capacity requirements;
- risk mitigation; and
- life cycle cost requirements.

Methodology to derive forecasts

As noted previously, the volumes and projects for all work categories that underpin this expenditure are located in Aurora's work program. The individual categories within the work program can be referenced to specific sections of Aurora's 2011 management plans, and this section sets out the relevant management plan for each work category.

Network asset maintenance

A total of $23.0 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category over the *Regulatory Control Period*. This expenditure is forecast to be required for 476 line items of varying types across five overall subcategories, being:

- ground mounted substations;
- overhead network and structures;
- underground network;
- zone substations; and
- routine maintenance other.

Ground mounted substations

There are 140 line items across the *Regulatory Control Period* with a total value of $2.8 million. This expenditure profile decreases over the *Regulatory Control Period*. The largest work category expenditure is ground mounted substation inspection and load monitoring with an associated expenditure of $2.1 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Ground Mounted Substations:

- ground mounted substation inspection and load monitoring.

Management Plan 2011 – High Voltage Regulators:

- regulators (ground mounted) routine maintenance.

The anticipated works are based on maintaining consistency with Aurora's historical expenditure.

Overhead network and structures

There are 120 line items across the *Regulatory Control Period* with a total value of $12.7 million. This expenditure profile is constant throughout the *Regulatory Control Period*. The largest work category expenditure is overhead structures inspection and monitoring with an associated expenditure of $10.5 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Overhead System and Structures:

- overhead structures inspection and monitoring;
- OH system thermal inspection; and
- OH transformers load and voltage monitoring.

The anticipated works are based on Aurora's historical expenditure.

Underground network

There are 50 line items across the *Regulatory Control Period* with a total value of $0.5 million. The expenditure profile reduces slightly each year over the *Regulatory Control Period*. The largest work category expenditure is oil-filled cable inspection and monitoring with an associated expenditure of $0.1 million.

The methodology used by Aurora to develop the forecast projects is set out in Aurora's management plans and the expenditure of each of the four work categories which comprise this subcategory are not forecast to exceed $0.5 million over the *Regulatory Control Period*.

The anticipated works are based on maintaining consistency with Aurora's historical expenditure.

Zone substations

There are 152 line items across the *Regulatory Control Period* with a total value of $5.0 million. The expenditure profile reduces slightly over the *Regulatory Control Period*. The largest work category expenditure is ground mounted substation routine maintenance with an associated expenditure of $3.2 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Ground Mounted Substations:

- ground mounted substation routine maintenance.

Management Plan 2011 – Zone Substations:

- zone substation routine maintenance.

The anticipated works are based on Aurora's current practices, but with additional expenditure.

Routine maintenance other

There are 14 line items across the *Regulatory Control Period* with a total value of $2.0 million. The expenditure profile reduces slightly each year over the *Regulatory Control Period*. The largest work category expenditure is oil management with an associated expenditure of $1.9 million.

The methodology used by Aurora to develop the forecast projects is set out in Aurora's management plans and the expenditure on each of the two work categories which comprise this subcategory is not forecast to exceed $0.5 million over the *Regulatory Control Period*.

The anticipated works are based on Aurora's current asset management practices without any significant changes.

Non-network asset maintenance

A total of $37.3 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category over the *Regulatory Control Period*. This expenditure is forecast to be required for 20 line items of varying types across two overall subcategories, being:

- connection asset repair; and
- vegetation management.

Connection asset repair

There are 10 line items across the *Regulatory Control Period* with a total value of $1.2 million. This expenditure profile decreases over the *Regulatory Control Period*. The largest work category expenditure is meter ancillary equipment inspection with an associated expenditure of $1.0 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Connection Assets:

- meter ancillary equipment inspection; and
- overhead conductor condition inspection.

The anticipated works are based on Aurora's historical service related outage information. For meter ancillary equipment inspection, compliance with the requirements of schedule 7.3 of the *Rules* and clause 9.18.2 of the *TEC* requires that all metering CTs and VTs must be tested every 10 years. As a result, Aurora has a program in place to test 10 percent of installed stock, or 410 metering transformers, annually.

Vegetation management

There are 10 line items across the *Regulatory Control Period* with a total value of $36.0 million. This subcategory comprises a single work category; vegetation management. The highest annual cost for this category is $7.5 million in 2012-13. This expenditure profile reduces throughout the *Regulatory Control Period*.

The methodology used by Aurora to develop the forecast projects is set out in Aurora's Management Plan 2011 – Vegetation Management.

The anticipated works are based on data from two key sources:

- the field recorded scoped work from Aurora's vegetation management information technology system (known as VEGEMITe); and
- historical work volume and costing information from contractor timesheets.

From these a unit pricing approach was applied to predict future expenditure requirements.

Key assumptions

The key assumptions underlying Aurora's routine maintenance operational expenditure works forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- the *TEC* will remain in force, and that any replacement will impose similar and not more prescriptive requirements upon Aurora in relation to Routine Maintenance;
- Aurora's method of assessing forecasts for routine maintenance is a prudent method of determining the works required;
- the unit rates applied to routine maintenance expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to routine maintenance expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to routine maintenance expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

There are no instances where expenditure differs significantly from that of the current *Regulatory Control Period*. Aurora has however forecast increases in expenditure within the overhead network and structures subcategory for asset repairs associated with defects in the overhead network; and within the ground mounted substations and the zone substations subcategories for compliance obligations associated with substations.

Opex/capex interactions

There is a strong relationship between routine maintenance and:

- the non-demand related capital expenditure category which relates to capital expenditure on assets in accordance with the network vision, asset management plan and thread management plans. This is because expenditure on routine maintenance prolongs the life of existing assets and defers the need for new assets.
- the non-routine maintenance program because, if routine maintenance programs do not identify assets for replacement which should be identified as such, then issues may occur which require unplanned maintenance activities.

Forecasts

Aurora's forecasts (including escalations and overheads) for routine maintenance operating expenditure for the forthcoming *Regulatory Control Period* are set out in Table 73.

Table 73

Routine maintenance opex

Aurora's routine maintenance operating expenditure					
$2009–10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	16.626	16.261	16.034	15.726	15.211

12.4.5. Non-routine maintenance

Background

Non-routine maintenance expenditure refers to operating expenditure on repair work identified and assessed as defects to prevent dangerous occurrences such as unplanned outages or hazardous electrical events. This category of work is carried out on a regular basis and involves both:

- repair and replacement work that is carried out after defects are identified through routine maintenance, in order to fix the defect and prevent an outage or a dangerous electrical event occurring; and
- unplanned repair, replacement or restoration work undertaken as a matter of urgency after an unexpected event or failure to ensure that the system is at least operating at the minimum standard.

One of the key drivers for non-routine maintenance is Aurora's condition assessment and inspection program. Inspection processes generating high volumes of data utilise electronic field capture systems to minimise data processing.

Although expenditure in this category is emergent, Aurora must make provision for non-routine maintenance activities in deriving its operating expenditure forecasts. Aurora's maintenance program is driven by the need to:

- ensure reliable operation to meet the needs of the customer;
- ensure existing assets are safe and compliant with all applicable legislation;
- reach the least cost trade-off between different modes of maintenance (repair, refurbishment, replacement); and
- reach the optimal reactive-preventative maintenance ratio for the asset base.

Aurora notes that an identified defect can be repaired and expensed as non-routine maintenance, or alternatively capitalised as non-demand related expenditure, with the treatment of the defect being governed by Aurora's capitalisation policies.

Expenditure on non-routine maintenance declines throughout the *Regulatory Control Period* and is forecast at $76.2 million excluding overheads.

Non-routine maintenance operational expenditure covers two categories, being:

- network asset maintenance; and
- non-network asset maintenance.

which include nine subcategories including overhead network and structures, emergency and unscheduled power system and vegetation management.

Drivers

The drivers for this category are:

- customer service requirements;
- reliability requirements;
- asset management policy compliance;
- risk requirements; and
- life cycle cost requirements.

Methodology to derive forecasts

As noted previously, the volumes and projects for all work categories that underpin this expenditure are located in Aurora's work program. The individual categories within the work program can be referenced to specific sections of Aurora's 2011 management plans, and this section sets out the relevant management plan for each work category listed.

Network asset maintenance

A total of $16.4 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category over the *Regulatory Control Period*. This expenditure is forecast to be required for 145 line items of varying types across six overall subcategories, being:

- decommission assets;
- ground mounted substations;
- non-routine maintenance other;
- overhead network and structures;
- underground systems; and
- zone substations.

Decommission assets

There are 10 line items across the *Regulatory Control Period* with a total value of $1.7 million. This expenditure profile decreases throughout the *Regulatory Control Period*. The largest work category expenditure relates to decommission assets with an associated expenditure of $1.3 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Connection Assets:

- decommission metering assets.

Management Plan 2011 – Overhead System and Structures:

- decommission assets.

The anticipated works are based on maintaining consistency with Aurora's historical expenditure.

Ground mounted substations

There are 60 line items across the *Regulatory Control Period* with a total value of $1.1 million. This expenditure profile decreases throughout the *Regulatory Control Period*. The largest work category expenditure relates to ground mounted substations asset repair with an associated expenditure of $0.9 million.

The methodology used by Aurora to develop the forecast projects is set out in the Management Plan 2011 – Ground Mounted Substations.

The anticipated works are based on Aurora's historical expenditure pattern.

Non-routine maintenance other

There are 10 line items across the *Regulatory Control Period* with a total value of $1.9 million. The expenditure profile reduces each year throughout the *Regulatory Control Period*. The largest work category expenditure relates to power quality monitoring and investigations with an associated expenditure of $1.8 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Overhead system and structures:

- oil management.

Management Plan 2011 – Power Quality:

- power quality monitoring and investigations.

The anticipated works are based on maintaining consistency with Aurora's historical expenditure.

Overhead network and structures

There are 40 line items across the *Regulatory Control Period* with a total value of $10.0 million. The expenditure profile reduces slightly throughout the *Regulatory Control Period*. The largest work category expenditure relates to overhead system asset repair with an associated expenditure of $4.1 million.

The methodology used to develop the forecast projects is set out in Aurora's management plans. The following list of the relevant work categories is grouped by the associated management plan.

Management Plan 2011 – Overhead System and Structures:

- asset repair – fire mitigation;
- overhead structures maintenance pole straightening;
- overhead switchgear asset repair;
- overhead system asset repair;
- overhead system low conductor clearance.

Management Plan 2011 – Reliability:

- targeted reliability improvement program maintenance costs.

The anticipated works are based on Aurora's current practices, but with some additional expenditure.

Underground systems

There are 15 line items across the *Regulatory Control Period* with a total value of $1.5 million. The expenditure profile reduces each year throughout the *Regulatory Control Period*. The largest work category expenditure relates to underground system asset repair with an associated expenditure of $1.3 million.

The methodology used by Aurora to develop the forecast projects is set out in the Management Plan 2011 – Underground System.

The anticipated works are based on Aurora's current asset management practices without any significant changes.

Zone substations

There are 10 line items across the *Regulatory Control Period* with a total value of $0.3 million. The only work category expenditure is zone substation asset repair. The expenditure profile slightly reduces each year throughout the *Regulatory Control Period*.

The methodology used by Aurora to develop the forecast projects is set out in Aurora's management plans. The expenditure for the zone substation asset repair category is not forecast to exceed $0.5 million over the *Regulatory Control Period*.

The anticipated works are based on Aurora's current practices.

Non-network asset maintenance

A total of $60.0 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category. This expenditure is forecast to be required for 30 line items of varying types across three overall subcategories, being:

- connection asset repair;
- emergency and unscheduled power system;
- electrical safety and installation inspection; and
- vegetation management.

Connection asset repair

There are five line items across the *Regulatory Control Period* with a total value of $0.2 million. The only work category expenditure is meter ancillary equipment repair. The expenditure profile slightly reduces each year throughout the *Regulatory Control Period*.

The methodology used by Aurora to develop the forecast projects is set out in Aurora's management plans. The expenditure for the meter ancillary equipment repair category is not forecast to exceed $0.5 million over the *Regulatory Control Period*.

The anticipated works are based on Aurora's current practices.

Emergency and unscheduled power system

There are 10 line items across the *Regulatory Control Period* with a total value of $53.4 million. This expenditure profile reduces considerably throughout the *Regulatory Control Period*. This subcategory comprises a single work category; emergency and unscheduled power system response and repair; and the highest annual cost for this category is $11.1 million in 2012-13.

The methodology used by Aurora to develop the forecast projects is set out in Aurora's Management Plan 2011 – Systems Operations.

The anticipated works are based on Aurora's current practices.

Electrical safety and installation inspection

There are 5 line items across the *Regulatory Control Period* with a total value of $1.5 million. This expenditure profile is uniform throughout the *Regulatory Control Period*. This subcategory comprises a single work category; electrical safety and installation inspection with forecast expenditure of $0.3 million for each year of the *Regulatory Control Period*.

The methodology used by Aurora to develop the forecast projects is set out in Aurora's Management Plan 2011 – Overhead System and Structures.

The anticipated works are based on Aurora's current practices.

Vegetation management

There are 10 line items across the *Regulatory Control Period* with a total value of $4.6 million. The profile of expenditure is uniform throughout the *Regulatory Control Period*. This subcategory comprises a single work category; access track clearing with forecast expenditure of $0.9 million for each year of the *Regulatory Control Period*.

The methodology used by Aurora to develop the forecast projects and the plan for access track clearing is set out in Aurora's Management Plan 2011 – Overhead System and Structures.

The proposed expenditure has increased compared to historical expenditure due to the increased number of access tracks requiring maintenance when compared to the previous *Regulatory Control Period*.

Key assumptions

The key assumptions underlying Aurora's non-routine maintenance operational expenditure works forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- the *TEC* will remain in force, and that any replacement will impose similar and not more prescriptive requirements upon Aurora in relation to non-routine maintenance;
- the frequency and magnitude of network impacts requiring non-routine maintenance experienced in the current *Regulatory Control Period* is a proxy for the level that will be experienced in the forthcoming *Regulatory Control Period*;
- Aurora's method of assessing forecasts for non-routine maintenance is a prudent method of determining the works required;
- the unit rates applied to non-routine maintenance expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to non-routine maintenance expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to non-routine maintenance expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

There are no instances where expenditure differs significantly from that of the current *Regulatory Control Period*. Aurora has however forecast increases in expenditure within the overhead network and structures and ground mounted substations subcategory for asset defect repairs.

Opex/capex interactions

There is a strong relationship between non-routine maintenance and:

- the non-demand related capital expenditure which includes capital expenditure on infrastructure components that have failed or are imminently about to fail. This is because one of the objectives of non-demand related programs is to identify where specific activity is required to mitigate network failure as well as to reduce costs and comply with required standards. However it is important to note that non-routine maintenance activities are emergent works and can be driven by unpredictable and unavoidable factors such as adverse weather conditions. As such increased non-demand related capital expenditure activities provide only limited benefits to reducing forced maintenance operating expenditure; and
- the routine maintenance operating expenditure which essentially identifies the assets that require replacement for condition-based risk reasons. There is a minor relationship between these categories as Aurora, at times, undertakes non-routine maintenance to rectify network failure that may not have occurred if it had been identified and rectified earlier. A decision is then made as to whether to rectify the issue as operating expenditure, or to capitalise the expenditure under an asset replacement capital expenditure category. Any reduction in routine maintenance program will result the reduced identification of defects, and will therefore increase outages and dangerous electrical events and a need for increased non-routine maintenance operating expenditure.

Forecasts

Aurora's forecasts (including escalations and overheads) for non-routine maintenance operating expenditure for the forthcoming *Regulatory Control Period* are set out in Table 74.

Table 74

Non-routine maintenance opex

Aurora's non-routine maintenance operating expenditure					
$2009–10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	21.439	20.501	19.860	19.030	17.547

12.4.6. Demand management

Background

Demand management expenditure refers to operating expenditure on activities that are designed to minimise the impact of peak demand on the distribution network and to defer capital expenditure resulting from increases in overall system demand. This category of work is in excess of that undertaken as part of the AER's demand management incentive scheme.

One of the key drivers for demand management expenditure is the need to find suitable alternatives to continued investment in the distribution network as demand grows. This can be achieved by means of alternative non-network solutions or incentives that provide customers with the means to minimise demand increases.

Drivers

The drivers for this category are:

- customer service requirements;
- reliability requirements;
- risk requirements; and
- life cycle cost requirements.

Methodology to derive forecasts

As noted previously, the volumes and projects for all work categories that underpin this expenditure are located in Aurora's work program. The individual categories within the work program can be referenced to specific sections of Aurora's 2011 management plans, and this section sets out the relevant management plan for each work category.

Demand management

- A total of $3.3 million ($2009-10 excluding escalations and overheads) is forecast to be required within this category over the *Regulatory Control Period*. This expenditure is forecast to be required for 43 line items of varying types across one subcategory; operating costs other. This expenditure profile varies throughout the *Regulatory Control Period*.
- The largest work category expenditure relates to capex deferrals with an associated expenditure of $1.2 million.
- The methodology used by Aurora to develop the forecast projects is set out for each work category in Aurora's Management Plan 2011 – Demand Management.

Key assumptions

The key assumptions underlying Aurora's demand management operational expenditure works forecast are that:

- Aurora's overall network strategy will remain unchanged for the *Regulatory Control Period*;
- Aurora's management plans will remain unchanged for the *Regulatory Control Period*;
- Aurora's work practices will remain unchanged for the *Regulatory Control Period*;
- the *TEC* will remain in force, and that any replacement will impose similar and not more prescriptive requirements upon Aurora in relation to non-routine maintenance;
- Aurora's method of assessing forecasts for demand management initiatives is a prudent method of determining the works required;
- the unit rates applied to demand management expenditure will be the same as the out-turn costs faced by Aurora;
- the overheads applied to demand management expenditure will be the same as the out-turn costs faced by Aurora; and
- the escalation applied to demand management expenditure will be the same as the out-turn costs faced by Aurora.

Expenditure variations

This is a new category of expenditure and is not included in the current *Regulatory Control Period*.

Opex/capex interactions

There is a strong relationship between demand management and demand related capital expenditure. This is because one of the objectives of demand management programs is to identify specific activities that will lead to the deferral or necessity for demand related network investment. Successful implementation of demand management schemes and incentives will lessen the need for demand related capital expenditure.

Forecasts

Aurora's forecasts (including escalations and overheads) for demand management operating expenditure for the forthcoming *Regulatory Control Period* are set out in Table 75.

Table 75

Demand management opex

Aurora's demand management operating expenditure					
$2009–10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast	0.891	0.411	0.501	0.746	0.786

12.5. Total operating expenditure

Aurora's forecasts (including escalations and overheads) for operating expenditure for the forthcoming *Regulatory Control Period* are set out in Table 76.

Table 76

Total opex

Aurora's total operating expenditure					
$2009–10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Operating costs					
Network management	15.661	15.511	15.737	15.904	16.016
Non-network management	11.489	11.400	11.381	11.280	11.250
Operating costs – other	4.531	4.559	4.586	4.612	4.639
Maintenance costs					
Routine maintenance	16.626	16.261	16.034	15.726	15.211
Non-routine maintenance	21.439	20.501	19.860	19.030	17.547
Demand management					
Demand management	0.891	0.411	0.501	0.746	0.786
Total	**70.637**	**68.643**	**68.099**	**67.298**	**65.449**

Aurora's actual and forecast for *Standard Control Services* operating expenditure for the current and forthcoming *Regulatory Control Periods* is set out in Table 77.

Table 77

Operating expenditure

Aurora's operating expenditure	Actual			Forecast						
$2009–10	2007-08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Total expenditure	58.854	68.294	80.215	78.924	74.581	70.637	68.643	68.099	67.298	65.449
OTTER proposed	59.679	71.309	74.118	76.730	76.566					

13. Capex – Opex Trade-Offs

13. Capex – opex trade-offs

13.1. Background

Clauses 6.5.6(e)(7) and 6.5.7(e)(7) of the *Rules* respectively require that the AER, when considering Aurora's capital and operating expenditure proposals, have regard for whether Aurora has considered substitution possibilities between operating and capital expenditure.

Further, clause S6.1.3(1) of the *Rules* requires Aurora's building block proposal to identify and explain any significant interactions between its operating and capital expenditure forecasts.

13.2. Interactions between capital and operating expenditure

The following sections discuss the relationships that exist between Aurora's capital and operating expenditure programs. Aurora's management plans include details of the interactions that exist between expenditure programs and how those interactions influence the decision making processes undertaken by Aurora's managers and engineers when undertaking these programs.

13.2.1. Capitalised overheads

There is no direct relationship between Aurora's capitalised overheads capital expenditure and operating programs.

Aurora's capitalised overheads relate to the capital portion of the Network Services division's direct overheads that are allocated to all Aurora's other capital programs. Interactions with operating programs are therefore discussed in these sections.

13.2.2. Demand related capital expenditure

There are two categories of expenditure within the demand related capital expenditure programs that have interactions with Aurora's operating expenditure programs. These categories are: customer initiated and reinforcements capital expenditure. These categories are discussed below.

Customer initiated capital expenditure

Aurora's customer initiated capital expenditure has one main interaction with operating expenditure programs. With additional new customer connection capital expenditure comes a corresponding increase in maintenance activities, as these new assets eventually require scheduled maintenance in accordance with the network vision, asset management plan and thread management plans. There is therefore a direct relationship between growth in the network through customer initiated capital expenditure and maintenance operating expenditure.

The impacts that additional customer connections have on Aurora's maintenance regimes are dealt with in the management plans associated with Aurora's operating expenditure categories.

Reinforcements capital expenditure

Aurora's reinforcements capital expenditure has two main interactions with operating expenditure programs:

- without reinforcements capital expenditure on augmentation, there is a greater likelihood of Aurora's network failing to meet the network planning criteria set out in the management plans appended as an attachment to this *Regulatory Proposal*. Asset failure can have the consequential impact of outages to Aurora's customers, requiring non-routine maintenance operating expenditure; and
- as with all capital expenditure, additional demand driven capital expenditure brings with it a corresponding increase in maintenance activities, as these new assets eventually require scheduled maintenance in accordance with the network vision, asset management plan and thread management plans. There is therefore a direct relationship between growth in the network through reinforcements capital expenditure and maintenance operating expenditure.

The decisions made within Aurora's engineering management on whether a need for augmentation can be met via operating expenditure or alternative capital augmentation projects – for example through non-network alternatives – are dealt with in the management plans associated with this expenditure category.

13.2.3. Non-demand related capital expenditure

There is a strong interaction between the non-demand related capital expenditure forecast and:

- routine maintenance operating expenditure, which identifies assets which require replacement for condition-based risk reasons. There is a positive relationship between these two categories, in that the larger the scope and breadth of the inspection program, the larger the number of condition-based replacements that will be identified. In addition, the greater the number of assets replaced, the smaller the number of assets in the future that will be identified during the routine maintenance program as requiring replacement; and
- emergency and unscheduled power system operating expenditure, as replacing assets reduces the risk of forced maintenance from defects. This in turn reduces the risks from in-service asset failures and from dangerous electrical events.

Further, there are positive relationships between routine and non-routine maintenance programs and the life of assets installed in the network. Through regular maintenance and corrective action taken when issues are identified, Aurora ensures that assets can operate for as long as possible within the network and therefore reduce the need for condition-based asset replacement expenditure.

The key interactions between the non-demand related capital expenditure forecasts and the operating expenditure programs include:

- ensuring reliability compliance across the network reduces customer outages and therefore reduces call-outs which impact on operating expenditure;
- improving power quality reduces call-outs to customer premises and therefore reduces expenditure; and
- ensuring preventive and corrective maintenance programs underpin the forecast reliability performance of Aurora's distribution system.

Aurora's operating and capital programs have been structured to operate in combination to ensure that Aurora can meet its service standard expectations and ensure the performance of poor performance parts of the network achieves the required *TEC* standard.

The decisions made within Aurora's engineering management on whether a need for asset replacement can be met via operating and maintenance projects – for example through corrective maintenance– are dealt with in the management plans associated with this expenditure category.

13.2.4. Regulatory obligations or requirements

Aurora's regulatory obligations or requirements capital expenditure has interactions with both capital and operating expenditure programs. With new regulatory requirements there are typically resultant changes to Aurora's practices for both capital and operating expenditure and a corresponding increase in maintenance and operating activities.

The impacts that additional regulatory obligations or requirements have on Aurora's maintenance and operating programs are dealt with in the management plans associated with Aurora's operating expenditure categories.

13.2.5. Non-network capital expenditure

A general interaction exists between non-network capital expenditure and Aurora's operating costs. The greater non-network capital expenditure, the more resourcing is needed to maintain these new assets such as IT, fleet and property.

Increased non-network capital expenditure can also decrease the resourcing needed to maintain these assets. As new and efficient assets replace those assets that are toward the end of their useful lives Aurora's maintenance and operating costs will typically reduce.

The decisions made within Aurora's management on whether a need for asset replacement will deliver the best overall cost solution for Aurora are dealt with in the management plans associated with this expenditure category.

13.2.6. SCADA and network control

There is a strong relationship between SCADA and network control capital expenditure and Aurora's operational expenditure programs. New SCADA systems allow for the efficient identification, diagnosis, planning and rectification of faults and the real time operation of the components that are included within the distribution network.

The ability to work remotely from a fault or a switch allows Aurora to minimise operational expenditure in areas including labour costs, spare parts and inventory holdings.

The decisions made within Aurora's engineering management on the need for SCADA and network control capital expenditure and its interactions with operating programs is dealt with in the management plans associated with the SCADA and network control capital expenditure category and Aurora's operational expenditure management plans.

14. Non-Network Alternatives

14. Non-network alternatives

Aurora has an obligation to implement efficient non-network alternatives or to manage the expected demand for *Standard Control Services* in line with its demand management strategy.

Non-network alternatives in preference to supply side augmentations are effective strategies to manage the demand on the network and include the following options:

- embracing demand side management, i.e. managing the customer's peak demand on the system;
- utilising embedded generation in the network (both on the customer side and on the network side including storage solutions);
- supporting energy efficiency initiatives to reduce demand;
- installing automated load transfer systems to optimise the configuration of the network during peak demand;
- adopting system optimisation methodologies, such as dynamic ratings based on live thermal measurements; and
- Power factor correction.

14.1. Background and Rules requirements

Clauses 6.5.6(e)(10) and 6.5.7(e)(10) of the *Rules* require, in relation to operating and capital expenditure respectively, that the AER have regard to whether Aurora has considered and made provision for non-network alternatives.

Clause 5.6.2 (f) of the *Rules* obligates Aurora to investigate and consult on demand side and generation options when investigating options to address identified limitations in the distribution network. Promotion of economic efficient investment in the electricity network through the economic assessment of both network and non-network options to address network limitations is further supported by clause 5.6.2(g) of the *Rules*.

Clause 5.6.5A of the *Rules* states that the purpose of the regulatory test is to identify new network investments or non-network alternative options that:

- maximise the net economic benefit to all those who produce, consume and transport electricity in the market; or
- in the event the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 of the *Rules* or in applicable regulatory instruments, minimise the present value of the costs of meeting those requirements.

Aurora's planning process includes these requirements and the application of the regulatory test.

14.2. Strategy

Aurora will manage expected demand on the network by implementing cost effective non-network initiatives that are balanced against efficient supply side/network solutions.

14.3. Process for identifying non-network and demand management alternatives

Non-network initiatives and the associated identification process fall into two distinct streams:

(1) Identification of broad based non-network initiatives through:

- (i) the review of system load characteristics to identify opportunities to modify, reduce or transfer the load at time of substation/system peak demand;
- (ii) studies of the identified opportunities to determine realistic, cost effective broad based options that will provide system wide reductions in peak demand; and
- (iii) options prioritised based on potential effectiveness for inclusion in the annual work program.

(2) Identification of non-network initiatives to address specific network limitations through:

- (i) the determination/identification of network limitations through the analysis of the load forecast and system capability;
- (ii) the identification of cost effective network augmentation options;
- (iii) the review of the network limitation and identified network augmentation options with a focus on identification of possible non-network options (e.g. peak shaving generation, demand management, etc.);
- (iv) development of non-network options to directly remove the limitation by containing peak demand below system capability or defer the need for the network augmentation solution by limiting the growth of peak demand; and
- (v) cost effective non-network solutions that are included in the annual work program and the network solution is either removed or deferred.

14.4. Current Regulatory Control Period

The following non-network projects have been or are currently being undertaken during the current *Regulatory Control Period*:

- a trial of high voltage capacitor banks to improve feeder power factor and voltage stability;
- the use of mobile/relocatable generation to manage peak demand on Bruny Island;
- a system wide review of projected short and long-term network limitations to identify opportunities for demand management solutions; and
- the removal of kW demand tariffs for new or modified customer connections.

14.5. Proposed non-network solutions and demand management projects

The following broad based programs are proposed for the 2012-17 *Regulatory Control Period*:

- a multi-year residential and small business load response project;
- a curtailable/distributed generation program with large commercial and industrial customers; and
- a trial to evaluate the impact of the utilisation of LED streetlight technology on system demand.

The following location specific programs are proposed for the 2012-17 *Regulatory Control Period*:

- water heating load control programs;
- residential, small commercial and industrial new construction demand management programs;
- larger commercial and industrial curtailable loads and embedded generation programs;
- community load response program;
- peak shaving with distributed storage/generation project; and
- power factor correction programs.

14.6. Outcomes

The benefits of these non-network initiatives will be:

- reduced capital expenditure and therefore lower price impacts on Aurora's customers;
- customer empowerment and greater customer choice;
- a decrease in individual customer's contribution to peak demand; and
- a reduction in customer average energy consumption.

15. Delivering Expenditure Programs

15. Delivering expenditure programs

Aurora is committed to meeting the reliability and investment requirements of its distribution electrical infrastructure, without contributing to additional price increases to customers. Aurora plans to meet this vision through a combination of:

- a review and realignment of its distribution engineering strategy;
- improvements in productivity through system and training improvements; and
- alternative external work options that are complementary to its work programs implemented throughout the State.

Aurora will position its business in such a manner that it can not only retain the right skills to complete its proposed work programs but also achieve those programs in a way that ensures that customers are provided with an efficient service delivery. Aurora is confident that it will have an efficient level of competent and skilled resources that are commensurate with the work programs it intends to deliver.

This commitment is further outlined as an attachment to this *Regulatory Proposal*.

15.1. Program of work delivery

Aurora's works planning process has undergone significant change in recent years to ensure:

- that all works planning occurs in a manner that maximises planning and strategic efficiencies;
- planning takes account of an efficient mix of internal and external resources; and
- programs are planned at a macro level to maximise efficiencies.

Allocation of work is distributed between the Aurora internal field work force and external contractors in order to maintain an appropriate balance of required skill levels, internal work force cost efficiency, peak demand periods and management of risk. Generally outsourced work incorporates activities that:

- are low in complexity but high in volume;
- meet peak work volumes;
- can be packaged as a single project, such as design and construction of zone substations;
- require civil maintenance and construction; or
- involve vegetation maintenance.

Outsourced projects are delivered through a separate project management group which operates under ISO 9001 quality accredited processes. This group utilises commercial procurement and contract management principles to ensure Aurora is receiving the most efficient delivery of the required service.

15.2. Program of work requirements

Aurora has carefully considered the requirements to maintain an efficient fully skilled workforce and has set an optimal service provision of approximately 625,000 labour hours for its field workforce. Aurora considers that this level of resourcing provides an efficient resourcing model, taking consideration of current available market conditions and resources whilst also allowing the necessary flexibility of delivery that takes account of weather, leave, training and peak work periods throughout the year.

15.3. Past delivery performance

The current *Regulatory Control Period* required the delivery of a significantly increased works program in comparison to previous regulatory periods, which represented a challenge to the business. Aurora met this challenge through a planned and staged building of works capability and delivery.

The major strategies employed over this period to ensure deliverability of the program included:

- apprentice program – Aurora has maintained an apprentice program that has focused on ensuring it is developing future resources;
- improvements in planning processes – enhancement in workload forecasting and levelling of the capital program for optimum design and construction efficiency within the program delivery;
- internal services focus – a directed focus on delivery of the distribution work programs and a reduction in the amount of external work being undertaken.
- design and construct contract – establishment of an increased and settled contractor presence; and
- outsourcing – in addition to the design and construct contract, Aurora also outsources other works via market contract arrangements particularly:
  - (i) where the internal Aurora model is not cost efficient;
  - (ii) where there is insufficient internal capability; or
  - (iii) during peak demand periods.

In employing these strategies, Aurora has successfully delivered a work program through both internal and externally-sourced service providers that was well in excess of that proposed to be delivered in the forthcoming *Regulatory Control Period*.

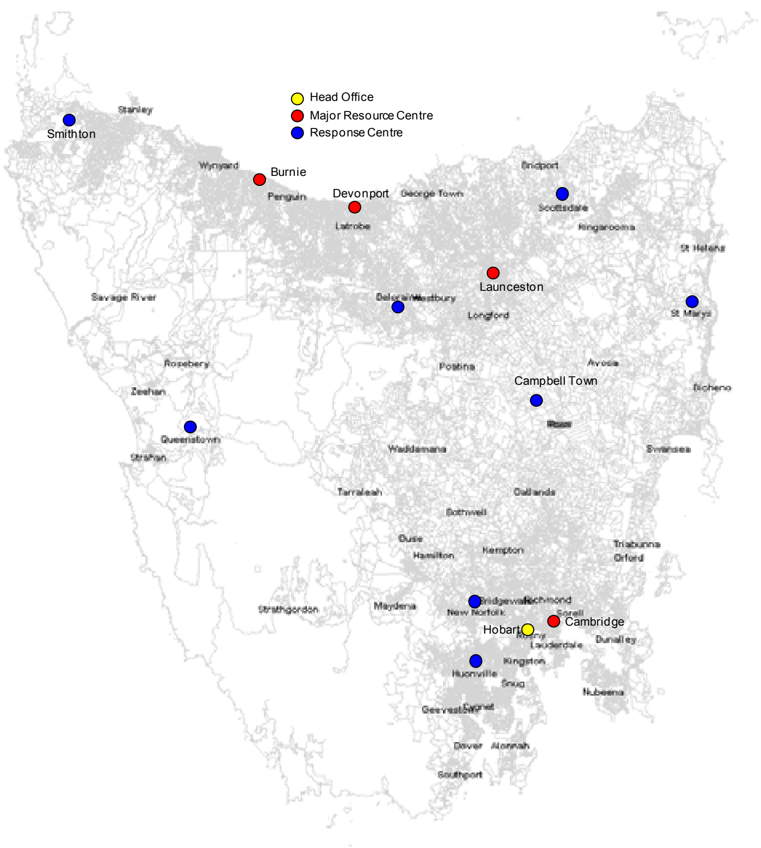
15.4. Future delivery requirements

15.4.1. Internal capability

Developing and maintaining the capability and availability of skilled resources is fundamental to delivery of any work program and skill maintenance and retention has been a major issue in the recent economic climate. Whilst Tasmania is small in geographical terms, it has quite a dispersed customer base, often in isolated or difficult to access areas. It is these challenges that have led to the establishment of a number of Major Resource Centres and Response Centres around the State, indicated in Figure 36.

Figure 36

Aurora's Operations



The workforce required to operate and maintain the distribution network has averaged approximately 475 personnel over the last three years with natural attrition and turnover being offset by an ongoing apprentice in-takes and targeted recruitment. Aurora has the capacity in place to assess both skill set requirements and volume of work and consequently deliver on any changes to the current resourcing strategy that may be required.

15.4.2. Apprentices

Aurora has spent significant time during the current *Regulatory Control Period* considering workforce planning and succession activities. It is acknowledged that staff require clear line of sight for career progression opportunities. These activities start with the apprentice program.

The apprentice program for 2011 has been suspended for one year in order to:

- ensure that Aurora's training centre construction upgrades, scheduled for 2011, to do not impede the timing or safety of apprentice training programs;
- allow for a review and improvement of all workplace documentation that relates to apprentices, including on call and supervision guidelines;
- allow for the changes in field leadership occurring as part of the distribution business strategic plan implementation; and
- be able to best match future workforce requirements to the program of work proposed in Aurora's *Regulatory Proposal*.

15.4.3. Training and competency

Aurora will continue to invest heavily in developing its staff and their workplace competencies. There is a large body of work taking place throughout Aurora that is focused on developing its workforce to achieve improved productivity and efficiencies and where necessary new skills required to meet the changing distribution environment. Some of these initiatives include:

- multi-skilling the workforce to create a field workforce capable of completing a majority of distribution activities without creating duplication and delivering greater workforce efficiencies;
- introduction of a planned competency framework aimed at identifying and rewarding competencies that contribute to business success, recognise workforce skills and capabilities; and
- Aurora's organisational wide commitment to training and development as evidenced within its corporate policies but also recent work in leadership enhancement, performance development and career and succession planning.

Aurora is implementing a five year plan that will focus on resource flexibility, in particular, dual trading for new recruits and as a transition program for current employees to enable them to work with greater flexibility. By multi-skilling its workforce, Aurora plans to increase workplace interest and challenges, provide a visual career path for both trade and non-trade specific employees and meet the increasingly diverse range of work programs that are evolving in the distribution and communication industries.

Resource flexibility allows Aurora to reduce its costs by means of increased work delivery capacity and improved career and remuneration opportunities for staff, whilst not relinquishing the importance of specialist roles to maintain risk mitigation and safety levels.

15.4.4. NBN and other external work

Given the strategies that Aurora is implementing within the distribution business, through improved planning, better scheduling and multi-skilling of the workforce, it is aiming to make significant cost savings in both operating and capital expenditure. However, as the primary service provider committed to a long-term presence in the State there are benefits in creating a critical mass to offset fixed overhead costs and maximise efficiencies.

The opportunities presented by other external work, such as NBN, provides a complementary business model that can be incorporated seamlessly into the business, thereby creating greater resource flexibility, easier management of peaks and troughs in core distribution work and more efficient overhead cost distribution. This balance is continually monitored through business planning processes and adjusted through changes identified in resource planning and external work opportunities.

15.4.5. Resource strategy

The distribution business has set itself a number of strategic initiatives relating to improving the operation of its entire distribution activities. The development of a comprehensive resourcing strategy is one such initiative that links together the internal resourcing requirements, contracting strategy, aging workforce, skill set requirements, and competency model in order to create the optimum level of field resources and leadership capability within the business.

15.4.6. Contracting strategy

As it operates on an island with limited capability to ramp up skilled resources quickly to meet peak demand loads, Aurora supports the introduction of increased competition in the service deliver area. A tender for major service provision to assist with delivery of Aurora's work program has been awarded, with the intent of establishing an ongoing presence in the State of other contractors with similar skill sets and capabilities.

In the short term it is assumed that a level of work will continue to be delivered via external parties; with decisions on outsourcing to be driven by skill set, location and peak demand periods. One of Aurora's key initiatives is to again formally review the mix of internal and external delivery across all services.

15.5. Conclusion

Aurora has made a concerted effort to prepare a considered deliverability strategy based on the planned future initiatives being undertaken, the size and capability of its workforce, support from external contract resources and supplementary service provision, that is optimal for delivery of the works program planned for the forthcoming *Regulatory Control Period* and will position the business for an ongoing delivery capability.

16. Shared Costs

16. Shared costs

Aurora's costs are either attributed directly on the basis of its direct costing approach; or allocated indirectly using shared cost allocation, which is consistent with the AER's Cost Allocation Guidelines. This chapter sets out the method by which forecast shared costs have been allocated to develop operating and capital expenditure forecasts for services provided by Aurora's distribution business.

Aurora's shared costs are those costs which are not directly attributable to the provision of a specific category of distribution service. The overarching principle adhered to by Aurora in allocating shared costs is that these should be allocated on a causal basis, unless the shared costs are immaterial or a causal relationship cannot be established without undue cost and effort.

Aurora applies two key methodologies to allocate its shared costs, being:

- the Indirect Cost Allocation Model (ICAM) which sets out the method for allocating corporate and shared services costs between Aurora's divisions and subsidiaries; and
- the Cost Allocation Method (CAM) which must be approved by the AER and is the method of allocating costs between various classifications within the distribution business.

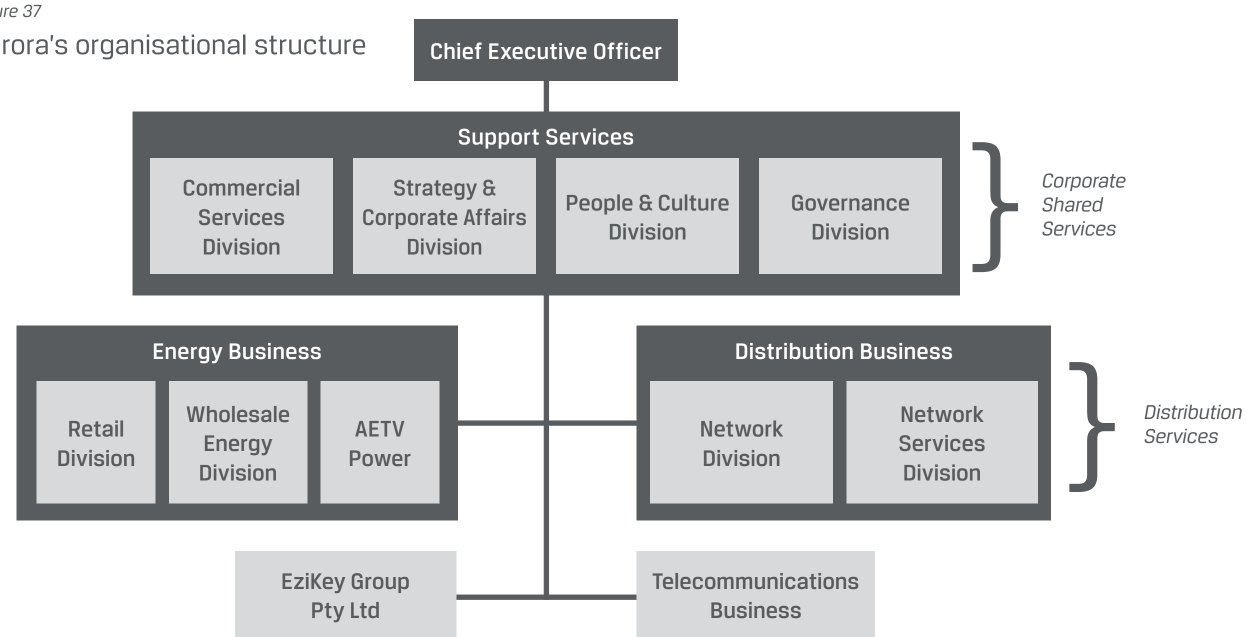
Aurora has five distinct shared cost pools that must be allocated to distribution services, being:

- *Network Services Division Corporate and Shared Service Costs* – this includes costs relating to Commercial Services; Strategy and Corporate Affairs; Governance; and People and Culture divisions;
- *Network Division Corporate and Shared Service Costs* – this includes costs relating to Commercial Services; Strategy and Corporate Affairs; Governance; and People and Culture divisions;
- *Distribution Business Shared Resource Services* – this includes costs relating to the Distribution finance team, the Distribution executive, and the Distribution safety team;
- *Network Services Division Management* – this includes costs relating to the support and management of the Network Services division; and
- *Network Division Management* – this includes costs relating to the management of the Network division.

Figure 37 below provides a high level overview of the Aurora organisational structure and therefore the relationships between these cost pools.

Figure 37

Aurora's organisational structure



16.1. Rules requirements

The *Rules* provide for the following matters of relevance in relation to shared costs:

- clause 6.5.6(b)(2) requires that the forecast of required operating expenditure in Aurora's Building Block Proposal must be for expenditure that is properly allocated to *Standard Control Services* in accordance with the principles and policies set out in the Aurora CAM;
- clause 6.5.7(b)(2) requires that the forecast of required capital expenditure in Aurora's Building Block Proposal must be for expenditure that is properly allocated to *Standard Control Services* in accordance with the principles and policies set out in the Aurora CAM;
- clause 6.7.1(1) states, among other matters, that the price for a *Negotiated Distribution Service* should be based on the costs incurred in providing that service, determined in accordance with the principles and policies set out in the Aurora CAM; and
- clause 6.15.4(f) provides that Aurora may, with the AER's approval, amend its CAM from time to time.

The Cost Allocation Guidelines provide for the following matters of relevance in relation to shared costs:

- clause 4.3 provides the AER, in consultation with Aurora, will review Aurora's CAM as part of this Distribution Determination; clauses 5.1(b)(1) and 5.1(b)(2) require that, without limiting the application of the CAM, Aurora must apply its CAM in preparing forecast operating and capital expenditure to be submitted to the AER in accordance with clauses 6.5.6 and 6.5.7 of the *Rules*; and
- clause 5.1(b)(3) requires that, without limiting the application of the CAM, Aurora must apply its CAM in preparing prices for a *Negotiated Distribution Service* determined in accordance with clause 6.7.1 of the *Rules*.

16.2. The Aurora CAM

Aurora's CAM, which is compliant with the requirements of the *Rules* and the Cost Allocation Guidelines, sets out its methodology for attributing direct costs and allocating indirect costs. Aurora confirms that the approach to allocating shared costs set out in this chapter is consistent with the approach set out in Aurora's CAM.

Aurora submitted its first CAM to the AER in December 2008 and was subsequently issued with its approval in June 2009. As noted in this AER-approved CAM, Aurora did not use this document specifically in the current *Regulatory Control Period*, although it was overall consistent with Aurora's cost allocation method used to prepare its expenditure forecasts for the current *Regulatory Control Period*.

The approved CAM was rendered inaccurate subsequent to the issue of AER's likely classification of Aurora's distribution services in November 2010. This was because the AER approved CAM detailed a methodology based on assumptions about the anticipated outcome of the AER's classification of Aurora's distribution services. These assumptions differed to the final classifications issued in the AER's Framework and Approach.

As the currently approved CAM is not consistent with the AER's approach to classification, it has been amended. In its currently approved CAM, Aurora stated its intention that any changes due to the AER's approach to classification of distribution services would be reviewed as part of this 2012-17 Pricing Determination. A proposed CAM has been submitted for AER approval as part of this *Regulatory Proposal* in accordance with clause 4.3 of the Cost Allocation Guidelines.

This proposed CAM is appended as an attachment to this *Regulatory Proposal*.

Aurora confirms that amendments to the CAM are consistent with the conditions upon which the AER will approve an amended CAM, as set out in clause 4.2(c) of the Cost Allocation Guidelines. This position has been corroborated by PricewaterhouseCoopers (PwC) which Aurora engaged to review the methodology set out in the proposed CAM.

16.3. Indirect cost allocation model

The ICAM is used by Aurora to allocate corporate and shared services costs between Aurora's divisions and subsidiaries. Costs are allocated based on the range of various cost drivers that have been approved under the ICAM.

Aurora's ICAM distinguishes between direct and indirect cost allocation on the following basis:

- direct costs are those with a strong causal relationship between the driver and the customer type; and
- indirect costs are those with a proxy relationship between the driver and the cost type.

Where a causal allocation can be established, costs are allocated on that basis. Where this is not possible, costs are allocated on a non-causal basis using a methodology that best reflects the use of the relevant services. Aurora notes that approximately 95 percent of the cost drivers used have a strong causal relationship with the associated cost category.

The following is noted in relation to the shared costs of the Aurora Corporate and Shared Services costs pool:

- corporate costs are largely fixed due to corporate governance requirements, and are therefore allocated by indirect cost drivers; and
- shared services costs are predominantly variable as they are driven by service request volumes, and are therefore allocated by direct cost drivers.

16.3.1. ICAM review

In developing the ICAM, comprehensive analysis was performed regarding the tasks undertaken; the costs incurred in undertaking the tasks; and the cost drivers for each group. This was achieved through a consultative process with Group Managers from the Office of the CEO, Commercial Services, People and Culture, Governance, and Strategy and Corporate Affairs divisions.

To review and confirm the appropriateness of the overhead and shared services costs allocation methodology applied by the ICAM, Aurora engaged the services of Deloitte. The Deloitte evaluation included an assessment of the appropriateness of the drivers and costs; and had regard to the extent to which such drivers were reliable, consistent, causal and material.

Deloitte concluded that Aurora's proposed allocation was appropriate provided that the recommended changes were implemented. The majority of Deloitte's recommendations have been subsequently implemented and Aurora considers that the methodology underpinning the ICAM is appropriate.

16.4. Allocation of shared costs

This section summarises Aurora's approach, with regard to the ICAM and CAM methodologies, for allocating shared costs to the Aurora distribution business; to the Network and Network Services divisions or externally; and then between distribution services. Shared cost allocation is based on actual costs, which determines the percentage split between service classifications.

Forecast costs for the overhead cost pools

Cost forecasts for each of the five shared cost pools are allocated on the following basis and are shown in Table 78.

Table 78

Shared cost pool allocation

Cost pool	Basis of allocation
Network Services Division Corporate and Shared Service	Labour hours for direct work.
Network Division Corporate and Shared Service	Operating expenditure is allocated on the basis of total operating expenditure. Capital expenditure is allocated on the basis of total operating and capital expenditure.
Distribution Business Shared Resources Services	Full time equivalent employees within each division.
Network Services Division	Labour hours for direct work.
Network Divisional Management	Percentage of total operating and capital expenditure.

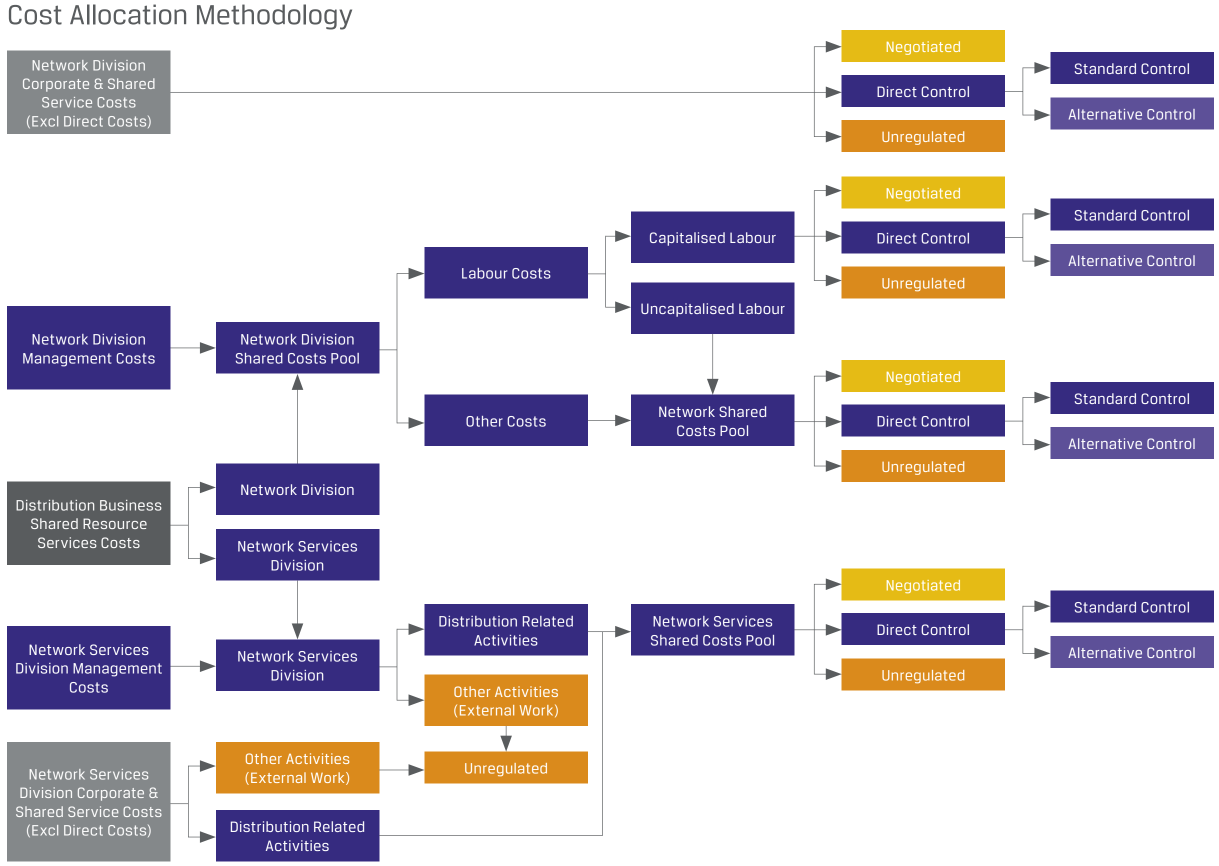
These cost pools represent the total pool of shared costs to be allocated between the Network Services and Network divisions, then to either *Direct Control Services*, *Negotiated Distribution Services* or *Unregulated Services*.

In accordance with clauses 6.5.6 and 6.5.7 of the *Rules*, Aurora confirms that the operating and capital expenditure forecasts included in its Building Block Proposal relate to shared expenditure that has been allocated in accordance with the methodology set out in the proposed CAM.

Figure 38 sets out a schematic summary of the method used to allocate expenditure to each service classification from each of these cost pools. It can be seen that the shared costs incurred by the Network division and the Network Services division are each split into service classifications in turn.

Figure 38

Cost Allocation Methodology



16.5. Prudency and efficiency of shared cost expenditure

Under clauses 6.5.6(c)(1)-(2) and 6.5.7(c)(1)-(2) of the *Rules*, the AER must accept Aurora's forecasts of capital and operating expenditure if it is satisfied that the total expenditure for the 2012-17 *Regulatory Control Period* reflects the operating and capital expenditure criteria. There are two expenditure criteria of relevance to *Standard Control Services* in this section, being that the expenditure must be:

- the efficient costs of achieving the expenditure objectives; and
- the costs that a prudent operator in Aurora's circumstances would require to achieve its capital and operating expenditure objectives.

This section will demonstrate the way in which the shared cost components of Aurora's capital and operating expenditure for *Standard Control Services*, as well as its other distribution services, is prudent and efficient.

The Aurora distribution business is structured to align with its overarching strategic objective of ensuring that there is no increase to customer prices as a result of its efforts, which is consistent with the prudency and efficiency requirements of the *Rules*.

Aurora confirms that the shared costs requirements represent the prudent and efficient costs of delivering its forecast work program. This is because these costs represent the efficient costs that a prudent operator would incur in order to support the delivery of its work program in Aurora's circumstances, based on realistic expenditure forecasts and cost inputs.

16.5.1. Prudency of shared cost expenditure

On the basis of its understanding of the operations of other DNSPs, Aurora considers that the shared costs required to deliver its work program over the forthcoming *Regulatory Control Period* represent prudent expenditure. This is because this expenditure provides critical support functions to the delivery of works and reflects standard industry practice. The rationale behind the establishment of key support functions provided by each shared cost pool is set out below.

In relation to the portion of the Corporate and Shared Services cost pool allocated to the distribution business, Aurora considers that these costs are incurred to provide critical support to the delivery of distribution services. These costs are associated with the following vital services:

- the Commercial Services division which is responsible for the organisation's financial and procurement strategies, financial discipline and cash flow management and financial reporting to key stakeholders;

- the Strategy and Corporate Affairs division which is responsible for the organisation's positioning from a business strategy and development perspective, market monitoring and policy development and public affairs and external relationships;
- the Governance division which is responsible for the provision of legal services, company secretariat, compliance, business risk and information services management. The GM Governance is also the Company Secretary and General Counsel; and
- the People and Culture division which focuses on the provision of systems and professional advice for attracting, retaining, motivating, managing, developing and rewarding the organisation's employees in line with Aurora's overall business strategic aims.

Similarly, distribution business expenses that are shared between the Network Services and Network divisions, are also incurred to support the delivery of distribution services. These costs are associated with the following vital services:

- the Distribution Finance team that provides specialist DNSP-related finance support for both divisions;
- the Distribution Executive that provides strategic direction and management for the distribution business as a whole; and
- the Distribution Safety team that is critical to ensure that Aurora is able to comply with its health and safety obligations.

The Network division is responsible for planning, operating and monitoring the distribution network, therefore network division management costs include labour and overhead costs associated with running the division.

The overhead costs incurred by the Network division include necessary management costs such as:

- fault and operations relating to labour and associated costs with manning switchboards and fault operators;
- the network customer group that facilitates the customer dispute process, implements and improves customer service strategies that meet customer needs and expectations, and administers the customer charter;
- regulatory costs relating to the preparation and delivery of regulatory submissions, information requests, responses, setting tariffs, revenue and pricing submissions;
- commercial services relating to the provision of commercial awareness and advice, financial services and analysis across the distribution business, and the preparation of Board reports, revenue recovery analysis, modelling, regulated and year end accounts, and policies and guidelines for the distribution business;
- asset management teams which are responsible for the management and planning of distribution assets;
- distribution IT systems relating to the management costs associated with strategic planning and IT architecture;
- executive teams - one business development executive team providing shared service across the two divisions (strategic vision, leadership);
- the market services team that has responsibility for NEM and retail competition related activities;
- compliance with all the metering and connection work undertaken, including the meter technical specification, metering procedures, work instructions and the Service and Installation Rules; and
- the IT licence fees and maintenance contractor and consultancy costs incurred running the business.

The Network Services division is responsible for delivery of the distribution work program; and the provision of a skilled workforce for the construction, operation and maintenance of the distribution network.

The overhead costs incurred by the Network Services division include management and support costs such as:

- the projects group responsible for proving project management expertise to both small and large scale projects. This projects group value-adds to the Network Services division by providing clarity around project timeframes, costs, quality and safety; and
- training centre costs – which are a critical component in ensuring that Aurora's workforce is appropriately trained for specific job functions.

The establishment of the above categories of support functions reflect standard industry practice and as such are used by other Australian DNSPs. Aurora therefore contends that expenditure on these functions reflects the prudent costs which are critical to achieve capital and operating expenditure objectives. These costs are necessary to support not only the delivery of *Standard Control Services*, but also those of *Alternative Control Services* and *Negotiated Distribution Services*.

16.5.2. Prudency of cost allocation to distribution business

As discussed in section , Aurora engaged Deloitte to review the suitability of the methodology applied in its ICAM, which is used to allocate corporate and shared services costs to Aurora's distribution business. Overall Deloitte concluded that the methodology was sound and the costs were reasonable. As discussed earlier the areas for improvement recommended through the review have been largely included in the current version of the ICAM.

As Deloitte provided an overall favourable assessment of the ICAM, and the majority of any recommendations were implemented, Aurora considers that the allocation of corporate and shared services is undertaken on an equitable basis. Therefore the expenditure allocated to the distribution business has been carried out in the most prudent manner.

16.5.3. Efficiency of shared cost expenditure

As referenced earlier in this *Regulatory Proposal*, Aurora's distribution business expenditure for the 2012-17 *Regulatory Control Period* will be driven by the objective of ensuring that there is no increase to customer prices as a result of its efforts. This means that Aurora is committed to securing value for money in its investments and the associated overhead costs, and operating efficiently.

In developing its shared costs expenditure forecasts Aurora has ensured that the forecasts of shared cost expenditure for the 2012-17 *Regulatory Control Period* comprise expenditure that represent the most efficient means of meeting its expenditure objectives.
Overall, expenditure forecasts have been prepared with regard to three concepts of efficiency, being:

- technical or productive efficiency which is achieved whereby the shared costs allocated to Aurora's work program support the delivery of the work program at the least cost;
- allocative efficiency where resources used to support the delivery of the work program provide the greatest benefit relative to costs; and
- dynamic efficiency which is achieved where Aurora implements changes to its overheads in response to changes in demand from the business.

16.6. Shared cost forecast for 2012-17 Regulatory Control Period

Table 79 sets out the forecast shared costs, by cost pool including escalations, for the 2012-17 *Regulatory Control Period*.

Table 79

Forecast shared costs

Shared cost pool ($2009-10)	2012-11 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Corporate and Shared costs – Network Services	17.847	17.669	17.624	17.630	17.630
Corporate and Shared costs – Network (opex)	13.394	13.364	13.374	13.386	13.386
Corporate and Shared costs – Network (capex)	14.684	15.852	13.886	11.348	11.327
Distribution Business shared costs	6.124	5.948	5.853	5.750	5.760
Network Services Management	22.134	21.393	20.605	19.823	18.950
Network Management	16.589	16.451	16.805	17.159	17.215
Total	**90.772**	**90.677**	**88.147**	**85.096**	**84.268**

17. Expenditure Escalations

17. Expenditure escalations

17.1. Introduction

In recent Distribution Determinations, the AER has allowed increases in annual capital and operating expenditure over the *Regulatory Control Period* that vary independently from inflation. Aurora considers it has developed a suite of similar escalation rates to be applied to capital and operating expenditure components. These are summarised in the section below.

17.2. Overview of escalators

A summary of Aurora's framework for its escalators is set out below, and in Table 80.

Material cost escalation rates: these rates were established on advice provided by Sinclair Knight Mertz (SKM) based on analysis drawing from its in-house "Capital Expenditure Cost Escalation Model". The escalators assess long-term trends in the costs of distribution equipment such as transformers, circuit breakers, conductors and poles, used in the construction and maintenance of the distribution network; as well as other equipment used in undertaking work on the network, such as vehicles, plant and tools. The materials portion of Aurora's capital expenditure is escalated across the 45 individual asset categories using the SKM materials escalators. Materials used in the provision of operating expenditure activities are escalated using the SKM materials escalator for "Distribution Equipment".

Labour cost escalation rate - this rate was established by SKM. The labour cost escalation rate is applied to the portion of capital expenditure costs allocated to labour (as distinct from materials, contractors and other), and the labour portion of operating expenditure. Aurora has set this escalation rate at CPI, which means that it has forecast no real increases in labour costs for the term of the *Regulatory Control Period*.

Contractor cost escalation rates – these rates were established on advice provided by SKM, and are applied to that portion of costs incurred by employees and contractors in the delivery of the capital expenditure and operating expenditure programs, respectively.

Other cost escalation rates – these rates were determined by Aurora internally. They are applied to components of the capital and operating expenditure programs other than labour, materials and contractors costs. Aurora has set this escalation rate at CPI, which means that it has forecast no real increases in other costs for the term of the *Regulatory Control Period*.

Table 80

Methodology used to determine 2012-17 escalation rates by category

	Capital expenditure	Operating expenditure
Material cost escalation	SKM's Capital Expenditure Cost Escalation Model.	SKM's Capital Expenditure Cost Escalation Model – "Distribution Equipment" category.
Labour cost escalation	No escalation in real terms.	No escalation in real terms.
Contractor cost escalation	No escalation in real terms.	No escalation in real terms.
Other Cost escalation	No escalation in real terms.	No escalation in real terms.

17.3. Rules requirements

There are no specific *Rules* requirements relating to this *Regulatory Proposal* and the methodology and values used to escalate expenditure over its 2012-17 *Regulatory Control Period*, however Aurora's RIN as issued by the AER in April 2011, requires that for labour and materials escalators, Aurora must:

- identify the labour and material escalators used in the estimation of the forecast capex and opex proposals;
- provide:
  - the escalator used in percentage terms for each *Regulatory Year*;
  - a copy of the model(s) that have been used to derive and apply the escalators; and

  › a copy of Aurora's current Enterprise Bargaining Agreement.
- identify:
  › the portion of the forecast capex and opex proposals which is due to a change in escalator; and
  › whether the escalator is in real or nominal terms.
- explain:
  › the methodology underlying the calculation of each escalator;
  › the weightings given to each escalator for each capex and opex category and how those weighting have been developed;
  › whether the same expenditure escalators have been used for the forecast capex and opex proposals;
  › why it is appropriate for different expenditure escalators to apply;
  › whether the expenditure estimation process for the escalators involves the application of contingency factors; and
  › how the weightings given to each escalator are expected to change over the *Regulatory Control Period*.

Aurora notes that:

- it did not include any contingency factors in its capital and operating expenditure forecasts for the 2012-17 *Regulatory Control Period*; and
- references to escalation rates are in real terms (unless otherwise specified).

The remainder of these issues are addressed throughout this chapter.

17.4. Materials expenditure escalators

Aurora's materials cost escalation factors apply to its capital and operating expenditure forecasts in addition to CPI inflators. This approach was taken on the basis that movements in the CPI do not accurately reflect the movements in nominal costs related to Aurora's work program.

There is precedent for this approach in the AER's most recent Distribution Determinations in New South Wales, Queensland and Victoria. The methodologies accepted by the AER in its recent Distribution Determinations modelled the changing price of equipment and project costs through the application of independent forecast movements in the price of input components to weightings for the relative contribution of each component to final equipment or project costs.

Aurora engaged SKM to prepare material escalation rates for 45 asset categories from 2009-10 to 2016-17. SKM's terms of engagement and expert report are appended as an attachment to this *Regulatory Proposal*.

17.4.1. Capital expenditure methodology and rates

SKM completed its report having regard for recent AER Determinations and Aurora's operating environment.

SKM's methodology is set out below, being that it:

(1) carried out procurement studies with seven TNSPs and nine DNSPs operating in the Australian electricity industry. This study involved the survey of these participants to provide confidential contract information for the purchase of common items of plant, equipment and materials for the period spanning 2002-09;

(2) identified, on the basis of economic analysis, the following key cost drivers impacting the rises in network capital expenditure:

  (i) oil;

  (ii) construction costs;

  (iii) the Trade Weighted Index, which was set to CPI;

  (iv) metals such as copper, aluminium, and steel;

  (v) foreign exchange rates, particularly the US$/AUD relationship;

  (vi) wood poles, which was set to CPI; and

  (vii) other cost components including suppliers' transport costs and profit margins sought in the supply chain, to which CPI is assigned as a proxy for cost escalation;

(3) forecast average annual real changes in each of the key cost drivers forecast over 2010-17, which are set out in Table 81.

Table 81

Average annual real change materials key cost drivers

Cost driver	Jun 2012	Jun 2013	Jun 2014	Jun 2015	Jun 2016	Jun 2017
Aluminium	17.02%	-1.07%	-1.12%	-2.98%	-2.69%	-2.08%
Copper	17.79%	-6.04%	-7.69%	-10.45%	-10.76%	-10.86%
Steel average	13.30%	-2.53%	-1.40%	-3.05%	-2.76%	-2.15%
Oil	8.73%	-4.76%	8.71%	-3.33%	-8.88%	1.09%
Construction costs	-0.26%	-2.95%	-1.60%	1.05%	2.79%	2.91%
CPI	2.75%	3.00%	2.50%	2.50%	2.50%	2.50%

(4) assigned individual cost component weightings for each project component. This involved the examination of each of the main items of plant equipment and materials within its database to establish a suitable weighting, by which each underlying cost driver was considered to influence the total price of each completed item; and

(5) modelled the annual movement in cost of each network asset by applying weightings to each component, and applying forecast movements in the Key Cost Drivers. SKM's cost escalation model forecast the likely impact of expected movements of specific input cost drivers on future electricity infrastructure materials costs. This is set out for each individual asset category in Table 82.

Table 82

Materials escalation rates for capital expenditure

Asset category	Jun 2012	Jun 2013	Jun 2014	Jun 2015	Jun 2016	Jun 2017
Overhead sub-transmission lines	1.018	0.998	0.990	0.977	0.968	0.967
Underground sub-transmission cables	1.103	1.078	1.061	1.024	0.986	0.960
Overhead distribution lines	1.043	1.027	1.031	1.013	0.990	0.981
Underground distribution cables	1.015	1.002	1.009	0.997	0.980	0.979
Distribution equipment	1.041	1.027	1.028	1.012	0.991	0.983
Substation bays	1.007	0.991	0.989	0.981	0.973	0.974
Substation establishment	0.923	0.895	0.881	0.890	0.915	0.942
Distribution substation switchgear	1.041	1.027	1.028	1.012	0.991	0.983
Transformers (zone + distribution)	1.074	1.052	1.046	1.019	0.988	0.971
Distribution substations	1.054	1.032	1.025	1.002	0.978	0.967
Low voltage services	1.045	1.037	1.030	1.011	0.994	0.982
Metering	1.018	1.010	1.015	1.007	0.993	0.990
Communications - pilot wires	1.000	1.000	1.000	1.000	1.000	1.000
Generation assets	1.047	1.031	1.031	1.013	0.991	0.981
Street lighting	1.019	1.013	1.010	1.004	0.998	0.994
Other equipment	1.000	1.000	1.000	1.000	1.000	1.000
Control centre - SCADA	1.000	1.000	1.000	1.000	1.000	1.000
Communications	1.000	1.000	1.000	1.000	1.000	1.000
IT systems	1.000	1.000	1.000	1.000	1.000	1.000
Office equipment & furniture	1.000	1.000	1.000	1.000	1.000	1.000
Motor vehicles	1.000	1.000	1.000	1.000	1.000	1.000
Plant & equipment	1.000	1.000	1.000	1.000	1.000	1.000
Buildings	0.923	0.895	0.881	0.890	0.915	0.942
Steel poles	1.048	1.028	1.034	1.015	0.988	0.980
Concrete poles	0.923	0.895	0.881	0.890	0.915	0.942
Switchgear	1.041	1.027	1.028	1.012	0.991	0.983
Transformers	1.074	1.052	1.046	1.019	0.988	0.971
Structure	0.923	0.895	0.881	0.890	0.915	0.942
Foundation	0.923	0.895	0.881	0.890	0.915	0.942
Civil	0.923	0.895	0.881	0.890	0.915	0.942
P&C	1.018	1.010	1.015	1.007	0.993	0.990
Conductor	1.045	1.037	1.030	1.011	0.994	0.982
Towers	1.009	0.981	0.967	0.955	0.954	0.956
Insulators	1.009	0.996	1.018	1.009	0.986	0.989
Fittings	1.030	1.013	1.031	1.014	0.984	0.981
Foundations	0.923	0.895	0.881	0.890	0.915	0.942
Wood poles	1.000	1.000	1.000	1.000	1.000	1.000
Cable Al	1.033	1.023	1.027	1.011	0.990	0.983
Cable Cu	1.222	1.172	1.120	1.047	0.977	0.919
PVC Conduit	1.010	0.996	1.021	1.011	0.983	0.986
Pit	0.923	0.895	0.881	0.890	0.915	0.942
Cable protection	0.923	0.895	0.881	0.890	0.915	0.942
Misc material	1.033	1.013	1.031	1.014	0.984	0.981
Standby generators	1.047	1.031	1.031	1.013	0.991	0.981

As movements in CPI do not necessarily reflect movements in material costs associated with electricity network projects, adjusting for material cost escalators, in real terms, will result in both increases and decreases in cost drivers and therefore material cost components of various network assets. This means that in real terms some asset forecasts will increase compared to actual capital expenditure from the current *Regulatory Control Period*, and other assets forecasts will decrease.

SKM applied a range of assumptions in relation to underlying economic key cost drivers and forecasts to define and forecast future movements in the key cost drivers. These are detailed in full in the SKM report, and summarised below as follows:

- *CPI* – was forecast using the method used by the AER in the Final Decision for NSW distribution businesses, using two years of forecasts from the most recent RBA Monetary Policy Statement (the February 2011 Monetary Policy Statement Forecasts are available for years ending June 11 and June 12)[1] and thereafter SKM assumed CPI as the RBA inflation target's midpoint of 2.5 percent.
- *US$ to AUD Exchange rate* – was forecast using the average monthly US$ / AUD exchange rates, to restate US$ based market prices of copper, aluminium, steel and oil into comparable Australian dollar pricing movements. This was undertaken in order to account for potential movements of base currency commodity market price movements through strengthening or weakening of the Australian dollar.
- *The Trade Weighted Index* – CPI was assumed on the basis that the AER has not been satisfied with the evidence of real cost escalation for presented in previous *Regulatory Proposals*. No new evidence has become available since that time.
- *Wood Poles* – was set to CPI on the basis that the AER has not been satisfied with the evidence of real cost escalation presented in previous *Regulatory Proposals*. No new evidence has become available since that time.
- *Contractor's Margin* – was forecast using movements in construction costs as a proxy for information on contractor's margins, as SKM considered that a contractor would pass on the cost of doing business to the end-user.
- *Producer's margin* – was set to CPI on the basis that there are no credible forecasts for future producer's margins for the periods comprising Aurora's forthcoming *Regulatory Control Period*.
- *Construction costs* – was forecast using estimates of related construction costs and annual growth rates developed by the Construction Forecasting Council (CFC). SKM has adopted these estimated movements (presented as Australian National "Engineering" Construction Cost Forecasts) as the likely movements in the construction cost component of relevance to Aurora for cost escalation modelling.
- *Commodity prices* – incorporates the use of commodity futures contract prices into cost escalation rate computations. This employs various combinations of futures contract prices and a range of views from credible forecasting professionals to develop likely year to December price positions of specific key cost components.

1 Reserve Bank of Australia, *Statement on Monetary Policy – February 2011*.

17.4.2. Operating expenditure methodology and values

Materials used in the provision of operating expenditure activities are escalated using the SKM materials escalator for "Distribution Equipment". The "Distribution Equipment" escalation rates to be applied to operating expenditure materials cost forecasts over the 2012-17 *Regulatory Control Period* are set out in Table 83:

Table 83

Materials escalation rates for operating expenditure

Asset category	Jun 2012	Jun 2013	Jun 2014	Jun 2015	Jun 2016	Jun 2017
Operating expenditure escalation rates	1.041	1.027	1.028	1.012	0.991	0.983

As the escalation factors for this category were determined using the SKM Capital Expenditure Cost Escalation Model, the methodology used is identical to that set out above for the individual capital expenditure categories. That is, forecast cost escalation for the "Distribution Equipment" category used the following high level process:

- carried out procurement studies with Australian TNSPs and DNSPs;
- identified key cost drivers impacting on network expenditure;
- forecast average annual real change in each of the key cost drivers;
- established a suitable weighting by which the underlying cost drivers were considered to influence the total price of "Distribution Equipment";
- assigned individual cost component weightings for each project component of "Distribution Equipment"; and
- modelled the annual movement in cost of each network asset by applying weightings to each component, and applying forecast movements in the key cost drivers.

The assumptions applied to determining escalators for operating expenditure are identical to those used to develop SKM's forecast capital expenditure escalators, and are discussed above in section 17.4.1.

17.5. Labour expenditure escalators

In anticipation of achieving significant efficiencies in labour costs for both its operating and capital expenditure programs, Aurora has applied an escalation rate equal to zero for the delivery of its entire work program. Therefore labour costs will increase in accordance with CPI only, which has been forecast in accordance with the SKM report.

Aurora will achieve these efficiencies through the implementation of its strategic plan over the forthcoming *Regulatory Control Period*. Under this plan Aurora will be implementing a range of changes to the delivery of its work program to meet the overarching distribution business strategic objective of ensuring that it will "not contribute to any price increases to the customer as a result of its efforts". In accordance with strategies developed to meet this objective Aurora anticipates that there will be significant efficiencies achieved in labour costs.

Aurora notes that the AER allowed a one percent per annum real escalation rate in its recent Final Determination for the Victorian DNSPs. Nonetheless Aurora is confident of achieving efficiencies in its labour costs over the 2012-17 *Regulatory Control Period* and does not consider that an increase in labour costs over and above CPI is reflective of efficient costs.

Table 84

Labour escalation rates for capital and operating expenditure

Cost driver	Jun 2012	Jun 2013	Jun 2014	Jun 2015	Jun 2016	Jun 2017
Labour escalation rates	1.000	1.000	1.000	1.000	1.000	1.000

17.6. Contractor expenditure escalators

Aurora engaged SKM to develop expenditure escalators for its contractor costs, for both capital and operating expenditure over the 2012-17 *Regulatory Control Period*.

In 2007 the Essential Services Commission (ESC) of Victoria requested the Allen Consulting Group (ACG) to review two reports commissioned by Envestra, and presented in support of the costs incurred in opex activities within a gas distribution network under an outsourced services contract.

ACG concluded that the use of earnings before interest and taxation as a proportion of revenue was the most appropriate measure of a contractor's margin. However, in comparing these measures of a contractor's margin, ACG concluded that other considerations, such as whether or not arms-length agreements were in place, whether the companies were engaged in undertaking the same principal activity, the overall size of the contractor (with smaller firms being excluded), and its relative level of capital intensity, all affected the relative degree of comparability.

These difficulties in gathering comparable information on contractor's margins, also only pertain to historic costs, as they would be taken from published financial reports.

Indeed, SKM found there was a lack of credible information regarding forecasts of the likely margins that contractors would be able to claim in the years corresponding to Aurora's forthcoming *Regulatory Control Period*.

In the absence of any such forecast, Aurora applied a rationale similar to that used for labour escalation rates set out in section 17.5. That is, Aurora assumed no real increases in contractor costs for 2012-17 *Regulatory Control Period*.

Table 85 sets out the escalators that will be applied to estimate contractor costs, for both capital and operating expenditure, for the 2012-17 *Regulatory Control Period*.

Table 85

Contractor cost escalation rates for capital and operating expenditure

Cost driver	Jun 2012	Jun 2013	Jun 2014	Jun 2015	Jun 2016	Jun 2017
Contractor costs escalation rates	1.000	1.000	1.000	1.000	1.000	1.000

17.7. Other expenditure escalators

In forecasting escalation rates for other costs, Aurora applied a rationale similar to that used for labour escalation rates set out in section 17.5. That is, Aurora has assumed no real increases in other costs for the 2012-17 *Regulatory Control Period*. This is in anticipation of achieving efficiencies across both its operating and capital expenditure programs.

Table 86

Forecast other escalation rates for capital and operating expenditure

Cost driver	Jun 2012	Jun 2013	Jun 2014	Jun 2015	Jun 2016	Jun 2017
Other costs escalation rates	1.000	1.000	1.000	1.000	1.000	1.000

18. Unit Rates

18. Unit rates

Aurora utilises unit rates as a key input for determining its capital and operating expenditure programs where similar projects or tasks are undertaken. Unit rates are applied to key items of plant and equipment for both labour and material unit costs. The unit rates currently incurred by Aurora, and reflected in the current average costs of works, have been utilised as the basis for future unit rates.

Aurora derives its input costs on the basis of the current average costs of undertaking similar projects and capital and operating work programs over the current *Regulatory Control Period*. Where a project is unique in nature, Aurora undertakes bottom-up project estimation based on the design components.

These unit rates represent an aggregation of materials and other costs required to complete the works.

In the preparation of its unit rates for labour; plant and equipment; and materials, Aurora engaged the services of SKM to review the factors likely to affect the escalation of input costs between 2009-10 to 2016-17. An overview of expenditure escalators and the adopted methodology are covered in chapter 17 of this *Regulatory Proposal*.

18.1. Utilisation of unit rates

Aurora applies unit rates to specific tasks within work programs that are of a repetitive nature and are contained within the operating and capital expenditure programs of work, for example pole replacements, transformer installations, replacement of conductor etc. Where there is more than one task within a work program, the unit rate is applied to the volume of tasks to arrive at an overall program cost.

18.2. Determining the unit rates

Aurora's unit rates have been determined using a bottom-up approach by aggregating the following:

- estimated labour time required to undertake the task multiplied by the hourly rate of the skill sets utilised;
- materials; and
- plant and equipment.

18.3. Network Services overheads

Network Services overheads are determined for both labour and other costs. Labour overheads include the labour costs of staff not directly billable to tasks. Skills that fall into this category include management, administration staff, apprentices and executive. Other overhead costs include tools, equipment, office supplies and travel costs.

The apportionment of total overhead costs is based on the total number of billable hours which is in turn applied to unit rates based on the estimated time. Overhead costs are further covered in chapter 16 of this *Regulatory Proposal*.

18.4 Prudency and efficiency of unit rates

Under clauses 6.5.6(c)(1)-(2) and 6.5.7(c)(1)-(2) of the *Rules*, the AER must accept Aurora's forecasts of capital and operating expenditure if it is satisfied that the total expenditure for the 2012-2017 *Regulatory Control Period* reflects:

- the efficient costs of achieving the expenditure objectives; and
- the costs that a prudent operator in Aurora's circumstances would require to achieve its capital and operating expenditure objectives.

This section will demonstrate the way in which the unit rates contained within Aurora's capital and operating expenditure for *Standard Control Services*, as well as its other distribution services, is prudent and efficient.

The Aurora distribution business is structured to align with its long-term aspirational objective of ensuring that there is no increase to customer prices as a result of its efforts, which is consistent with the prudency and efficiency requirements of the *Rules*. In keeping with this strategic objective Aurora has also applied an efficiency factor to the labour rates within the unit rates. This efficiency factor results in a real reduction within the labour rates in excess of 10 percent over the period of the forthcoming *Regulatory Control Period*.

Aurora confirms that the unit rates contained within the capital and operating expenditure programs represent those that a prudent and efficient operator would apply.

On the basis of its understanding of the operations of other DNSPs, Aurora considers that the unit rates contained within its work program over the forthcoming period are prudent. This is because the unit rates have been derived from a bottom-up approach.

18.5 Benchmarking unit rates

In demonstrating the efficiency of its unit rates, Aurora engaged Parsons Brinckerhoff (PB) to undertake a benchmarking study of Aurora's forecast capital and operational expenditure. The benchmarking framework adopted for the study included a review of Aurora's 10 most material unit rates compared to costs covering other Australian distribution businesses available to PB. The work programs comprising the selected unit rates for comparison accounted for 52 percent of Aurora's total operational and capital work programs.

The PB benchmarking study identified that the unit rates within Aurora's capital and operational expenditure programs were generally aligned with or below industry expectations when normalised using a range of comparators. The PB capital and operating expenditure benchmarking study is appended as an attachment to this *Regulatory Proposal*.

19. Regulatory Asset Base

19. Regulatory asset base

19.1. Rules requirements

Clause 6.5.1 of the *Rules* describes the nature of the regulatory asset base (RAB). The *Rules* require the AER to develop and publish a model for the roll forward of the RAB and provide the requirements for that roll forward model (RFM).

The *Rules* further require that Aurora establish the RAB at the commencement of the forthcoming *Regulatory Control Period* (1 July 2012) and then roll forward that RAB consistent with the AER's RFM.

Schedule 6.1.3(7) of the *Rules* requires Aurora's Building Block Proposal to contain a calculation of the RAB for each year, using the RFM, together with:

- details of all amounts, values and other inputs;
- a demonstration that the amounts, values and inputs comply with the relevant requirements of Part C of Chapter 6 of the *Rules*; and
- an explanation of the calculation of the RAB for each year and of the amounts, values and other inputs involved in the calculation.

Schedule 6.1.3(10) of the *Rules* requires Aurora's Building Block Proposal to contain a completed post tax revenue model (PTRM) and RFM.

Other provisions relating to the RAB are set out in schedule 6.2 of the *Rules*. In particular:

- subclause 1(c)(1) establishes a value for the RAB of Aurora as at 1 January 2008, by reference to the RAB value used by OTTER in the current *Regulatory Control Period*;
- subclause 1(c)(2) specifies how this initial value is to be adjusted for the difference in estimated and actual capital expenditure in the previous *Regulatory Control Period*;
- subclause 1(e) specifies the method of adjustment of value of the RAB between *Regulatory Control Periods*; and
- subclause 3 specifies the method of adjustment of value of the RAB for each year within a *Regulatory Control Period*.

This chapter outlines the methodology adopted by Aurora to roll forward its RAB. Information is also provided on forecast capital expenditure and disposals. Details of the establishment of the RAB value as at 1 July 2012 and summaries of the roll forward value of the asset base over the 2012-17 *Regulatory Control Period* are also provided.

19.2. Summary

Aurora's nominal opening RAB (as at 1 July 2012) value of $1,484.86 million is based on:

- the RAB value as prescribed by the *Rules*;
- adjustments as provided by the *Rules*;
- depreciation during the current *Regulatory Control Period*;
- actual capital expenditure during the current *Regulatory Control Period* (net of capital contributions);
- actual disposals (based on written down book value) during the current *Regulatory Control Period*;
- actual inflation during the current *Regulatory Control Period*; and
- estimates of capital expenditure and disposals for the 2010-11 and 2011-12 financial years.

Table 87 summarises Aurora's forecast of the RAB over the 2012-17 *Regulatory Control Period*.

Table 87

RAB – 2012-17

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Opening RAB – 1 July	1,484.86	1,572.70	1,659.18	1,747.16	1,840.51
Forecast capital expenditure	153.39	159.17	158.77	157.52	163.64
Forecast straight line depreciation	83.33	91.76	90.90	86.19	88.14
Forecast disposals	0.75	1.08	1.69	1.55	1.59
Forecast customer contributions	20.96	21.50	22.06	22.63	23.21
Closing RAB – 30 June	1,533.22	1,617.53	1,703.30	1,794.31	1,891.21

19.3. Establishment of the RAB value at 1 January 2008

19.3.1. Specified RAB value as at 1 January 2008

Schedule 6.2.1(c)(1) of the *Rules* specifies the opening RAB for Aurora as $981.108 million, in July 2006 dollars.

19.3.2. Adjustment to the 1 January 2008 RAB value for capital expenditure

The specified value of $981.108 million is required to be adjusted, as specified in Schedule 6.2.1(c)(2) of the *Rules*, for the difference between:

- any estimated capital expenditure that is included in those values for any part of a previous *Regulatory Control Period*; and
- the actual capital expenditure for that part of the previous *Regulatory Control Period*.

In setting the asset value as part of the 2007 Pricing Determination OTTER was required to estimate the capital expenditure that would occur until 1 January 2008. As the RAB value was to be set at a point mid way through a financial year (2007-08) and the last available ring-fenced accounts provided by Aurora covered the financial year ended 30 June 2006; OTTER was required to estimate Aurora's capital expenditure for the period 1 July 2006 – 31 December 2007 or a period of eighteen months. The adjustment to Aurora's 1 January 2008 RAB will therefore require a similar treatment.

Establishing 1 July 2007 RAB value

The establishment of Aurora's opening RAB at 1 January 2008 provides a number of uncertainties regarding an appropriate methodology to allow an assessment of the differences between actual and forecast expenditure. Aurora has therefore removed from the 1 January 2008 RAB valuation OTTER forecast allowances for capital expenditure, asset depreciation, capital contributions and asset disposals for the period 1 July 2007 to 31 December 2007.

This has enabled Aurora to establish a RAB value commencing at the conclusion of the 2006-07 financial year, or 1 July 2007.

Establishment of a RAB valuation at this point in time allows Aurora to compare a full financial year OTTER forecast with actual outcomes and utilise those differences into the AER's RFM.

Aurora has removed the OTTER forecast amounts for capital expenditure, asset depreciation, capital contributions and asset disposals for the period 1 July 2007 to 31 December 2007.

These differences then provide an adjusted RAB value for the financial year commencing 1 July 2007.

Table 88 summarises Aurora's adjustments to the 1 January 2008 opening RAB.

Table 88

RAB – 1 January 2008

July 2006 dollars	($m)
Opening RAB – 1 January 2008	981.108
Capital expenditure forecasts 1/7/2007 – 31/12/2007 (net)	48.28
Asset depreciation forecasts 1/7/2007 – 31/12/2007	30.36
Asset disposal forecasts 1/7/2007 – 31/12/2007	1.20
Adjusted 1 July 2007 RAB	964.40

Adjustments for 2006-07 financial year

As the establishment of Aurora's opening RAB at 1 January 2008 also included an estimation of such amounts for the 2006-07 financial year, a similar treatment to that undertaken above to arrive at the adjusted RAB value at 1 July 2007 is also required.

Aurora has removed the OTTER forecast amounts for capital expenditure, asset depreciation, capital contributions and asset disposals for the period 1 July 2006 to 30 June 2007.

These differences then provide an adjusted RAB value for the financial year commencing 1 July 2006.

This opening RAB value has been input into the AER's RFM.

Table 89 summarises Aurora's adjustments to the 1 July 2007 opening RAB.

Table 89

RAB – 1 July 2007

July 2006 dollars	($m)
Adjusted RAB – 1 July 2007	964.40
Forecast capital expenditure 2006-07 (net of customer contributions)	112.60
Forecast straight line depreciation 2006-07	55.54
Forecast disposals 2006-07	0.86
Opening RAB 1 July 2006	908.20

19.4. Roll forward of the RAB to 30 June 2012

19.4.1. Methodology used to roll forward the RAB value

Aurora has applied the methodology set out in schedule 6.2 of the *Rules* and has used the AER's RFM.

As required by clause 6.5.5(b)(3) of the *Rules*, depreciation has been applied using the same prime cost methodology and same asset lives as applied in OTTER's 2007 Determination.

19.4.2. Assumptions applied to the RAB roll forward

Aurora has made a number of assumptions in the roll forward of the RAB to 30 June 2012.

Adjustment for inflation

The RAB has been indexed each year in a manner consistent with the annual price adjustments in the current *Regulatory Control Period*.

Indexation of the RAB for the years ended 30 June 2008 to 30 June 2012 has been determined by applying the actual All Groups CPI, Weighted Average of Eight State Capital Cities (published by the Australian Bureau of Statistics) for the years to 30 June 2007 to 2010 respectively.

Remaining asset lives

The RAB is currently held within Aurora's ring-fenced accounts with capitalised additions added for each year since the establishment of the asset base by OTTER in 1998. These yearly additions are held as individual sub-categories of the asset class and have been aggregated to a single category with a weighted average remaining life for inclusion in the RFM and PTRM.

Disposals of assets

Asset disposals largely comprise assets such as vehicles, land and buildings. Asset disposals are recognised in the year of disposal, with the written down value deducted from the RAB.

Assumptions for the 2010-11 and 2011-12 Regulatory Years

At the time of preparing this *Regulatory Proposal*, actual data for the 2010-11 and 2011-12 *Regulatory Years* for capital expenditure, depreciation and asset disposals is not available.

Forecast capital expenditure and asset disposal data for 2010-11 has been applied in this *Regulatory Proposal*, with depreciation calculated accordingly. The roll forward will be adjusted in the revised *Regulatory Proposal* to reflect actual 2010-11 data.

The actual data for 2011-12 will not be available for the AER's final Determination. Therefore the roll forward has applied Aurora's estimate of the 2011-12 capital expenditure. The difference between this amount and the actual amount will be reflected in the RAB roll forward for 2017-22

Table 90 summarises Aurora's roll forward of the RAB over the 2006-12 period.

Table 90

RAB – 2006-12

Nominal dollars	2006-07 ($m)	2007-08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Opening RAB – 1 July	908.20	984.14	1,072.22	1,156.57	1,266.62	1,384.85
Capital expenditure[1]	111.73	116.15	138.92	154.09	172.26	152.45
Depreciation	54.87	61.28	60.17	69.26	71.05	72.85
Customer contributions		10.52	9.48	8.89	10.19	10.43
Disposals		0.55	1.00	1.16	4.45	0.89
Closing RAB – 30 June	965.06	1,027.93	1,140.49	1,231.35	1,353.18	1,453.13
Inflation rate	2.10%	4.50%	1.50%	3.05%	2.50%	2.75%

1 Capital expenditure is net of capital contributions and disposals.

19.4.3. Adjustments applied by the AER's RFM

There are a number of adjustments that are applied by the AER's RFM to the closing RAB value at 30 June 2012 prior to the commencement of the forthcoming *Regulatory Control Period*. These adjustments are required for the differences between actual and forecast capital expenditure, a return on the difference between actual and forecast capital expenditure and to establish the opening value of the RAB for the forthcoming *Regulatory Control Period*.

Table 91 summarises the RFM adjustments to the 30 June 2012 closing RAB.

Table 91

RFM RAB – 30 June 2012

	($m)
Closing RAB – 30 June 2012	1,453.13
Difference between actual and forecast capital expenditure (net)	(21.85)
Return on difference	(9.12)
RFM adjustment to closing RAB	38.08
RFM closing RAB 30 June 2012	1,460.24

19.5. Roll forward of the RAB from 1 July 2012 to 30 June 2017

19.5.1. Methodology used to roll forward the RAB value

Aurora has modelled the roll forward of the RAB for the forthcoming *Regulatory Control Period* based on the closing RAB value of $1,460.24 million as at 30 June 2012, as detailed in section 19.4 above.

Aurora has applied the methodology set out in schedule 6.2.1 of the *Rules* and has used the AER's PTRM.

19.5.2. Assumptions applied to the RAB roll forward

Aurora has made a number of assumptions in the roll forward of the RAB to 30 June 2017.

Work-in-progress

The opening balance of work-in-progress at 1 July 2012 is estimated based on the work-in-progress balance at 30 June 2011. The *Regulatory Proposal* reflects the forecasted value for work-in-progress at 30 June 2011. This forecast will be updated in Aurora's revised *Regulatory Proposal* for the actual balance of work-in-progress at 30 June 2011.

Forecast expenditure

Forecast capital expenditure (net of customer contributions) has been applied, as detailed in chapter 11 of this *Regulatory Proposal*.

Depreciation

Depreciation has been calculated on a straight line basis, using asset lives as provided in chapter 21 of this *Regulatory Proposal*.

Disposals

Forecast asset disposals have been incorporated.

Inflation rate

An inflation rate has been assumed, which is consistent with the rate used for the WACC.

19.5.3. Amendments to the RAB value for other control services

Clause 6.5.1(a) of the *Rules* requires that the RAB is the value of those assets that are used by Aurora for the provision of *Standard Control Services*, but only to the extent that they are used to provide such services.

In setting the asset value as part of the 2007 Pricing Determination OTTER has allocated distribution assets, excepting metering and roadlighting assets, as prescribed distribution services, meaning that certain prescribed assets may be used to provide other services only in forthcoming *Regulatory Control Periods*.

Consistent with the requirements of clause 6.5.1(a) the adjusted RAB value will also require an adjustment for those OTTER prescribed service classification assets that will be treated as other services during the forthcoming *Regulatory Control Period*.

In assessing the difference in service classifications, the methodology applied is to identify those assets within the RAB that will provide other control services and remove their actual value from the RAB.

Where there are shared service assets, such as IT, an adjustment is also made to the RAB. This adjustment is undertaken by deducting an amount determined as the percentage of total spend for the other control services.

These differences have been input into the AER's RFM.

Table 92 summarises Aurora's adjustments to the RAB for other services.

Table 92

RAB – 1 July 2012

	($m)
RFM closing RAB 30 June 2012	1,460.24
Other control services adjustments	12.65
Amended closing RAB	1,447.59
Inflation on amended closing RAB	37.28
Opening RAB 1 July 2012	1,484.86

19.6. 2012-17 RAB

Table 93 summarises Aurora's forecast of the RAB over the 2012-17 *Regulatory Control Period*.

Table 93

RAB – 2012-17

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Opening RAB – 1 July	1,484.86	1,572.70	1,659.18	1,747.16	1,840.51
Forecast capital expenditure	153.39	159.17	158.77	157.52	163.64
Forecast regulatory depreciation	83.33	91.76	90.90	86.19	88.14
Forecast disposals	0.75	1.08	1.69	1.55	1.59
Forecast customer contributions	20.96	21.50	22.06	22.63	23.21
Closing balance	1,533.22	1,617.53	1,703.30	1,794.31	1,891.21
Forecast inflation rate	2.58%	2.58%	2.58%	2.58%	2.58%

20. Return on Capital

20. Return on Capital

20. Return on capital

20.1. NEL requirements

The National Electricity Objective set out within the NEL at section 7 is:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

The revenue and pricing principles at section 7A(5) further state that:

A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

Section 16 2(a)(i) of the NEL requires that the AER must, when exercising a discretion in making those parts of a Distribution Determination relating to direct control network services take into account the revenue and pricing principles.

20.2. Rules requirements

Clause 6.4.3 of the *Rules* prescribes that the revenue requirement for Aurora must be determined using a building block approach. The *Rules* require that one of the components of the building block should be a return on capital and further that the return on capital is calculated in accordance with clause 6.5.2.

Clause 6.5.2 requires that the return on capital must be calculated by applying a rate of return for Aurora to the value of the regulatory asset base. The rate of return for Aurora is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Aurora and must be calculated as a nominal post-tax weighted average cost of capital (WACC) in accordance with the following formula:

$$\mathrm{WACC} = k_e \frac{E}{V} + k_d \frac{D}{V}$$

where:

k_e *is the return on equity and is calculated as:*

$$r_f + \beta_e \times MRP$$

where:

r_f *is the nominal risk free rate;*

β_e *is the equity beta; and*

MRP *is the market risk premium.*

k_d *is the return on debt and is calculated as:*

$$r_f + DRP$$

where:

DRP *is the debt risk premium.*

E/V *is the value of equity as a proportion of the value of equity and debt, which is 1 - D/V; and*

D/V *is the value of debt as a proportion of the value of equity and debt.*

Clause 6.5.2(c) states that the nominal risk free rate is (unless some different provision is made by a relevant statement of regulatory intent) the rate determined by the AER on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years.

Clause 6.5.2(e) states that the debt risk premium is the premium determined by the AER as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency.

Clause 6.5.4(a) and (d) requires that the AER must carry out reviews of the following matters:

(1) the nominal risk free rate;

(2) the equity beta;

(3) the market risk premium;

(4) the "default" maturity period and bond rates used to calculate the nominal risk free rate;

(5) the ratio of the value of debt to the value of equity and debt;

(6) credit rating levels used to calculate the debt risk premium; and

(7) the assumed utilisation of imputation credits used to calculate the estimated cost of corporate income tax (refer to chapter 22 of this Regulatory Proposal).

Clause 6.5.4(c) requires that the AER must, in consequence of a review, issue a statement (a statement of regulatory intent or SORI) adopting values, methods and credit rating levels for DNSPs or for specified classes of DNSPs.

Clause 6.5.4(f) requires that a SORI adopting a revised value, method, or credit rating level applies only for the purposes of a building block proposal submitted to the AER after publication of the SORI.

Clause 6.5.4(g) requires that a Distribution Determination to which a SORI is applicable must be consistent with the SORI unless there is persuasive evidence justifying a departure, in the particular case, from a value, method or credit rating level set in the SORI.

Clause 6.5.4(h) requires that, in deciding in a Distribution Determination whether a departure from a value, method or credit rating level set in a SORI is justified, the AER must consider:

(1) the criteria on which the value, method or credit rating level was set in the SORI (the underlying criteria); and

(2) whether, in the light of the underlying criteria, a material change in circumstances since the date of the SORI, or any other relevant factor, now makes a value, method or credit rating level set in the SORI inappropriate.

Clause 6.12.1(5) states that a Distribution Determination is predicated on a constituent decision by the AER in relation to the rate of return on whether to apply or depart from a value, method or credit rating level set out in a SORI in accordance with clause 6.5.4.

Clause S6.1.3(9) requires that a Building Block Proposal must at least contain Aurora's calculation of the proposed rate of return, including any departures from the values, methods or credit rating levels set out in the SORI.

20.3. AER's statement of regulatory intent

The AER undertook a review of the cost of capital values, methods and credit rating levels in accordance with clause 6.5.4 of the *Rules* and released its SORI in May 2009.

The SORI confirms the cost of capital values, methods and credit rating levels that will apply to Aurora when the AER makes its final Distribution Determination unless Aurora proposes any departures from those values, methods or credit rating levels.

The values, methods and credit rating levels applicable in the AER's SORI are shown in Table 94.

Table 94

AER's SORI values

WACC parameter	AER's SORI Value
Risk free rate	Annualised yield on 10 year Commonwealth Government bonds based on an agreed averaging period.
Equity beta	0.80
Market risk premium	6.50%
Value of debt as proportion of value of debt and equity	0.60
Debt risk premium	To be based on a credit rating level of BBB+, specified in clause 6.2.5(e) of the *Rules*.
Value of imputation credits	0.65

20.4. Aurora's proposal

Aurora's proposal for its return on capital addresses the relevant provisions of the NEL, the *Rules* and the SORI issued in May 2009 ("the applicable SORI").

In setting out its proposal, Aurora notes that the provision of an adequate return on capital is of critical importance to Aurora's owners and its customers. In particular, regulatory decision-making that results in the provision of an inadequate post-tax return will damage incentives for investment, and will ultimately deny customers the economic benefits that flow from distribution network investment.

Aurora has prepared a detailed analysis of the cost of capital requirements and its proposals for the values, methods and credit rating levels that will apply to Aurora. This analysis is appended as a confidential attachment to this *Regulatory Proposal*.

20.4.1. Risk free rate

The SORI requires that:

- the nominal risk free rate be calculated on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years (based on the indicative mid rates published by the Reserve Bank of Australia); and
- the period of time in which the nominal risk free rate is to be calculated should be as close as practically possible to the commencement of the regulatory control period, and should initially be proposed by the DNSP and agreed by the AER.

Aurora has set out the measurement period of the nominal risk free rate that it proposes to be adopted for the purpose of the AER's final determination in an attachment appended to this *Regulatory Proposal*. In accordance with clause 6.5.2(c)(2)(iii) of the *Rules*, Aurora requests that this information remain confidential.

The risk free rate proposed in this *Regulatory Proposal* is therefore indicative only and is based on the 20 business day averaging period commencing on 28 February 2011 and ending on 25 March 2011. This rate is proposed to facilitate the calculation of the proposed rate of return at the time of submitting this *Regulatory Proposal*.

The risk free rate for this *Regulatory Proposal*, estimated in the manner described above, is 5.53 percent.

20.4.2. Debt risk premium

Aurora's debt risk premium methodology follows a three step process:

step 1: establish a reliable and robust fair value curve as the starting point for deriving the debt risk premium;

step 2: select a methodology to extrapolate the debt risk premium to a term of 10 years; and

step 3: compare the estimated debt risk premium with the yields from the current bond market.

Aurora proposes to estimate the debt risk premium by commencing with the debt risk premium that is obtained from the longest term to maturity (but not greater than 10 years) for which the Bloomberg BBB band fair value curve is produced (which is currently 7 years), and then to extrapolate this debt risk premium to one that is consistent with a 10 year term to maturity.

Aurora has set out the measurement period of the debt risk premium that it proposes to be adopted for the purpose of the AER's final determination in an attachment appended to this Regulatory Proposal. Consistently with clause 6.5.2(c)(2)(iii) of the Rules, Aurora requests that this information remain confidential.

The debt risk premium proposed in this *Regulatory Proposal* is therefore indicative only and is based on the 20 business day averaging period commencing on 28 February 2011 and ending on 25 March 2011. This rate is proposed to facilitate the calculation of the proposed rate of return at the time of submitting this Regulatory Proposal.

Aurora's final debt risk premium will be determined during an averaging period that is closer to the time of the AER's final decision.

It is noted that the limited trade in Australian corporate bonds, the small number of number of bonds on issue and the limited quantity of new bond issues (especially around the 10 year mark) continue to create a challenge for estimating the debt risk premium. However, conditions in the Australian corporate bond market are expected to continue to improve. Importantly, as the quality of the market evidence improves, it is automatically factored into the debt risk premium that is derived by applying Aurora's proposed method.

Applying this method to the 20 business days from 28 February 2011 to 25 March 2011 has delivered a debt risk premium of 454 basis points. Aurora has also tested this estimate against the debt risk premium for the available bonds on issue (including bonds of close credit ratings and floating as well as fixed rate instruments) and concluded that this estimate is reasonable on the basis of the current evidence.

20.4.3. Gearing level

The SORI requires that the value of debt as a proportion of the value of debt and equity (D/V or "gearing") be set at 0.60.

Aurora proposes to adopt a value of 0.60 for the gearing level, consistent with the SORI.

20.4.4. Market risk premium

The SORI requires that the value of the market risk premium be set at 6.50 percent.

Aurora proposes to adopt a value of 6.50 percent for the market risk premium, consistent with the SORI.

20.4.5. Value of imputation credits

In the AER's cost of capital review, the value of imputation credits (denoted by g or gamma) was determined as the product of two underlying parameters:

- the rate at which imputation credits are distributed to investors ("distribution ratio", also represented by F); and
- the rate at which distributed credits are redeemed by investors ("utilisation rate", also represented by q or theta).

The AER's cost of capital review decision adopted a value of 100 per cent for the distribution rate and 0.65 for the utilisation rate. Based on these values, the SORI requires that a value of 0.65 be adopted in relation to the assumed value of imputation credits.

The Australian Competition Tribunal's review of the AER's decision on the value of gamma

The Australian Competition Tribunal's (the Tribunal) recent decision on the value of gamma was issued in response to an application by Energex, Ergon and ETSA Utilities (the applicants) for a review of the AER's final decisions on their respective distribution revenues for the 2011-2015 *Regulatory Control Period*.

In these proceedings, the Tribunal found that the AER had erred in its treatment of both the distribution ratio and the utilisation rate, which underpin the calculation of gamma.

In relation to the distribution ratio, the AER acknowledged it made an error of fact in its cost of capital review in interpreting the distribution ratio of 71 percent, as derived by Hathaway and Officer (2004)[1], as a long-term distribution ratio. On this basis, the AER conceded there was evidence to justify departure from the value of gamma adopted in its SORI, insofar as it relates to the distribution ratio. The AER did not however concede that the appropriate substitute value for the distribution ratio was necessarily 70 percent, as proposed by the applicants in this case. However, in its decision of December 2010, the Tribunal determined that the most appropriate distribution ratio for gamma was 0.70.[2]

1 Hathaway N. and Officer B., *The value of* imputation *credits – update 2004*, (November 2004).

2 Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9, paragraph 4.

In relation to the utilisation rate, the Tribunal ruled that the value of theta should be 0.35. However, the Tribunal also notes that this decision was based on the material before it and that the estimation of gamma is "an ongoing intellectual and empirical endeavour".

Given the uncertainty that still surrounds this matter and the timing of the Tribunal decision, Aurora has utilised the AER's preferred value of 0.65 for theta for the purposes of this *Regulatory Proposal*.

Applying the Tribunal's value of the distribution ratio of 0.70 and the AER's preferred value for theta of 0.65, produces a (rounded) value for gamma of 0.45. Aurora has adopted 0.45 as the value for imputation credits for the purposes of this *Regulatory Proposal*.

Aurora will however utilise the Tribunal's theta value of 0.35 in its revised *Regulatory Proposal*. When applied to the Tribunal's value of the distribution ratio of 0.70 this produces a (rounded) value for gamma of 0.25.

20.4.6. Equity beta

The equity beta has been assigned a value of 0.80 in the SORI.

Aurora accepts that the appropriate value for the equity beta is difficult to estimate from a statistical standpoint and notes that the AER's decision in the cost of capital review to reduce the value of the equity beta from the previously adopted value of 1.00 remains highly contentious. Nevertheless, Aurora proposes to adopt a value of 0.80 for the equity beta, consistent with the requirements of the SORI.

20.4.7. Inflation

Aurora proposes to adopt an inflation forecast of 2.575 percent per annum for this *Regulatory Proposal*.[3] The forecast inflation is the geometric average of the forecast annual inflation for each of the ten years from 2011 to 2020, as shown in Table 95.

For the 2011 and 2012 years, the expected inflation estimates are consistent with the data on median inflation expectations for market economists as reported in the Reserve Bank of Australia's ("RBA") February 2011 Statement of Monetary Policy[4].

For the 2013 year and beyond, the expected inflation estimates are the midpoints of the RBA's long term inflation target range of 2 per cent to 3 per cent (i.e. 2.50 percent).

Aurora understands that this approach is consistent with the AER's preferred approach for estimating the forecast inflation rate.

Table 95

Forecast inflation (percent per annum, June year end)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Inflation forecast	2.50	2.75	3.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Geometric average	2.575									

20.4.8. Aurora's parameters

The values, methods and credit rating levels proposed by Aurora for the cost of capital are shown in Table 96.

Table 96

Aurora proposal

Parameter	AER's SORI value	Aurora proposal
Nominal risk free rate	Annualised yield on 10 year Commonwealth Government bonds based on an agreed averaging period.	5.53%
Equity beta	0.80	0.80
Market risk premium	6.50%	6.50%
Value of debt as a proportion of the value of debt and equity (gearing)	0.60	0.60
Debt risk premium	To be based on a credit rating level of BBB+, specified in clause 6.2.5(e) of the *Rules*.	4.54%
Value of imputation credits	0.65	0.45
Inflation		2.58%
Cost of equity (ke)		10.73%
Cost of debt (kd)		10.07%
Nominal vanilla WACC		10.33%
Post-tax nominal WACC		7.83%

3 Aurora understands that this estimate will be updated during the AER's determination process as data becomes available.

4 Reserve Bank of Australia, Statement on Monetary Policy, February 2011, Table 6.1, page 60.

21. Depreciation

21. Depreciation

21.1. Rules requirements

Clause 6.4.3 of the *Rules* provides that the annual revenue requirement must be determined using a building block approach, which includes a component for depreciation calculated pursuant to clause 6.5.5.

Clause 6.5.5(a)(1) states that depreciation must be calculated based on the value of the RAB at the beginning of each year.

Clause 6.5.5 (a)(2) states that depreciation is to be calculated using depreciation schedules nominated by Aurora in the Building Block Proposal.

Clause 6.5.5(b)(1) requires that depreciation schedules must be based on the economic life of the assets.

Clause 6.5.5 (b)(2) requires that the recovery of depreciation must maintain net present value neutrality over the life of the asset.

Clause 6.5.5(b)(3) requires that the economic life, depreciation rates and methods underpinning the calculation of depreciation for a *Regulatory Control Period* must be consistent that specified for that period in the previous Distribution Determination.

Clause S6.1.3(12) requires the depreciation schedules nominated by Aurora to be categorised by asset class or category driver, together with details of the amounts, values and other inputs used to compile the depreciation schedules, and a demonstration that the depreciation schedules conform with the requirements set out in clause 6.5.5(b) of the *Rules*.

21.2. Depreciation methodology

The *Rules* do not set out a precise mechanism for calculating depreciation. The AER has however issued its preferred methodology in the PTRM. Aurora has used the AER's PTRM without amendment, and has therefore calculated its depreciation allowance using that methodology.

Aurora has depreciated new assets according to standard lives for each asset class. These are set out in the Table 97.

Aurora has depreciated its existing assets over their remaining asset lives. Opening asset values at 1 July 2012 have been calculated applying the AER's RFM. Details on how Aurora has undertaken this process are set out in chapter 19 of this *Regulatory Proposal*.

21.3. Standard and remaining lives for asset classes

Aurora has adopted standard and remaining asset lives in accordance with good engineering practice and its own financial records.

Opening remaining asset lives for 1 July 2012 are calculated using the AER's RFM and are an input to the PTRM. These are calculated values. Aurora's methodology for establishing the opening asset lives at the commencement of the previous *Regulatory Control Period* is set out in chapter 19 of this *Regulatory Proposal*.

Aurora's proposed standard asset lives by asset class have been derived from Aurora's ring-fenced accounts.

Table 97 provides standard and remaining asset lives by asset class.

Table 97

Standard and remaining lives

Asset category	Standard life (years)	Remaining life (years)
Overhead subtransmission lines (urban)	50	31.65
Underground subtransmission lines (urban)	60	38.68
Urban zone substations	40	31.49
Rural zone substations	40	30.92
SCADA	10	2.86
Distribution switching stations (ground)	40	33.01
Overhead high voltage lines urban	35	24.12
Overhead high voltage lines rural	35	20.84
Voltage regulators on distribution feeders	40	23.23
Underground high voltage lines	60	42.22
Underground high voltage lines SWER	60	51.23
Distribution substations HV (pole)	40	33.29
Distribution substations HV (ground)	40	17.07
Distribution substations LV (pole)	40	23.01
Distribution substations LV (ground)	40	24.58
Overhead low voltage lines underbuilt urban	35	23.73
Overhead low voltage lines underbuilt rural	35	17.74
Overhead low voltage lines urban	35	23.95
Overhead low voltage lines rural	35	25.96
Underground low voltage lines	60	38.11
Underground low voltage common trench	60	47.20
HVST service connections	40	2.08
HV service connections	40	28.41
HV metering CA service connections	40	11.07
HV/LV service connections	40	27.30
Business LV service connections	35	13.26
Business LV metering CA service connections	25	6.33
Domestic LV service connections	35	22.11
Domestic LV metering CA service connections	20	4.00
Emergency network spares	1	0.00
Motor vehicles	6	3.50
Minor assets	5	2.67
Non-system property	40	20.93
Spare parts	1	0.00
NEM assets	5	2.07

21.4. Forecast regulatory depreciation

Table 98 shows the depreciation Building Blocks for *Standard Control Services* for 2012-17:

Table 98

Depreciation building blocks

	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Straight-line depreciation (real)	81.24	87.21	84.23	77.86	77.62
Straight-line depreciation (nominal)	83.33	91.76	90.90	86.19	88.14
Regulatory depreciation (nominal)	46.05	52.28	49.25	42.33	41.93
Inflation on opening RAB	2.58%	2.58%	2.58%	2.58%	2.58%

21.5. Regulatory tax lives for asset classes

Aurora's opening tax asset values, and opening tax asset lives in the AER's RFM are set out in chapter 22 of this *Regulatory Proposal*.

In relation to the 2012-17 *Regulatory Control Period*, Aurora has forecast its cost of corporate income tax pursuant to clause 6.5.3 of the *Rules*, using the PTRM in accordance with the AER's preferred methods. Aurora has calculated tax depreciation in accordance with tax law and with the methodology contained within the PTRM. In accordance with the PTRM, Aurora has calculated tax depreciation on a straight line basis, using applicable straight line tax depreciation rates.

Table 99 provides tax asset lives by asset class.

Table 99

Tax lives

Asset category	Tax life (years)	Remaining life (years)
Overhead subtransmission lines (urban)	45	40.17
Underground subtransmission lines (urban)	50	48.32
Urban zone substations	33	28.75
Rural zone substations	33	30.98
SCADA	33	29.28
Distribution switching stations (ground)	36	28.99
Overhead high voltage lines urban	35	29.16
Overhead high voltage lines rural	33	24.66
Voltage regulators on distribution feeders	45	43.60
Underground high voltage lines	31	18.97
Underground high voltage lines SWER	31	30.37
Distribution substations HV (pole)	38	32.97
Distribution substations HV (ground)	33	25.42
Distribution substations LV (pole)	37	31.86
Distribution substations LV (ground)	34	28.74
Overhead low voltage lines underbuilt urban	37	31.29
Overhead low voltage lines underbuilt rural	39	34.54
Overhead low voltage lines urban	35	28.58
Overhead low voltage lines rural	37	30.86
Underground low voltage lines	42	39.47
Underground low voltage common trench	43	40.92
HVST service connections	36	0.00
HV service connections	36	31.44
HV metering CA service connections	36	34.96
HV/LV service connections	36	31.52
Business LV service connections	36	31.16
Business LV metering CA service connections	36	34.89
Domestic LV service connections	36	31.90
Domestic LV metering CA service connections	36	34.66
Emergency network spares	1	0.00
Motor vehicles	9	4.40
Minor assets	5	2.92
Non-system property	35	22.78
Spare parts	1	0.00
NEM assets	3	1.60

21.6. Forecast regulatory tax depreciation

Aurora's forecast tax depreciation schedule for the 2012-2017 *Regulatory Control Period*, which has been used to calculate Aurora's nominal allowance for corporate income tax, is shown in Table 100. Chapter 22 of this *Regulatory Proposal* provides further details on Aurora's proposed allowance for corporate income tax

Table 100

Tax depreciation schedule

Asset category	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Overhead subtransmission lines (urban)	0.2	0.2	0.2	0.2	0.2
Underground subtransmission lines (urban)	0.1	0.1	0.1	0.1	0.1
Urban zone substations	1.2	1.3	1.4	1.6	1.8
Rural zone substations	0.1	0.1	0.1	0.1	0.1
SCADA	0.2	0.2	0.4	0.6	0.6
Distribution switching stations (ground)	0.9	1.0	1.0	1.0	1.1
Overhead high voltage lines urban	3.1	3.3	3.5	3.7	3.9
Overhead high voltage lines rural	10.0	10.9	11.9	12.8	13.7
Voltage regulators on distribution feeders	0.1	0.1	0.1	0.1	0.2
Underground high voltage lines	6.9	7.6	8.3	9.0	9.7
Underground high voltage lines SWER	0.0	0.0	0.0	0.0	0.0
Distribution substations HV (pole)	0.0	0.0	0.0	0.0	0.0
Distribution substations HV (ground)	0.3	0.4	0.5	0.7	0.8
Distribution substations LV (pole)	2.4	2.7	3.0	3.4	3.7
Distribution substations LV (ground)	1.3	1.5	1.6	1.8	2.0
Overhead low voltage lines underbuilt urban	1.3	1.4	1.5	1.6	1.6
Overhead low voltage lines underbuilt rural	0.5	0.6	0.7	0.8	0.9
Overhead low voltage lines urban	1.6	1.7	1.8	1.9	2.1
Overhead low voltage lines rural	1.4	1.7	1.9	2.1	2.3
Underground low voltage lines	0.8	1.0	1.1	1.3	1.5
Underground low voltage common trench	0.5	0.6	0.7	0.8	0.9
HVST service connections	-	-	-	-	-
HV service connections	0.0	0.0	0.0	0.0	0.0
HV metering CA service connections	0.0	0.0	0.0	0.0	0.0
HV/LV service connections	0.0	0.1	0.1	0.1	0.1
Business LV service connections	0.1	0.1	0.2	0.2	0.2
Business LV metering CA service connections	0.1	0.1	0.1	0.2	0.2
Domestic LV service connections	1.3	1.4	1.6	1.7	1.9
Domestic LV metering CA service connections	0.1	0.1	0.1	0.1	0.2
Emergency network spares	-	-	-	-	-
Motor vehicles	5.5	6.2	6.9	7.3	4.3
Minor assets	10.1	12.3	13.2	5.5	8.1
Non-system property	1.4	1.5	1.5	1.5	1.5
Spare parts	-	-	-	-	-
NEM assets	5.3	3.2	-	-	-
Residual tax value	1,105.8	1,197.1	1,285.1	1,375.3	1,467.9

21.7. Actual or forecast depreciation

Clause 6.12.1(18) of the Rules requires the AER to make a decision as to whether depreciation for establishing the RAB as at the commencement of the forthcoming *Regulatory Control Period* is to be based on actual or forecast capital expenditure.

Aurora proposes that depreciation for establishing the RAB as at the commencement of the 2012-17 *Regulatory Control Period* be based on its:

- actual capital expenditure for the period 2006-07 to 2009-10; and
- forecast capital expenditure for the period 2010-11 and 2011-12.

22. Corporate Income Tax

22. Corporate income tax

22.1. Rules requirements

Clause 6.4.3(a) of the *Rules* requires that Aurora's annual revenue requirement for each *Regulatory Year* of the 2012-17 *Regulatory Control Period* must be determined using a building block approach, under which one of the building blocks is the estimated cost of corporate income tax of Aurora for that year.

Clause 6.4.3(b)(4) specifies that the estimated cost of corporate income tax is determined in accordance with clause 6.5.3 (below); and notes that a SORI may be relevant to the calculation (clause 6.5.4).

Clause 6.5.3 requires that the estimated cost of Aurora's corporate income tax for each *Regulatory Year* (ETC_t) must be calculated in accordance with the following formula:

$$ETC_t = (ETI_t \times r_t)\,(1 - \gamma)$$

where:

ETI_t *is an estimate of the taxable income for that Regulatory Year that would be earned by a benchmark efficient entity as a result of the provision of Standard Control Services if such an entity, rather than Aurora, operated the business of Aurora, such estimate being determined in accordance with the PTRM;*

r_t *is the expected statutory income tax rate for that Regulatory Year as determined by the AER; and*

γ *is the assumed utilisation of imputation credits.*

For these purposes:

- *the cost of debt must be based on that of a benchmark efficient Distribution Network Service Provider (DNSP); and*
- *the estimate must take into account the estimated depreciation for that Regulatory Year for tax purposes, for a benchmark efficient DNSP, of assets where the value of those assets is included in the regulatory asset base for the relevant distribution system for that Regulatory Year.*

Clause 6.5.4(d)(7) provides that the AER may review the value of the assumed utilisation of imputation credits referred to in clause 6.5.3 and issue a SORI setting out this value (and other values). The AER determined that the value of imputation credits, or gamma should be 0.65 in the SORI relevant to Aurora's distribution building block Determinations[1]. A departure from the SORI is only permissible where there is persuasive evidence to justify that departure.

Section 2.5 of the RFM Handbook details how Aurora's opening tax value for the final *Regulatory Year* of the previous *Regulatory Control Period* should be used to establish the nominal opening tax value for each *Regulatory Year* of the current *Regulatory Control Period*.

Section 2.1 of the PTRM Handbook sets out how the opening tax value for each asset class must be determined on the basis of closing tax asset values for the current *Regulatory Control Period*, and how the tax remaining life and tax standard life should be recorded.

Consistent with the above *Rules* requirements this chapter sets out the methodology used by Aurora to determine the estimated cost of corporate income tax; and summarises the estimated tax costs. Importantly, the corporate income tax allowance is based on estimates of the tax paid by a "benchmark efficient DNSP", not on the tax actually paid, or forecast to be actually paid.

1 AER Statement of regulatory intent on the revised WACC parameters (distribution), May 2009, page 7.

22.2. OTTER treatment of corporate income tax

OTTER applied a pre-tax real approach to determine Aurora's revenue requirements for the 2008-12 *Regulatory Control Period*[2] which meant that it did not establish a tax asset base for Aurora. This was because there was no requirement to specifically provide an allowance for corporate income tax.

Previously OTTER was required only to make a broader assessment of tax implications by having regard for "*the impact on pricing policies of any borrowing, capital, dividend and taxation or tax equivalent obligations of the electricity entity, including obligations to renew or increase assets*"[3]. Accordingly OTTER allowed a return on capital that was sufficient to cover estimated corporate income tax payments over the *Regulatory Control Period*.

Aurora is registered under the National Tax Equivalent Regime (NTER) which requires the lodgement of an income tax equivalent return for each year. Under the NTER the relevant tax laws are applied notionally to Aurora as if it were the subject of the laws. Aurora's income tax equivalent liability is assessed annually by the Australian Taxation Office (ATO), and it must pay quarterly instalments of the liability to the Department of Treasury and Finance on the basis of this assessment.

Table 101 summarises Aurora's NTER values for *Standard Control Services* through to the period ending 2009-10, as assessed by the ATO.

22.3. 2012-17 Regulatory Control Period overview

Aurora has calculated its corporate income tax allowance for each Regulatory Year of the 2012-17 *Regulatory Control Period* consistent with the requirements of the *Rules*, and RFM and PTRM Handbooks. For this purpose, Aurora has adopted the following high level approach, where it:

(1) established the appropriate asset balances for its opening tax asset base as of 1 July 2007 using the methodology devised and endorsed by Deloitte and KPMG respectively. A total opening tax asset base of $526.1 million was calculated;

(2) entered the opening tax asset base values and required data, as of 1 July 2007, into the AER's RFM, to determine the closing tax asset base of $1,028.5 million as at 30 June 2012;

(3) adjusted the closing tax asset base value to account for the use of shared services assets to determine the closing tax asset base as at 30 June 2012, which then was input into the PTRM as the 1 July 2012 opening tax asset base of $1,015.3 million;

(4) calculated its tax income as the estimated ARR of $1,537.0 million, plus the estimated value of customer contributions of $106.4 million, using the PTRM;

(5) calculated its estimated tax expense of $1,187.5 million based on the costs that a "benchmark efficient entity" would incur under the current statutory corporate tax rate as prescribed by ATO taxation rules. Tax expenses included were the estimated values for operating expenditure, tax depreciation, and interest or debt servicing expenses;

(6) calculated pre-tax income of $455.9 million, being its total tax income less total tax expenses, as determined in the steps above;

(7) recorded a carried forward tax loss equal to zero as at 1 July 2012;

(8) aggregated the values determined in steps (4) and (5) to obtain the value for total taxable income of $455.9 million;

(9) applied the current statutory corporate tax rate of 30 percent, as prescribed by ATO taxation rules to its total taxable income to determine the tax allowance building block; and

(10) adjusted the corporate income tax allowance to offset for imputation credits. A gamma value of 0.45 was applied, reflecting a departure from the value of 0.65 set out in the AER's SORI.

The specific issues encountered, and the rationale underpinning Aurora's approach, in undertaking this process and associated calculations are discussed below.

Aurora's opening tax asset base as of 1 July 2007 was calculated to be $526.1 million; and its opening tax asset base as of 1 July 2012 was estimated to be $1,015.3 million. Aurora's corporate income tax cost estimate for the 2012-17 *Regulatory Control Period* is set out in Table 102.

2 OTTER 2007 Electricity Pricing Investigation – Final Report, p. XIX, 2007. .

3 Tasmanian Electricity Supply Industry (Price Control) Regulations 2003, s33(2)(j).

Table 101

NTER Values for Standard Control Services to 2009-10

	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	2007-08 ($m)	2008-09 ($m)	2009-10 ($m)
Total NTER Opening Asset Value	288.691	336.150	394.778	472.209	526.090	607.636	705.730
Disposals	1.245	1.073	1.395	7.532	0.524	0.971	1.120
Tax Depreciation	21.157	23.883	29.782	31.606	29.407	35.926	38.894
Actual Capital expenditure	69.861	83.585	108.608	93.021	111.475	134.990	148.603
Total NTER Closing Asset Value	**336.150**	**394.778**	**472.209**	**526.090**	**607.636**	**705.730**	**814.318**

Table 102

Corporate income tax estimate for 2012-17 Regulatory Control Period

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)	TOTAL ($m)
Tax payable	25.76	27.92	27.48	27.68	27.92	136.77
Less value of imputation credits	11.59	12.56	12.37	12.46	12.57	61.55
Net corporate income tax allowance	14.17	15.36	15.12	15.22	15.36	75.22

22.4. Opening tax asset base

The establishment of the opening tax asset base forms the foundation step in calculating Aurora's corporate income tax allowance. As OTTER applied a pre-tax real approach to determine Aurora's revenue requirements for the current *Regulatory Control Period*, Aurora has not previously been required to establish a tax asset base. As a result, it has been necessary for Aurora to develop, on the basis of available data, a methodology to establish the opening tax asset base for input into the RFM and the PTRM.

Aurora engaged the services of Deloitte to develop, and KPMG to endorse, the methodology it has used to establish the opening tax asset base as at 1 July 2007. In developing its methodology Deloitte had regard to its understanding of the AER's ideal approach[4], being to:

- identify when the entity was first subject to the tax equivalence regime;
- verify the tax value of the assets as at that date;
- identify a historical profile of when assets first became subject to tax;
- calculate a tax roll-forward to the commencement of the regulatory period using tax depreciation and actual capital expenditure and disposals; and
- depreciate on a straight line basis for tax purposes.

Aurora proposes an opening tax asset base as at 1 July 2007 of $526.1 million as determined using the below methodology.

22.4.1. Fixed asset registers

Consistent with the approach developed by Deloitte[5], Aurora adopted a methodology which sourced asset data from two fixed asset registers, dependent on when the assets were acquired, being:

- tax fixed asset register for assets acquired up to 30 June 2002; and
- accounting fixed asset register for assets acquired between 1 July 2002 and 30 June 2007.

Aurora used its tax written down values as at 30 June 2002 in order to provide consistency between how Aurora actually depreciates assets for tax purposes under the NTER, with the method to account for tax depreciation under the RFM and PTRM models in terms of the measurement of the effective lives of Aurora's assets.

4 Deloitte, Aurora Energy Pty Ltd, Australian Energy Regulator, 24 November 2010, section 1.1.

5 Ibid. section 1.3.

It was necessary that Aurora use values from the accounting fixed asset register for the period 1 July 2002 to 30 June 2007, rather than the tax fixed asset register, for several reasons:

- in the tax fixed asset register, low value assets are pooled under concessional accelerated depreciation rules consistent with Division 40 of the *Income Tax Assessment Act 1997* (ITAA);
- in the accounting fixed asset register, assets are not pooled which enables all additions in the period to be separately identified and depreciated using specific straight line depreciation rates; and
- the tax pooled assets include *Alternative Control Services* assets, being street lights and meters, which can only be separately identified and excluded using the accounting fixed asset register.

Aurora notes that the effective lives associated with the accounting fixed asset register are determined using the same principles as for the tax fixed asset register.

For assets acquired up to 30 June 2002 Aurora's tax fixed asset register supplied the data pertaining to asset acquisition costs; depreciation start dates; and straight line depreciation rates and associated effective asset lives. Where information on depreciation rates and effective asset lives was not available values used for the equivalent depreciation rate for an asset with the same effective life were used as a proxy for the actual data.

For assets acquired in the period 1 July 2002 to 30 June 2007 Aurora's accounting fixed asset register supplied asset acquisition costs; depreciation start dates; and straight line depreciation rates and associated effective asset lives.

Aurora notes in relation to its tax fixed asset register, used up until 30 June 2002, that the acquisition values included low value tax pooled assets. It is acknowledged that the pooled assets potentially include alternative control assets; however these do not impact on Aurora's tax asset base model. This is because these assets are written off under Aurora's model prior to 30 June 2007, and are consequently not included in the 30 June 2007 values under the tax asset base model.

The remainder of assets that would have fallen within the low value pool, such as tools, computer and communications equipment, were considered to have short effective lives, meaning that they would have had little, if not a nil, written down value as at 30 June 2007, regardless of whether separate effective lives were determined and used for these assets. On this basis, Aurora considered its approach of using the tax, then accounting fixed asset register data, as appropriate and consistent with *Rules* requirements.

22.4.2. Segregation of Standard Control Services assets

Aurora removed fully depreciated assets; land assets not eligible for depreciation deductions; and low value tax pooled assets from its tax asset base model. Where separately coded, and therefore identifiable, non-*Standard Control Services* assets were also removed from the tax asset base model, and this included the removal of:

- the portion of shared assets that could not be attributed to *Standard Control Services*;
- *Alternative Control Services* assets, where separately recorded as meters or streetlights;
- Meter Data Management System (MDMS) assets; and
- Aurora Retail assets.

22.4.3. NTER

Aurora, as a Government-owned business, is not subject to the ITAA for Constitutional reasons, but must pay income tax under the NTER for competition neutrality reasons. It is noted that Aurora's methodology to establish the opening tax asset base is also consistent with NTER requirements.

Where an entity was under a state Tax Equivalent Regime (TER), and commenced being under the NTER prior to 30 June 2002, the NTER entity's commencing position for the purposes of the NTER was required to be equal to its closing positions in the TER[6]. In this respect, the Hydro-Electric Corporation commenced under the State TER in 1990. Whilst Aurora was also initially under the State TER, a transfer of assets at written down values is in line with the subsequent NTER requirements.

Where there is a transfer of assets from one NTER entity to another under a Government imposed restructure, the restructure should be treated in a tax neutral manner for NTER purposes[7]. A tax neutral manner suggests that assets are transferred at tax written down values, meaning there is no gain or loss, or step up or down of cost base, from the transfer of depreciable assets from one NTER entity to another. Aurora confirms that its approach has been consistent with NTER requirements in this regard.

22.4.4. Depreciation

Aurora considers its method of depreciation to be appropriate with the requirements of the *Rules* on the basis that it:

- applies straight-line depreciation;
- is consistent with the effective lives of assets as used for NTER tax depreciation purposes;
- depreciates assets from the time the assets were acquired as per Aurora's historic records; and
- uses effective lives consistent with accounting fixed asset register effective lives.

It should be noted that there is a differential between the written down values of Aurora's model and those of the tax fixed asset register, which included assets that were subject to accelerated depreciation provisions of the ITAA. This is consistent with requirements of the RFM and PTRM, where the straight-line method of depreciation has been used for the period from 1 July 2002 to 30 June 2007.

To determine straight-line depreciation rates Aurora has in the past calculated tax depreciation using self-assessed effective lives based on the effective lives assessed for accounting depreciation purposes. In its tax asset base model Aurora determined the straight-line depreciation rate by using the effective life stated for each asset in its registers.

Where there was no statement of the effective life or the prime cost rate for the assets, the rate was determined using the diminishing value rate of depreciation used in the tax fixed asset register. This is only relevant for assets acquired up to 30 June 2002.

22.4.5. Effective lives

Aurora did not consider it appropriate to use effective lives, as published by the ATO, and accepted by the Commissioner of Tax, in determining the straight line depreciation rate for its assets. This is because Aurora's asset base is characterised by a large number and variety of depreciable assets and it is difficult to apply the Commissioner's rates to each individual asset.

Although effective lives could be allocated based on asset categories to accommodate the Commissioner's rates, this approach would have been less precise than the self assessed lives allocated by Aurora, which were determined on an asset-by-asset basis. For this reason, it is considered that using Aurora's self-assessed effective lives provides a more accurate basis for determining the effective lives of assets, given they were determined upon the initial entry of each individual asset into the fixed asset register.

22.4.6. Work in progress

This *Regulatory Proposal* reflects the forecast work in progress at 30 June 2012 based on currently available data and will be updated in the revised *Regulatory Proposal* for the actual work in progress balance at 30 June 2011. To accommodate the depreciation of work in progress the estimated work in progress value at 1 July 2012 will be calculated on the basis of the work in progress balance at 30 June 2011, which will be known at the time of submitting Aurora's revised *Regulatory Proposal*.

6 ATO Manual for the National Tax Equivalent Regime January 2008 (Version 6), s91.
7 Ibid. s103.

22.4.7. Determination of acquisition costs

Limited historical information was available to enable the written down cost base of the tax assets to be determined. An examination of Aurora's current and historical records carried out by Deloitte determined that the most complete and reliable information was the tax fixed asset register as at 30 June 2002, supplemented by additions and disposals as per the accounting fixed asset register for each of the years ended 30 June 2003 to 30 June 2007 inclusive.

Aurora could only use historical asset data back to 2002 as a result of its migration to a new accounting system and the transfer of all asset values to a new tax fixed asset register. That information was revised for incorporation into the new accounting system, and consequently the historical data prior to 2002 could not be extracted for preparing this *Regulatory Proposal*.

Broadly, to determine the original cost of assets, the following methodology, as developed by Deloitte, was applied:

- for assets acquired up to the period ended 30 June 2002, acquisition cost of assets as stated in Aurora's tax fixed asset register at 30 June 2002 were sourced;
- for assets acquired in the period from 1 July 2002 to 30 June 2007, acquisition costs of assets as per Aurora's accounting fixed asset register were sourced;
- disposals in the period from 1 July 2002 to 30 June 2007 were allocated to each individual asset, using the fixed asset numbers (whether acquired pre or post 30 June 2002). In some cases, the disposal amount was greater than the asset value, or related to assets no longer appearing on the asset register. These surplus amounts were treated as a gain on disposal and excluded from the tax asset base model;
- shared use assets were included in the assets listed as *Standard Control Services* assets and were separately identified according to asset class code. This percentage was then applied to the acquisition cost of *Standard Control Services* assets to reduce the starting value of assets;
- *Alternative Control Services* assets, MDMS assets, and Aurora Retail assets, where separately identified, were removed from the tax asset base model; and
- fully depreciated assets, including low value tax pooled assets, and land assets that are not entitled to depreciation deductions were removed from the model.

22.4.8. Determination of straight-line depreciation rates

In its tax asset base model Aurora determined the depreciation rate by using the effective life stated for each asset in either the tax fixed asset register at 30 June 2002 or the accounting fixed asset register. Each effective life was stated in years with the straight-line depreciation rate being determined by dividing 100 percent by the effective life.

Where there was no statement of the effective life or the straight-line depreciation rate for the assets, the rate was determined using the diminishing value rate of depreciation used in the tax fixed asset register. This was only necessary for some assets acquired up to 30 June 2002, with all assets acquired after this date having known effective lives.

To determine the rate in these instances, the diminishing value rate of depreciation was determined by using a gross-up rate of 150 percent up until 9 May 2006. After this date, the gross-up rate of 200 percent could be used. The self-assessed effective lives used by Aurora in the raw data were then determined using the established diminishing value rate. Finally, the straight-line rate of depreciation, based on the Aurora self-assessed effective lives, was then determined.

22.4.9. Determination of 30 June 2007 tax asset values

Aurora's tax asset base model uses the straight-line method for writing down the value of assets, at the rates determined by Aurora's self-assessed effective lives for each asset, or where not available, using the conversion of diminishing value rates of depreciation to straight-line rates.

The assets were depreciated from the depreciation start date provided in the raw data, which therefore included start dates in the 1950s and sometimes earlier. Accordingly, many of the assets under this methodology were fully written down as at 30 June 2002, and were removed from the tax asset base model.

The raw data sourced acquisition costs of assets, as stated in the tax fixed asset register up until 30 June 2002 (and after that date the accounting cost of additions) rather than written down values given to the assets, were depreciated from the date of acquisition.

From 1 July 2001, assets costing less than $1,000 were pooled and depreciated at 37.5 percent applying the diminishing value method, consistent with the method applied in Aurora's raw data. While the low value asset pooling rules in Division 40 of the ITAA 1997 specify a diminishing value rate of 37.5 percent for low value pools, this rate has been converted to a straight-line depreciation rate to align with the AER's approach.

Although this does not comply with the requirements of the ITAA 1997, which prescribes the diminishing value method, given the use of the same effective life, the rate used is considered appropriate in the circumstances. The 37.5 percent diminishing value converts to an effective life of four years, and a straight-line depreciation rate of 25 percent. Using this rate of 25 percent, these assets would be fully depreciated by 30 June 2007, and so will not affect the value of assets brought into Aurora's model.

Additions from 1 July 2002 to 30 June 2007 have been extracted from the accounting fixed asset register and so do not contain tax pooling as an asset class. In respect of this period, *Alternative Control Services* assets have been excluded based on their fixed asset class codes.

22.5. Imputation credits

Under clause 6.5.4(g) of the *Rules*, Aurora's Distribution Determination may be inconsistent with the values set out by a SORI, but only if there is persuasive evidence to justify a departure. The value of imputation credits, or gamma that is proposed to apply to Aurora is 0.65, as set out in the SORI for *Regulatory Proposals* submitted to the AER between 1 May 2009 and 1 April 2014.

As discussed at section 20.4.5. of this *Regulatory Proposal*, the Australian Competition Tribunal (Tribunal) has recently ruled on the two underlying parameters for gamma: F and theta.

Given the uncertainty that still surrounds this matter and the timing of the Tribunal decision, Aurora has utilised the AER's preferred value of 0.65 for theta for the purposes of this *Regulatory Proposal*.

Applying the Tribunal's value of the distribution ratio of 0.70 and the AER's preferred value for theta of 0.65, produces a (rounded) value for gamma of 0.45. Aurora has adopted 0.45 as the value for imputation credits for the purposes of this *Regulatory Proposal*.

Aurora will however utilise the Tribunal's theta value of 0.35 in its revised *Regulatory Proposal*. When applied to the Tribunal's value of the distribution ratio of 0.70 this produces a (rounded) value for gamma of 0.25.

23. Other Revenue Adjustments

23. Other revenue adjustments

23.1. Overview and Rules requirements

Chapter 6 of the *Rules* requires that any revenue adjustment factors are identified for *Direct Control Services* for each year of the *Regulatory Control Period.* Clauses 6.4.3(a)(6) and 6.4.3(b)(6) of the *Rules* specifically require that the Annual Revenue Requirement for Aurora for each Regulatory Year of a *Regulatory Control Period* must be determined using a building block approach, under which the building blocks include revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous *Regulatory Control Period* which are to be carried forward to that *Regulatory Control Period*. Such increments or decrements are to be apportioned to the relevant year under the Distribution Determination for the relevant *Regulatory Control Period.*

Clause 6.4.3(b)(6) of the *Rules* also specifies the other revenue increments or decrements referred to in paragraph (a)(6) are those that are to be carried forward to the current *Regulatory Control Period* as a result of the application of a control mechanism in the previous *Regulatory Control Period* and are apportioned to the relevant year under the Distribution Determination for the current *Regulatory Control Period.*

This chapter outlines those revenue adjustments that Aurora proposes to submit as part of its annual revenue requirement for *Standard Control Services* for the forthcoming *Regulatory Control Period*. Adjustments related to cost pass throughs are discussed in chapter 27 of this *Regulatory Proposal.*

Aurora's regulatory determination for the current *Regulatory Control Period* prescribes a number of revenue adjustments and pass through events for expenditure that could not be reasonably forecast at the time of making the determination. Aurora proposes that provision for these revenue adjustments is carried forward under the Distribution Determination for the forthcoming *Regulatory Control Period.*

Aurora has identified the following revenue adjustments it proposes to submit as part of its annual revenue requirement:

- under/over recoveries from prior period revenues;
- electrical safety inspection service levy;
- national energy market levy;
- trunk mobile radio;
- excess GSL costs; and
- NEM and retail contestability related costs.

Each of the above revenue adjustments is discussed fully in chapter 32 of this *Regulatory Proposal.*

24. Efficiency Benefit Sharing Scheme

24. Efficiency Benefit Sharing Scheme

24. Efficiency Benefit Sharing Scheme

24.1. Background

Clause 6.5.8 of the *Rules* provides that the AER must develop an efficiency benefit sharing scheme.

Clause 2.3.2 of the AER's Efficiency Benefit Sharing Scheme (EBSS) sets out that:

- The AER will permit Aurora to propose a range of additional cost categories for exclusion from the operation of the EBSS. These categories must be specific to Aurora, and Aurora must provide an identifiable reason for exclusion, and should not involve an ongoing business activity. Aurora must propose cost categories for exclusion from the EBSS in its *Regulatory Proposal* prior to the commencement of the *Regulatory Control Period* during which the EBSS will be applied.
- Aurora must justify a proposal to exclude cost categories to the AER. Aurora must also not seek to exclude categories of costs that could otherwise be regarded as controllable costs, for example, labour and materials costs and service provider costs.

The EBSS also states that proposed adjustments to the forecast opex will only be accepted by the AER if they are for changes in costs the AER considers are uncontrollable and will not adversely impact the operation of the EBSS.

24.2. Proposed cost exclusions

The EBSS specifically excludes from the operation of the EBSS the cost of recognised pass through events as well as operating costs on non-network alternatives.

Consistent with the AER's recent decision on the Victorian distribution businesses, Aurora proposes the following cost categories also be excluded for the purposes of calculating the EBSS, being:

- superannuation costs relating to defined benefit and retirement schemes;
- demand management incentive scheme amounts (DMIA);
- debt raising costs;
- self insurance costs; and
- GSL payments.

There are also a number of cost categories that Aurora considers are uncontrollable costs and Aurora proposes should also be excluded for the purposes of calculating the EBSS, being:

- electrical safety inspection levy;
- national energy market levy;
- trunk mobile radio charges; and
- NEM and retail contestability costs.

24.3. Pass through events

In addition to the pass through events provided by Chapter 10 of the *Rules*, Aurora has proposed that the following events are treated as pass through events as part of the AER's final Determination:

- natural disaster event;
- bushfires event;
- storms event;
- industry restructure event;
- retailer of last resort event;
- carbon tax event;
- insurer credit risk event;
- liability above insurance cap event; and
- feed in tariff event.

These events are discussed in detail in chapter 27 of the *Regulatory Proposal*.

Consistent with the provisions of clause 2.3.2 of the AER's EBSS, Aurora proposes that its nominated additional pass through events are also excluded for the purposes of calculating the EBSS.

24.4. Non-network alternatives

Aurora is proposing to undertake a number of non-network alternatives during the forthcoming *Regulatory Control Period* and has included these proposals as demand management forecasts within its operating expenditure forecasts. These operating expenditure forecasts are specifically targeted at alternative expenditure to capital investment in Aurora's distribution network and are discussed in detail in section 12.4.6 of this *Regulatory Proposal*.

Consistent with the provisions of clause 2.3.2 of the AER's EBSS, Aurora proposes that this demand management operating expenditure is also excluded for the purposes of calculating the EBSS.

24.5. Victorian distribution business' final decision

In the AER's recent decision on the Victorian distribution business, the AER concluded that a number of additional events would be excluded for the purposes of calculating the EBSS. The AER found:[1]

> *In accordance with section 2.3.2 of the EBSS and this final decision, the AER concludes that the following will be excluded from calculation of EBSS carryover amount for the forthcoming regulatory period:*
>
> - *superannuation costs for defined benefits schemes;*
> - *DMIA expenditure;*
> - *expenditure on non-network alternatives; and*
> - *recognised pass through events and recognised regulatory change events or service standard events. However the AER clarifies that regulatory change events or service standard events which are rejected by the AER as pass through events will be included as opex when calculating EBSS carryover amounts. Events which qualify as pass through events but do not satisfy the materiality threshold will be included as opex when calculating EBSS carryover amounts.*
>
> *In addition, in order to meet the requirements set out in clause 6.5.8(c)(2) of the NER in implementing the EBSS, the AER will exclude the following cost categories from the operation of the EBSS in the forthcoming regulatory control period. Specifically, the exclusion of these cost categories will provide the Victorian DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure:*
>
> - *debt raising costs;*
> - *self insurance costs; and*
> - *GSL payments.*

Consistent with the AER's recent decision, Aurora proposes that these cost categories also be excluded for the purposes of calculating the EBSS.

1 Final decision, Victorian electricity distribution network service providers, Distribution determination 2011-2015, October 2010, page 655.

24.6. Additional exclusions

There are a number of cost categories that Aurora considers, by their nature, are beyond the control of Aurora and should be excluded for the purposes of calculating the EBSS, being:

- electrical safety inspection levy;
- national energy market levy;
- trunk mobile radio charges; and
- NEM and retail contestability costs.

These costs are discussed in more detail in chapter 23 of this *Regulatory Proposal.*

24.6.1. Electrical safety inspection levy

The electrical safety inspection service levy, as defined in the ESIA Act, is[2]:

> *"..an annual charge, payable to the Crown by an electricity entity for the operation and administration of the electrical safety inspection service administered by the responsible Department.."*

The amount of the levy is determined by WST and is beyond the control of Aurora.

Aurora proposes that this cost category be excluded for the purposes of calculating the EBSS.

24.6.2. National energy market levy

The ESI Act provides for the Crown to recover from an electricity entity, in each financial year[3] :

> *".. a charge representing part or all of the cost of the State's funding commitments in respect of the AEMC."*

The Minister for Energy notifies Aurora of the amount of the charge each financial year and it is beyond the control of Aurora.

Aurora proposes that this cost category be excluded for the purposes of calculating the EBSS.

24.6.3. Trunk mobile radio

Aurora contributes to a joint government department cost of running the trunk mobile radio (TMR) network within Tasmania for emergency services. Arrangements surrounding the provision of this service to all Tasmanian Government agencies have yet to be finalised and costs for the provision of this service still remain uncertain.

This charge is calculated by the Police and Emergency Management Department each financial year and is beyond the control of Aurora.

Aurora proposes that this cost category be excluded for the purposes of calculating the EBSS.

2 Clause 121B(1).
3 Clause 121(1).

24.6.4. NEM and retail contestability related costs

Tasmania's entry to the NEM has been progressively introduced since May 2005. A final decision on FRC is still with the Government, with no indication of likely commencement or timing. Given the uncertainty surrounding a Government decision on this matter and that the costs associated with any decision are beyond the control of Aurora, Aurora proposes that this cost category be excluded for the purposes of calculating the EBSS.

24.7. Forecast operating expenditure for EBSS purposes

Table 103 below outlines Aurora's operating expenditure forecasts for the purposes of calculating the EBSS for the forthcoming *Regulatory Control Period*.

Table 103

Operating expenditure for EBSS purposes

Aurora's EBSS operating expenditure					
$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Total *Standard Control Services* operating expenditure	70.638	68.644	68.100	67.299	65.449
EBSS exclusion adjustments	10.507	10.745	10.619	10.513	10.427
Total operating expenditure for EBSS purposes	**60.131**	**57.899**	**57.481**	**56.786**	**55.022**

25. Service Target Performance Incentive Scheme (STPIS)

25. Service Target Performance Incentive Scheme (STPIS)

25. Service Target Performance Incentive Scheme

25.1. Service Target Performance Incentive Scheme objectives

The role of the AER Service Target Performance Incentive Scheme (STPIS) is to provide incentives for Aurora to maintain and improve service performance as set out in the *Rules*.

To that end, the AER STPIS:

(1) defines the performance incentive parameters that measure Aurora's service performance;

(2) sets out the requirements with which the values to be attributed to the parameters must comply;

(3) will be used to decide the service standards financial reward or penalty component of Aurora's Determination; and

(4) provides guidance about the approach the AER will take in reviewing Aurora's service performance.

The AER objectives are that the STPIS:

(a) is consistent with the national electricity objective in the NEL;

(b) is consistent with the *Rules* which requires that the AER must take into account:

- (i) the need to ensure that benefits to consumers likely to result from the STPIS are sufficient to warrant any reward or penalty for Aurora;
- (ii) any regulatory obligation or requirement to which Aurora is subject;
- (iii) the past performance of Aurora's network;
- (iv) any other incentives available to Aurora under the *Rules* or a relevant Distribution Determination;
- (v) the need to ensure that the incentives are sufficient to offset any financial incentives Aurora may have to reduce costs at the expense of service levels;
- (vi) the willingness of the customer or end user to pay for improved performance in the delivery of services; and
- (vii) the possible effects of the STPIS on incentives for the implementation of non-network alternatives;

(c) promotes transparency in:

- (i) the information provided by Aurora to the AER; and
- (ii) the decisions made by the AER.

The AER is required by the *Rules* to include a STPIS as component of a Building Block Determination for the provision of *Standard Control Services*[1] *by distributors. To this end, the AER published a Guideline "Electricity distribution network service providers service target performance incentive scheme"* (the STPIS Guideline), most recently amended in November 2009, describing the formation and application of the STPIS.

In its application of a STPIS, the AER is obliged to consider jurisdictional GSL Schemes and performance targets[2]. The Tasmanian performance standards are contained within the *TEC*[3] and OTTER has noted that the performance standards will not be revised, but that the boundaries of the communities may be reviewed to account for community growth. The jurisdictional GSL Scheme is provided in the GSL Guideline.

25.2. AER proposed scheme

25.2.1. Introduction

The AER described its proposal for the application of the STPIS to Aurora in the final *Framework and Approach*. The STPIS has, potentially, four components: Reliability of Supply; Quality of Supply; Customer Service; and a GSL Scheme, with the first three components contributing to the S-factor that is used to adjust

1 *Rules*, Chapter 6, Part C.
2 *Rules*, clause 6.6.2.
3 *TEC*, clause 8.6.11.

allowable revenues. The STPIS may place a maximum five percent of revenue at risk per annum under an S-factor scheme[4]; the AER has proposed that five percent of Aurora's revenue be at risk.

The AER has chosen not to include a Quality of Supply component. The AER's proposed application of the remaining components is discussed below.

25.2.2. Reliability of supply component

There are three parameters available to the AER in the Reliability of Supply Component of the STPIS (SAIDI, SAIFI, and MAIFI), with targets for these parameters based on the distributor's historical performance and rates based on the value of customer reliability (VCR) as determined by the AER.

The AER has proposed that:

- SAIDI and SAIFI targets be applied to existing categories given in the jurisdictional performance standards with the targets set using historical data consistent with the STPIS guideline;
- the VCR should be $95,700 per MWh for the:
  - Critical Infrastructure; and
  - High Density Commercial categories; and
- $47,850 per MWh for the:
  - Urban and Regional Centres;
  - High Density Rural; and
  - Lower Density Rural categories,

with the values given in September 2008 dollars;

- outages due to load shedding for certain reasons, outages due to failure of the shared transmission network or transmission connection assets (with a caveat), outages due to the exercise of a power under national or local electricity legislation, or outages on Major Event Days be excluded from consideration; and
- Major Event Days be determined using the 2.5β methodology.

25.2.3. Guaranteed service level scheme

The AER notes that it will apply the standard GSL Scheme given in the STPIS Guideline only if there is no relevant jurisdictional GSL Scheme. There is an existing jurisdictional GSL Scheme provided in the GSL Guideline, compliance with which is a licence obligation upon Aurora. OTTER has indicated to the AER that it does not intend to repeal the Guideline, although it has also indicated to Aurora that it does not intend to codify in the GSL Guideline or the *TEC* either the single event safety net or the risk sharing mechanism that currently applies. Accordingly, the AER proposes to adopt the GSL Scheme given in the GSL Guideline.

4 STPIS Guideline, section 2.5(a).

25.2.4. Customer service component

There are four parameters available to the AER in the Customer Service Component of the STPIS (telephone answering, streetlight repair, new connections and response to written enquiries) of which only telephone answering is mandatory. The maximum revenue at risk must be ± 1 percent of DNSP revenue for each year of the *Regulatory Control Period*, with no more than ±0.5 percent at risk for any given component.[5]

The AER has proposed that only the mandatory telephone answering parameter be included and operated as per the SPTIS Guideline, and that the revenue at risk be set at 0.5 percent.

25.3. Aurora proposed scheme

25.3.1. Introduction

The principles of the STPIS proposed by Aurora are discussed below.

25.3.2. Reliability of supply component – network segmentation

Aurora understands the AER's approach to network segmentation to mean that each of the five categories listed in Table 3 of Chapter 8 of the *TEC* (Critical Infrastructure, High Density Commercial, Urban and Regional Centres, High Density Rural, and Lower Density Rural) is considered to be a distinct segment. In consequence, each category will have its own series of SAIDI and SAIFI targets based upon appropriate historical reliability data. Aurora supports the AER's proposed approach to network segmentation.

25.3.3. Reliability of supply component – calculation methodology

The reliability of supply component of the STPIS proposed by the AER is intended to use unplanned SAIDI and SAIFI as the parameters. Further, Appendix A of the STPIS Guideline requires that SAIDI and SAIFI be calculated using customer numbers. Aurora is unable to adequately meet this requirement.

Aurora notes that the reliability of supply data used to calculate GSL payments is inadequate to set SAIDI and SAIFI targets. The GSL system uses the Aurora "customer to asset link", whereby installations are "linked" to transformers. The customer to asset link is currently between 90 percent and 95 percent complete. At the beginning of the five year period required to set performance standards, the customer to asset link project had only just commenced and was estimated to be 80 percent complete. Consequently, any targets set using this data will be wrong to a greater or lesser extent. Aurora considers that it is inappropriate to place any of its annual revenue at risk in a scheme that has poorly set targets.

Aurora's current reliability reporting system monitors outages down to transformer level; that is, the system can identify whether a transformer has experienced an outage and the duration of that

5 STPIS Guideline, section 5.2.

outage. The capacity of the transformer (in kVA) is then used in the reliability calculations in conjunction with the outage data. Additionally, the number of customers affected by a transformer outage is generally estimated from the capacity of the transformer assuming that a customer has certain, standard demand. Using this kVA approach, Aurora can confidently provide an outage history back to 2004. On this basis, Aurora proposes that the kVA approach to calculating the SAIDI and SAIFI analogues be continued.

25.3.4. Incentive rates

Clause 3.2.2 of the STPIS Guidelines sets out a methodology for developing incentive rates. Aurora accepts this methodology as outlined below.

Reliability of supply component – value of customer reliability

The AER has proposed that the VCR should be $95,700 ($ September 2008) per MWh for the Critical Infrastructure and High Density Commercial categories and $47,850 ($ September 2008) per MWh for the Urban and Regional Centres, High Density Rural and Lower Density Rural categories. Independent evaluation of the methodology used to ascertain the VCR values indicates that the incremental differences between the AER's proposed VCRs and the appropriate values of VCRs for Tasmania, given the differences in industry sector mixes, are minimal. Aurora therefore supports the use of the AER's proposed values for VCR.

SAIDI and SAIFI weighting

As Aurora proposes a network segmentation other than the network type applied by clause 3.2.2(g) of the STPIS Guideline, Aurora proposes SAIDI and SAIFI weightings as outlined in Table 104.

Aurora has used the weightings provided in Table 1 of the STPIS Guideline and the direction provided by the AER in regard to the application of VCR as the basis for its proposed weightings. Aurora considers that the:

- Critical Infrastructure and High Density Commercial categories are comparable to the CBD feeder classification;
- Urban and Regional Centres category is comparable to the Urban feeder classification; and
- High Density Rural and Lower Density Rural categories are comparable to the Rural (short and long) feeder classification.

Aurora proposes that the AER's CBD, Urban and Rural (short and long) weightings are applied to the Aurora network segmentations.

Table 104

Weightings for SAIDI and SAIFI

Parameter segment	Ratio of unplanned SAIDI to unplanned SAIFI
Critical Infrastructure	1.13
High Density Commercial	1.13
Urban and Regional Centres	0.97
High Density Rural	0.92
Lower Density Rural	0.92

Incentive rate calculation

The calculation for unplanned SAIDI within the STPIS Guideline at clause 3.2.2(h) requires that the incentive rate is calculated by:

(1) multiplying the portion of VCR assigned to the unplanned SAIDI (in $/MWh) by the average annual energy consumption by network type (in MWh) expected for the *Regulatory Control Period*;

(2) dividing by the average of the smoothed Annual Revenue Requirement for the *Regulatory Control Period* (in $, real referenced to the first *Regulatory Year* of the *Regulatory Control Period*) as determined by the AER in the relevant Distribution Determination; and

(3) dividing by the average number of minutes in a Regulatory Year.

The calculation for unplanned SAIFI within the STPIS Guideline at clause 3.2.2(i) requires that the incentive rate is calculated by:

(1) multiplying the portion of VCR assigned to the unplanned SAIFI (in $/MWh) by the average annual energy consumption by network type (in MWh) expected for the *Regulatory Control Period*;

(2) dividing by the average of the smoothed Annual Revenue Requirement for the *Regulatory Control Period* (in $, real referenced to the first Regulatory Year of the *Regulatory Control Period*) as determined by the AER in the relevant Distribution Determination;

(3) dividing by the average number of minutes in the relevant *Regulatory Year;* and

(4) multiplying by the average of the annual performance targets for unplanned SAIDI in the *Regulatory Control Period* and dividing by the average of the annual performance targets for unplanned SAIFI in the *Regulatory Control Period*.

Average annual energy consumption

Aurora has determined the annual energy consumption for the *Regulatory Control Period* by examining the measured annual energy in the 2009-10 financial year and applying the proportion of consumption for each network type to the forecast annual energy consumption for the forthcoming *Regulatory Control Period*, as shown in Table 105.

Table 105

Average annual energy consumption

Parameter segment	Average annual energy consumption (MWh)
Critical Infrastructure	158,615
High Density Commercial	225,470
Urban and Regional Centres	2,975,455
High Density Rural	767,450
Lower Density Rural	558,129

Average smoothed annual revenue requirement

The STPIS Guideline requires that the average of the smoothed Annual Revenue Requirement for the *Regulatory Control Period* (in $ real, referenced to the first Regulatory Year of the *Regulatory Control Period*) is utilised in calculating the incentive rate.

Aurora's calculation of its annual revenue requirement is detailed in chapter 30 of this *Regulatory Proposal*. Aurora proposes an average smoothed Annual Revenue Requirement for the *Regulatory Control Period* of $291.83 million as shown in Table 106.

Table 106

Annual revenue requirement

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2016-16 ($m)	2016-17 ($m)
Notional building block smoothed revenue	292.53	292.18	291.83	291.48	291.13
Average smoothed revenue	291.83				

Incentive rates

Utilising the formulas prescribed within the STPIS Guideline Aurora has calculated the incentive rates to apply in the forthcoming *Regulatory Control Period* as shown in Table 107.

Table 107

Incentive rates

	Parameter Segment	Incentive Rate
SAIDI	Critical Infrastructure	0.00594
	High Density Commercial	0.00845
	Urban and Regional Centres	0.05175
	High Density Rural	0.01299
	Lower Density Rural	0.00945
SAIFI	Critical Infrastructure	0.933
	High Density Commercial	0.597
	Urban and Regional Centres	4.678
	High Density Rural	1.452
	Lower Density Rural	1.275

25.3.5. Exclusions

Reliability of supply component – major event day calculation

The AER proposes that Major Event Days be excluded from STPIS calculations and proposes that Major Event Days be identified using the "2.5β" methodology. Aurora supports this approach, although notes that the calculation of SAIDI will be based upon kVA rather than actual customer numbers.

Reliability of supply component – exempt outages

The AER proposes that the following may be excluded from consideration under the STPIS standard exclusions:

(1) load shedding due to a generation shortfall;

(2) automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition;

(3) load shedding at the direction of AEMO or a system operator;

(4) load interruptions caused by a failure of the shared transmission network;

(5) load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and Aurora is responsible for transmission connection planning;

(6) load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to Aurora; and

(7) all events that occur on a MED where daily unplanned SAIDI for the DNSP's distribution network exceeds the major event day boundary, as set out in appendix D of the STPIS Guideline.

Aurora notes that Section 14(2) of the ESI Act provides that:

An electricity entity is not obliged to supply electricity to a customer if–

(a) the supply would overload the power system or prejudice in some other way the supply of electricity to other customers; or

(b) the supply would result in contravention of the conditions of the electricity entity's licence; or

(c) the supply would result in risk of fire or some other risk to life or property; or

(d) the supply is or needs to be interrupted:

    (i) in an emergency; or

    (ii) in circumstances beyond the electricity entity's control; or

    (iii) for carrying out work on electricity infrastructure; or

    (iv) to comply with a direction to the electricity entity under this Act; or

(e) the electricity entity is exempted from the obligation by regulation.

Aurora considers that the application of these two sets of conditions provides a series of outages that can be considered to be outside of the consideration of the STPIS. Aurora proposes that the following outages should also be exempted:

- high fire danger days, when Aurora's auto-reclosers are set to lock-out immediately rather than the standard "trip three times then lock-out"; and
- outages at the direction of emergency personnel.

High fire danger days

In its final Framework and Approach for Aurora the AER noted, in relation to high fire danger days[6]:

> *".. On such days Aurora has the option, when a momentary outage occurs, to set auto-reclosers to trip and return electricity supply. Aurora may choose not to exercise this option as the supply would result in risk of fire or some other risk to life or property. The exercise of Aurora's right or discretion would be in accordance with s 26(2)(c) of the ESI Act. The interruption to supply would be caused by the exercise of the right or discretion to interrupt the supply of electricity and would fall within clause 3.3(a)(7) of the STPIS.*
>
> *The AER notes that Aurora has not specified when it considers that a day would be of 'high fire risk'. The AER will consider the appropriate definition of 'high fire risk days' as part of its final determination for Aurora."*

Aurora provides the following definition for high fire danger days to assist to AER in its considerations.

> *A high fire danger day means: a day of total fire ban as advised by the Tasmania Fire Service in accordance with section 70 of the Fire Service Act 1979.*

Aurora proposes that outages arising from high fire danger days should be excluded from consideration under the STPIS.

Emergency personnel direction

In its final Framework and Approach for Aurora the AER noted, in relation to outages at the direction of emergency personnel[7]:

> *"..Aurora would be acting in accordance with section 26(2)(d)(i) of the ESI Act and the exercise of its right or discretion would fall within clause 3.3(a)(7) of the STPIS. As such, the AER considers that these interruptions may be excluded from the financial effects of the scheme."*

Aurora proposes that outages at the direction of emergency personnel should be excluded from consideration under the STPIS.

6 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 101.

7 Ibid. page 101.

25.3.6. Customer service component

Aurora generally supports the AER's proposed approach to the application of the Customer Service component of the S-factor scheme.

Aurora proposes that for the first three years of the forthcoming *Regulatory Control Period,* the STIPS should exclude the telephone answering parameter within the customer service component.

Aurora's PABX has previously not retained the detailed information required for STPIS targets for more than 42 days before the system automatically purges the last record in order to record a new record. Aurora commenced capturing this information in March 2011 and as such has the required information from 26 January 2011.

Aurora proposes that further performance data should be collected for the first three years of the forthcoming *Regulatory Control Period* to allow a robust performance target to be set for the final two years of the *Regulatory Control Period.*

25.3.7. Guaranteed service level scheme

The AER proposes to implement the GSL Scheme provided in the OTTER GSL Guideline. Aurora notes that only part of the scheme is articulated in the GSL Guideline; the remainder, being the single event safety net and the risk sharing mechanism are provided in the OTTER 2007 Determination. While the OTTER GSL Guideline has no expiry date, and OTTER is not intending to repeal the GSL Guideline, the 2007 Determination terminates on 30 June 2012. This termination leaves Aurora with a potentially uncapped GSL liability, which was not the original intention of OTTER when the scheme was introduced.

Nonetheless, Aurora supports the AER's proposal to implement the GSL Scheme as articulated in the GSL Guideline so long as the GSL scheme implemented by the AER includes the OTTER mechanisms included within the 2007 Determination.

25.3.8. Revenue at risk

The AER has proposed that the maximum revenue at risk be applied to Aurora in the STPIS, with 0.5 percent of annual revenue attached to the Customer Service Component and 4.5 percent of annual revenue attached to the S-factor.

Aurora has concerns at the quantum of the revenue at risk and discusses these concerns in the following section.

Aurora notes that this proportion of annual revenue at risk is significantly larger than previously applied in respect of the Service Incentive Scheme applied by OTTER. OTTER placed 1.25 percent of Aurora's revenue at risk in the previous *Regulatory Control Period*, with a similar amount of total revenue being placed at risk over the current *Regulatory Control Period.* Aurora considers that an increase of such magnitude does not adequately consider OTTER's considerations of the appropriate revenue at risk when making the 2007 Determination and OTTER's observation that reporting of category and community performance was sufficient to ensure no loss of reliability.

Aurora notes that the current GSL scheme that the AER proposes to partially implement was designed as a stand-alone Service Incentive Scheme, with an appropriate revenue at risk component.

OTTER noted in its final decision that[8]:

> *"..two mechanisms are thus designed to deal with different risks, the first being the risk of a series of events over the period that may result in Aurora paying to customers an amount materially higher than expected, the second being the risk of a single large event. However, the Regulator recognises that there is a degree of interaction between the two mechanisms. Thus, as Aurora will be able to recover half of the additional payments above the revised duration threshold from customers in the following year, only the remainder will be able to be taken into account in calculating whether Aurora has reached the cap for payments over the period.*
>
> *In the light of this, the Regulator has also considered whether the exemption for widespread interruptions due to 'rare' events should remain. Whilst it is anticipated the risk sharing provision provided through an adjustment to the threshold should manage most single large events, the Regulator recognises that there could be other rare events where the financial risk may be very significant. In these instances it may be to customers, as well as Aurora's, benefit to manage these through an exemption rather than a risk sharing mechanism."*

The potential removal of the single outage safety net and the risk sharing mechanism for the forthcoming Distribution Determination renders the revenue at risk associated with the GSL Scheme much greater than intended by OTTER. Aurora proposes, therefore, that to recognise this additional revenue risk to Aurora that the revenue at risk associated with the GSL scheme should also be considered when setting the maximum revenue at risk for the S-factor components of the STPIS.

In particular, Aurora proposes that the revenue at risk attached to the S-factor be adjusted downwards to account for the historical impact of GSL payments under the scheme that was designed as a stand-alone Service Incentive Scheme and set at a value of a maximum of 2.5 percent of annual revenue.

Aurora has previously made mention of this additional risk and the AER noted in the final Framework and Approach for Aurora that:[9]

> *".. The revenue at risk mitigates the risk to customers and Aurora of significant fluctuations in prices over the course of a Regulatory Control Period. A lower level of revenue at risk reduces the size of the incentive on Aurora to improve reliability. The AER considers that the size of the incentive and the volatility of the scheme are appropriately balanced with a 5 percent cap on revenue at risk. The AER considers that in this instance, a 2.5 percent cap is not appropriate as it results in a reduction to the size of the incentive that the scheme provides Aurora to maintain and improve network reliability. The AER is satisfied that a 5 per cent cap on revenue at risk represents an appropriate balance between providing incentives for reliability improvements and the risks on DNSPs and customers.*
>
> *Further, unlike the STPIS, the TEC GSL scheme does not influence the tariffs that Aurora's customers are charged for electricity. The GSL scheme only presents a financial risk to Aurora. This risk is mitigated by the component of the revenue allowance Aurora is provided to cover the expected cost of the scheme."*

Aurora considers that it has sufficient incentive to achieve an expected level of reliability for customers by means of the minimum reliability requirements outlined in the *TEC* and the jurisdictional GSL Scheme. Indeed, Aurora has forecast that it will not be investing in capital programs designed to improve the level of reliability for customers on the understanding that its current and future programs are designed to meet the regulatory requirements of the *TEC* standards.

To provide further larger incentives to Aurora would infer that Aurora should invest more heavily in its distribution network ("gold-plate") on the understanding that derived improvements in reliability above those required by the *TEC* would also produce additional revenues. This appears to be a perverse outcome for customers, in that Aurora would spend more than reasonably required to achieve the regulatory imposed levels of reliability and also be rewarded for this inefficient investment. The net result of this outcome would be that customers would pay more through their tariffs than otherwise expected if such an incentive did not exist.

Aurora understands that the *Rules* require the *AER* to implement a STPIS as part of its Distribution Determination; however the AER does have discretion in the level of the incentives it provides under the STPIS. Aurora therefore proposes that the AER set the revenue at risk for Aurora at a level of 2.5 percent of revenue to remove this perverse incentive to seek excess monopoly rents from its customers.

8 Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Final Report and Proposed Maximum Prices, September 2007, page 233.

9 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 110.

25.3.9. Setting the targets

Aurora is not proposing any specific capital investment aimed at substantive improvements in reliability in the forthcoming *Regulatory Control Period*. Aurora therefore proposes targets based on the average performance over the past five *Regulatory Years*, modified by the remaining reliability improvement program (2010-11 and 2011-12) within the current *Regulatory Control Period* as per the methodology proposed in clause 3.2.1(a) of the STPIS Guideline.

Aurora's SAIDI STPIS targets for the 2012-17 *Regulatory Control Period* are shown in Table 108.

Table 108

SAIDI STPIS targets

SAIDI	Forecast target				
Parameter segment	2012-13 (mins)	2013-14 (mins)	2014-15 (mins)	2015-16 (mins)	2016-17 (mins)
Critical Infrastructure	50	50	50	50	50
High Density Commercial	42	42	42	42	42
Urban and Regional Centres	93	93	93	93	93
High Density Rural	297	297	297	297	297
Lower Density Rural	399	399	399	399	399

Aurora's SAIFI STPIS targets for the 2012-17 *Regulatory Control Period* are shown in Table 109.

Table 109

SAIFI STPIS targets

SAIFI	Forecast target				
Parameter segment	2012-13 (int)	2013-14 (int)	2014-15 (int)	2015-16 (int)	2016-17 (int)
Critical Infrastructure	0.28	0.28	0.28	0.28	0.28
High Density Commercial	0.53	0.53	0.53	0.53	0.53
Urban and Regional Centres	1.06	1.06	1.06	1.06	1.06
High Density Rural	2.88	2.88	2.88	2.88	2.88
Lower Density Rural	3.21	3.21	3.21	3.21	3.21

26. Demand Management Incentive Scheme

26. Demand Management Incentive Scheme

26. Demand Management Incentive Scheme

26.1. Overview

The Aurora Demand Management Incentive Scheme (DMIS), issued by the AER in October 2010, is defined by the establishment of a Demand Management Incentive Allowance (DMIA) of $2 million to Aurora over the forthcoming *Regulatory Control Period*. In its *Framework and Approach* paper the AER confirmed that it would be likely to apply its final DMIS to Aurora in the forthcoming *Regulatory Control Period*[1].

This chapter sets out the Rules requirements relevant to the DMIS and the application of the DMIS (and therefore the DMIA) to Aurora. It also provides a summary of the non-network alternative initiatives proposed for the forthcoming *Regulatory Control Period*.

26.2. Rules requirements

The *Rules* provide for the following in relation to the DMIS:

- clauses 6.3.2(a)(3) and S6.1.3 require Aurora to specify in its building block proposal how the DMIS is to apply to it during the 2012-17 *Regulatory Control Period*;
- clause 6.4.3(5) requires Aurora to determine its annual revenue requirement for each *Regulatory Year* of the 2012-17 *Regulatory Control Period* using a building block approach, under which one of the building blocks is the revenue increments or decrements arising from the application of the DMIS (and other schemes) for each year;
- clause 6.6.3 allows the AER, in accordance with the distribution consultation procedures, to develop and publish a DMIS to provide incentives for the DNSPs to implement efficient non-network alternatives or to manage the anticipated demand for *Standard Control Services* in some other way;
- clause 6.8.1(b)(4) requires the AER to set out in its *Framework and Approach* paper the AER's likely approach to the application of the DMIS to Aurora; and
- clause 6.12.1 requires a Distribution Determination to be predicated on a decision on how any applicable scheme, including the DMIS, is to apply to Aurora;

In relation to clauses 6.6.3 and 6.8.1(b)(4), the AER released its decision regarding its DMIS for Aurora in October 2010. The Final *Framework and Approach Paper* issued in November 2010 states the AER's intention to apply Aurora's DMIS in the 2012-17 *Regulatory Control Period*[2].

In relation to clauses 6.3.2(a)(3) and S6.1.3, Aurora describes below how it will apply its DMIA over the forthcoming *Regulatory Control Period*, and describes the initiatives that it proposes to fund under the allowance.

26.3. Application of DMIS to Aurora

Aurora's DMIS is applied in the form of a DMIA which allows the recovery of $400,000 (in nominal terms) for each *Regulatory Year* of the forthcoming *Regulatory Control Period*. This equates to a $2 million allowance in total across the entire *Regulatory Control Period*. There is no foregone revenue component to the DMIS as Aurora is subject to a revenue cap form of control for *Standard Control Services*.

In accordance with clause 6.4.3(a)(5) of the *Rules*, Aurora has included a revenue increment of $400,000 for the DMIS, on an ex-ante basis, in its calculation of the annual revenue requirement for each *Regulatory Year* of the forthcoming *Regulatory Control Period* in the Post Tax Revenue Model (PTRM). Aurora based this forecast on the assumption that it will spend this allowance, in its entirety, on demand management projects.

1 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 136.

2 AER, Demand Management Incentive Scheme Aurora Energy, Regulatory Control period commencing 1 July 2012, October 2010, page 1.

Although these amounts are allocated annually through Aurora's building block mechanism Aurora notes that it will expend funding on demand management projects as required throughout the forthcoming *Regulatory Control Period*. This is in accordance with Aurora's DMIS.

Aurora notes its obligations to fulfil its reporting requirements in regard to its expenditure under the DMIA. A total of $40,000 has been allocated so that Aurora may fulfil its reporting obligations in accordance with the *Rules* and its DMIS requirements.

26.4. Demand management strategy

Aurora notes the AER's intention that an assessment of the scheme's operation in the forthcoming *Regulatory Control Period* will inform the application of demand management incentive schemes to Aurora in subsequent *Regulatory Control Periods*[3]. *Consequently Aurora is driven to achieve favourable outcomes for projects undertaken in the forthcoming Regulatory Control Period*, which will form the foundation for future work in the non-network alternatives sphere.

In the forthcoming *Regulatory Control Period* Aurora's overarching demand management strategy will focus on obtaining an insight into non-network opportunities; and developing the practical experience required to progress such initiatives. Aurora will build its capacity and experience through the implementation of a suite of research and development initiatives and pilot projects.

3 AER, Demand Management Incentive Scheme Aurora Energy Regulatory control period commencing 1 July 2012, October 2010, page 10.

These projects are consistent with the AER's intended design of the DMIS to allow "expenditure on activities to facilitate the investigation and pursuit of efficient, broad-based or innovative demand management projects and programs"[4]. Also in keeping with the objectives of the AER, Aurora considers that its proposed projects have the potential to lead to the implementation of efficient non-network solutions within and beyond 2017.

26.5. DMIA expenditure

In recognition of the benefits of pursuing non-network solutions to meet user demand Aurora engaged expert consultants Futura Consulting to review the adequacy of existing incentives and schemes and develop future options. On the basis of analysis undertaken by Futura Consulting, Aurora has developed a suite of projects to be progressed under the DMIA.

The total value of the programs equates to the DMIA of $2 million allowed by the AER in its DMIS for Aurora. Aurora anticipates that this will comprise only operating expenditure, with the appropriate load control architecture; residential and small business water heater; and power factor correction potential studies being externally resourced. Table 110 sets out the proposed expenditure to be sourced from the DMIA for each *Regulatory Year* of the *Regulatory Control Period*.

4 AER, Final Decision, Demand Management Incentive Scheme Aurora Energy Regulatory control period commencing 1 July 2012, October 2010, page 9.

Table 110

Proposed projects under the DMIA

Nominal dollars	2012-13 $'000	2013-14 $'000	2014-15 $'000	2015-16 $'000	2016-17 $'000	TOTAL $'000
Load control architecture		250				**250**
Residential and small business water heater	250					**250**
Power factor correction potential				100	50	**150**
Energy storage	100	100	100			**300**
Institutional partnership	50	50	50	50	50	**250**
LED streetlight	40	40	40	40	40	**200**
Other programs			200	200	160	**560**
DMIA reporting		10	10	10	10	**40**
Total	**400**	**500**	**400**	**400**	**300**	**2,000**

The DMIS is provided as a mechanism to encourage the consideration by Aurora of "more innovative, perhaps untested, non-network alternatives, which may not be approved under the capital and operating expenditure assessment clauses in the *Rules*"[5]. With regard to this objective, and on the basis of analysis undertaken by Futura Consulting, Aurora proposes to progress the following demand management projects under the DMIA.

26.5.1. Load control architecture

This trial will investigate the costs, benefits and functionality in relation to the most appropriate load control architecture and technology for residential and small business customers. This is important work because uncontrolled space heating and water heating load associated with these customers is a key driver of Aurora's capital expenditure and are estimated to account for almost 30 percent or some 300MVA of Aurora's system peak.

26.5.2. Residential and small business water heaters

This study would provide Aurora with an understanding of the installed stock of electric water heaters connected to its network support. This would support the development of an electric hot water strategy by collating quantitative data about the volume, type and usage profile of systems, both existing and forecast in future years.

26.5.3. Power factor correction potential

This study would identify customers with poor power factor and offer technical expertise and resources, business case information and potentially financing solutions to assist with the installation of power factor correction equipment. This program would allow Aurora to quantify the potential benefits and costs of power factor correction on an ongoing basis. Aurora intends to implement power factor correction initiatives at a relatively low-cost by leveraging partnerships with equipment suppliers.

26.5.4. Energy storage

This trial aims to test the ability of a range of distributed generation and energy storage solutions to provide network support functions. Trials will focus on exploring the potential of energy storage and embedded generation. This trial is important because energy storage can be used as a tool to balance supply and demand and provides a good opportunity to integrate large amounts of renewable energy.

26.5.5. Institutional partnership

This trial aims to create an energy partnership with a local council to generate peak demand reductions, and energy savings, through municipal retrofits, and community outreach. It would develop community specific educational and marketing materials, and outreach programs, to enhance participation in measures including load control of water heating, renewable energy technologies, and energy efficiency programs.

26.5.6. LED streetlights

This research and development program would involve the trial of light-emitting diode (LED) streetlighting. The objective of this project is to assist Aurora to identify the most cost-effective applications of LED streetlighting and provide data to develop a business case for potential wider-scale implementation in conjunction with local councils. This work is important because streetlighting is estimated to account for up to one percent of the evening peak and technology such as LEDs, offer the potential for significant energy and peak demand savings of up to 50 percent of the existing energy and peak demand of luminaires in current use.

26.5.7. Other programs

A $560,000 portion of the DMIA allowance is unallocated to specific projects thus far, and has been included in the work program to implement programs later in the *Regulatory Control Period*. The key reason for this is that a load control architecture study will influence the composition and need for additional programs. This residual allowance can therefore be used to pursue emergent opportunities as they arise.

26.5.8. DMIA reporting requirements

Aurora is required to provide information to the AER so that it may assess expenditure incurred under the DMIA. As set out above in Table 110 Aurora proposes expenditure of $40,000 across the *Regulatory Control Period* to cover annual reporting against the criteria established in the scheme as part of the AER's regulatory information order. As expenditure on demand management activities is either approved or rejected on the basis of this assessment Aurora requires sufficient resources to prepare robust justification for the expenditure.

5 AER, Demand Management Incentive Scheme Aurora Energy, Regulatory Control period commencing 1 July 2012, October 2010, page 3.

27. Cost Pass Through – Additional Pass Through Events

27. Cost pass through – additional pass through events

27.1. Background

Chapter 10 of the *Rules* provides that any of the following is a pass through event:

- a regulatory change event;
- a service standard event;
- a tax change event; and
- a terrorism event.

The definition of "pass through event" also states that "An event nominated in a Distribution Determination as a pass through event is a pass through event for the Determination (in addition to those listed above)".

This means that Aurora is free to nominate additional events to the four specified in Chapter 10 of the *Rules* to the extent that it feels that additional events would be relevant to its specific circumstances.

Clause S6.1.3 of the *Rules* states that Aurora's Building Block Proposal must contain certain additional matters. Clause S6.1.3.2 provides that one of these must be "a proposed pass through clause with a proposal as to the events that should be defined as pass through events".

Clause 6.12.1 states that the AER's Distribution Determination must contain a number of constituent decisions. Clause 6.12.1.14 states that one of these constituent decisions is "a decision on the additional pass through events that are to apply for the *Regulatory Control Period*".

This means that Aurora is required to propose any additional pass through events that are to apply in the *Regulatory Control Period* and the AER must consider and make a constituent decision on this proposal as part of the Determination.

27.2. Additional pass through events

Aurora proposes the following additional pass through events for the forthcoming *Regulatory Control Period*:

- natural disaster event;
- bushfires event;
- storms event;
- industry restructure event;
- retailer of last resort event;
- carbon tax event;
- insurer credit risk event;
- liability above insurance cap event; and
- feed in tariff event.

Aurora understands that the AER's most recent approach for accepting pass through events is to have regard for:

- whether the event is already captured by the prescribed *Rules* event definitions;
- whether the allowance of the event would conflict with the *Rules* definitions;
- whether the nature of the event is foreseeable;
- whether the event is of a low probability but a high consequence or magnitude; and
- whether the event is beyond the control of Aurora.

Aurora's justification for each of its nominated pass through events is set out below.

27.2.1. Natural disaster event

Aurora proposes a pass through arrangement for a "natural disaster event". The definition of the natural disaster event is:

> *Any major fire, flood, earthquake, or other natural disaster beyond the control of Aurora that occurs during the Regulatory Control Period and materially increases the costs to Aurora of providing Direct Control Services.*

In support of this pass through event, Aurora notes that:

- a natural disaster pass through event is not already captured by the prescribed *Rules* event definitions;
- the allowance of a natural disaster pass through event would not conflict with the *Rules* definitions;
- a natural disaster pass through event is not foreseeable;
- a natural disaster pass through event has a low probability but a high consequence or magnitude; and
- a natural disaster pass through event is beyond the control of Aurora.

In line with the AER's final decision in Victoria, Aurora proposes that an event will be considered to materially increase costs where that event has an impact of one percent of the smoothed forecast revenue specified in the final decision in the years of the *Regulatory Control Period* that the costs are incurred.

27.2.2. Bushfire event

Aurora proposes a pass through arrangement for a "bushfire event". The definition of the bushfire event is:

> *Any bushfire beyond the control of Aurora that occurs during the Regulatory Control Period and materially increases the costs to Aurora of providing Direct Control Services.*

In support of this pass through event, Aurora notes that:

- a bushfire pass through event is not already captured by the prescribed *Rules* event definitions;
- the allowance of a bushfire pass through event would not conflict with the *Rules* definitions;
- a bushfire pass through event is not foreseeable;
- a bushfire pass through event has a low probability but a high consequence or magnitude; and
- a bushfire pass through event is beyond the control of Aurora.

Aurora proposes that an event will be considered to materially increase or decrease costs where that event has an impact of one percent of the smoothed forecast revenue specified in the final decision in the years of the *Regulatory Control Period* that the costs are incurred.

27.2.3. Storms event

Aurora proposes a pass through arrangement for a "storms event". The definition of the storm event is:

> *Any storm beyond the control of Aurora that occurs during the Regulatory Control Period and materially increases the costs to Aurora of providing Direct Control Services.*

In support of this pass through event, Aurora notes that:

- a storms pass through event is not already captured by the prescribed *Rules* event definitions;
- the allowance of a storms pass through event would not conflict with the *Rules* definitions;
- a storms pass through event is not foreseeable;
- a storms pass through event has a low probability but a high consequence or magnitude; and
- a storms pass through event is beyond the control of Aurora.

Aurora proposes that an event will be considered to materially increase or decrease costs where that event has an impact of one percent of the smoothed forecast revenue specified in the final decision in the years of the *Regulatory Control Period* that the costs are incurred.

27.2.4. Industry restructure event

The Tasmanian Government has announced a formal review into the electricity industry. The costs of any business separation are not included in this Regulatory Proposal. Aurora proposes that a specific pass through mechanism be established by the AER which would be triggered at the time the Tasmanian Government implements any future decision within the *Regulatory Control Period*.

The range of possible industry restructure event outcomes include:

- no change to the structure of Aurora. This is the basis upon which Aurora's *Regulatory Proposal* has been developed;
- separation of Aurora's distribution and energy businesses into two separate businesses. This would involve costs for Aurora distribution to establish its own unique systems and corporate overheads which would require a pass through of costs; or
- separation of Aurora's distribution and energy businesses into two separate businesses, and the subsequent merger of Aurora's distribution business with Transend to form a single network company. This would involve a range of business and system integration costs for Aurora, but it is possible that it may result in reductions in operating costs over the longer term.

The definition of the industry restructure event is:

> *An industry restructure event is any legislative or administrative act or decision to separate any business or function of Aurora in whole or in part from any other business or function of Aurora, or to combine any business or function of Aurora in whole or in part with the business unit of any other entity, which materially increases or decreases the costs to Aurora of providing Direct Control Services.*

In support of the inclusion of this pass through event, Aurora notes that:

- an industry restructure pass through event is not already captured by the prescribed *Rules* event definitions;
- the allowance of a industry restructure pass through event would not conflict with the *Rules* definitions;
- an industry restructure pass through event is not foreseeable;
- an industry restructure pass through event is likely and has a high consequence or magnitude; and
- an industry restructure pass through event is beyond the control of Aurora.

While Aurora is 100 percent owned by the Tasmanian Government, Aurora would not be materially involved in the analysis underpinning any decision by the Tasmanian Government to restructure the electricity supply industry. This is because such matters are regarded as policy by the Tasmanian Government.

While it is possible that Aurora may become involved in any analysis of costs of restructure options, precedent in other States suggests that such involvement would involve the provision of costing forecast data under scenarios, upon which Government would base elements of its decision.

Accordingly, it is not possible for Aurora to foresee either whether an industry restructure event will occur or the nature of the industry restructure event at the time of lodging its *Regulatory Proposal*. Such an event would be outside the control of Aurora and its management.

Further, the costs of such an event would potentially be of a high magnitude. Costs from separating, selling or merging businesses are often significant as such processes involve systems and resource integration.

Aurora proposes that an event will be considered to materially increase or decrease costs where that event has an impact of one percent of the smoothed forecast revenue specified in the final decision in the years of the *Regulatory Control Period* that the costs are incurred.

27.2.5. Retailer of Last Resort event

Aurora proposes a pass through arrangement for a "declared Retailer of Last Resort (ROLR) event". The definition of the ROLR event is:

> *Any event where an existing retailer for distribution customers is unable to continue to supply electricity and its customers are transferred to the declared Retailer of Last Resort that occurs during the Regulatory Control Period that materially increases the costs to Aurora of providing Direct Control Services.*

In support of this pass through event, Aurora notes that:

- a ROLR pass through event is not already captured by the prescribed *Rules* event definitions;
- the allowance of a ROLR pass through event would not conflict with the *Rules* definitions;
- a ROLR pass through event is not foreseeable;
- a ROLR pass through event has a low probability but a high consequence or magnitude; and
- a ROLR pass through event is beyond the control of Aurora.

Aurora notes that the ROLR event provided for in the NECF reforms does not have a materiality threshold and Aurora therefore proposes that no materiality provisions be imposed for this event.

27.2.6. Carbon tax event

The Australian Government has announced its intention to introduce a carbon tax on 1 July 2012. As there is uncertainty regarding likely timing and policy direction of the proposed mechanism, any increased costs that may arise from this tax are not included in this *Regulatory Proposal*. Aurora proposes that a specific pass through mechanism be established by the AER should the Australian Government implement any future decision subsequent to the AER's final Determination or within the *Regulatory Control Period*.

The definition of the carbon tax event is:

> *Any legislative or administrative act or decision to impose a price or tax upon carbon, which materially increases or decreases the costs to Aurora of providing Direct Control Services.*

In support of the inclusion of this pass through event, Aurora notes that:

- a carbon tax pass through event may already be captured by the prescribed *Rules* event definition of a tax change event;
- the allowance of a carbon tax pass through event would not conflict with the *Rules* definitions;
- a carbon tax pass through event is foreseeable, however the timing and policy direction is uncertain;
- a carbon tax pass through event is a probability, however the timing and policy direction is uncertain and the event has a high consequence or magnitude; and
- a carbon tax pass through event is beyond the control of Aurora.

It is not possible for Aurora to foresee either when a carbon tax event will occur or the nature of the carbon tax event at the time of lodging its *Regulatory Proposal*. Such an event would be outside the control of Aurora and its management. Further, the costs of such an event would potentially be of a high magnitude.

Aurora proposes that no materiality provisions be imposed for this event.

27.2.7. Insurer credit risk event

Aurora proposes a pass through arrangement for an "insurer credit risk event". This event is triggered where Aurora's insurer becomes insolvent, and Aurora is subject to higher or lower premiums than those allowed in the Distribution Determination or a higher or lower claims limit or deductible than those allowed under its insurance policy with that insurer.

The definition of the insurer credit risk event is:

> *The insolvency of a nominated insurer of Aurora, as a result of which Aurora:*
>
> (i) *incurs materially higher or lower costs for insurance premiums than those allowed for in the Distribution Determination; or*
>
> (ii) *in respect of a claim for a risk that would have been insured by Aurora's insurers, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy.*

Aurora notes that a similar pass through event was approved by the AER in its Final Determination for the Victorian Distributors in 2010.

In support of this pass through event, Aurora notes that:

- an insurer credit risk pass through event is not already captured by the prescribed *Rules* event definitions;
- the allowance of an insurer credit risk pass through event would not conflict with the *Rules* definitions;
- an insurer credit risk pass through event is not foreseeable;
- an insurer credit risk pass through event has a low probability but a high consequence or magnitude; and
- an insurer credit risk pass through event is beyond the control of Aurora.

Aurora submits that the occurrence of increased insurance premiums (or deductibles) from external insurers (where the original insurer becomes insolvent) is beyond its control of Aurora (subject to any choice that Aurora has with regard to insurance companies), and that the costs associated with higher insurance premiums are also beyond the control of Aurora (in that they cannot be mitigated).

Aurora proposes that no materiality provisions be imposed for this event.

27.2.8. Liability above insurance cap event

Aurora proposes a pass through arrangement for a "liability above insurance cap event". The definition of the liability above insurance cap event is:

> *Any event beyond the control of Aurora for which external insurance has been provided and the loss materially exceeds the policy limit, and as a result Aurora must bear the amount of that excess loss and it materially increases the costs to Aurora of providing Direct Control Services.*

In support of this pass through event, Aurora notes that:

- a liability above insurance cap pass through event is not already captured by the prescribed *Rules* event definitions;
- the allowance of a liability above insurance cap pass through event would not conflict with the *Rules* definitions;
- a liability above insurance cap pass through event is not foreseeable;
- a liability above insurance cap pass through event has a low probability but a high consequence or magnitude; and
- a liability above insurance cap pass through event is beyond the control of Aurora.

In line with the AER's final decision in Victoria, Aurora proposes that an event will be considered to materially increase costs where that event has an impact of one percent of the smoothed forecast revenue specified in the final decision in the years of the *Regulatory Control Period* that the costs are incurred.

27.2.9. Feed in tariff event

Aurora proposes a pass through arrangement for a "feed in tariff event". Currently, Aurora's energy business offers, on a voluntary basis, a net feed in tariff of 22.648 c/kWh through the Aurora net metering buyback scheme. The Tasmanian Government is considering implementing a legislated gross feed in tariff in the near future.

It is not possible to prepare a forecast of the number and value of payments that Aurora may be required to make to customers in the forthcoming *Regulatory Control Period*, partly because the level of the proposed tariff is not yet known and the rate of take-up after any such changes are implemented is unpredictable". The definition of the feed in tariff event is:

> *Any legislative or administrative act or decision to impose a feed in tariff for the production of renewable energy by Aurora's distribution customers, which increases or decreases the costs to Aurora of providing Direct Control Services.*

In support of this pass through event, Aurora notes that:

- a feed in tariff pass through event is not already captured by the prescribed *Rules* event definitions;
- the allowance of an feed in tariff pass through event would not conflict with the *Rules* definitions;
- a feed in tariff pass through event is not foreseeable;
- a feed in tariff pass through event has a low probability but a high consequence or magnitude; and
- a feed in tariff pass through event is beyond the control of Aurora.

Aurora proposes that no materiality provisions be imposed for this event. Aurora also proposes that its payments to customers be adjusted on an annual basis in conjunction with other annual adjustment requirements, and would provide the AER with evidence of the relevant payments made.

Aurora notes that clause 6.18.7A of the *Rules* allows Aurora to recover payments made under an 'approved jurisdictional scheme' (such as a feed in tariff scheme: *Rules*, clause 6.18.7A(e)). Should the AER determine, pursuant to clause 6.18.7A(l) of the *Rules*, that any feed in tariff scheme introduced by the Tasmanian Government is a jurisdictional scheme (see also *Rules*, clauses 6.6.1A(a), (e) and (f), and *Rules* chapter 10 - definition of 'approved jurisdictional scheme'), it would obviate the need for a feed in tariff pass through event.

28. Capital Contributions

28. Capital contributions

28.1. Rules requirements

Clause 6.21 of the *Rules* details the circumstances in which Aurora may minimise financial risks associated with investment in network assets and provides for adoption of cost reflective payment options in conjunction with the use of average distribution prices. In particular:

- clause 6.21.2(2) provides that Aurora may receive a capital contribution, prepayment and/or financial guarantee up to Aurora's future revenue related to the provision of *Direct Control Services* for any new assets installed as part of a new connection or modification to an existing connection, including any augmentation to the distribution network; and
- clause 6.21.2(3) provides that where assets have been the subject of a contribution or prepayment, Aurora must amend its revenue related to the provision of direct control services.

28.2. Aurora's capital contributions methodology

Aurora's Customer Capital Contributions Policy is being revised to ensure that it will provide an appropriate allocation of costs between connecting customers and users of the shared distribution network. The review will result in a customer contributions policy that reflects the efficient cost of providing new connection services and ensures greater equity between customer classes. The review will also ensure that Aurora's customer contribution policy is reflective and consistent with the distribution business' revised strategy and the intent of the NECF, which is expected to commence from 1 July 2012.

This amended policy will result in customers contributing an efficient amount for the provision of distribution services that are provided solely for the connecting customer. This policy change will result in customers contributing to their connection assets at the time of connection, rather than providing Aurora a revenue stream through the application of the customer's tariff. This policy also ensures that existing customers are not funding the dedicated connection assets of other customers through the 'shared network' tariffs.

At the time of submitting this *Regulatory Proposal*, Aurora has not completed consultation on the changes intended to apply in its new customer contributions policy. Aurora has however prepared its capital expenditure forecasts on the assumption that its proposed customer contributions policy will apply as intended.

Aurora has included its proposed customer connection policy as a confidential attachment to this *Regulatory Proposal*.

28.2.1. Gifted Assets

Aurora currently provides all construction services for the provision of its assets and therefore does not have any assets that are gifted to it by other providers, such as the developers of residential subdivisions.

28.3. Actual and estimated capital contributions for the current Regulatory Control Period

Aurora's actual and estimated capital contributions for the current *Regulatory Control Period*, are shown in Table 111.

Table 111

Aurora's current Regulatory Control Period capital contributions

$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Forecast allowance	4.099	8.198	8.198	8.198	8.198
Cash contributions	5.280	9.495	8.578	8.759	9.472
Gifted assets	-	-	-	-	-
Total	**5.280**	**9.495**	**8.578**	**8.759**	**9.472**
Variance to forecast	1.182	1.298	0.380	0.561	1.274

28.4. Forecast capital contributions for the forthcoming Regulatory Control Period

Aurora's actual and estimated capital contributions for the 2012-17 *Regulatory Control Period*, are shown in Table 112.

Table 112

Aurora's Forecast Capital Contributions

$2009-10	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Cash contributions	18.711	18.711	18.711	18.711	18.711
Gifted assets	-	-	-	-	-
Total	**18.711**	**18.711**	**18.711**	**18.711**	**18.711**

28.5. Allocating capital contributions to asset classes

When Aurora constructs assets that are funded by cash contributions, it separates them into the relevant asset categories in its asset register. These assets are in turn reflected into the different asset classes of Aurora's RAB, which is used for the purposes of the AER's RFM and the PTRM.

28.6. Adjustments to revenues to recognise capital contributions

As discussed above, Aurora does not fully fund assets that relate to capital contributions. Rather, they are funded by a cash payment to Aurora from customers or developers.

As Aurora includes the value of all assets funded by capital contributions in its RAB, there is a need to reduce Aurora's revenues in order to ensure that it does not recover the value of the capital contribution twice.

Aurora deals with this matter by:

- incorporating the full construction cost of the assets into its RAB in the Regulatory Year in which the capital contribution is received; and
- also deducting the full value of the capital contribution from Aurora's RAB in the Regulatory Year in which the capital contribution is received.

This treatment results in only the net value of assets being included in Aurora's RAB. This can be expressed as:

(construction cost) – (capital contribution) = (net asset value).

As assets that are funded by customer contributions are included in Aurora's RAB at net value (full funded assets will have a nil net value), Aurora does not receive additional revenues from these assets in the application of the AER's RFM and PTRM.

29. X Factor

29. X Factor

29. X factor

Clause 6.5.9(a) states that "A Building Block Determination is to include the X factor for each control mechanism for each *Regulatory Year* of the *Regulatory Control Period*".

Clause 6.5.9(b) states that the X factor:

(1) must be set by the AER with regard to Aurora's total revenue requirement for the *Regulatory Control Period*; and

(2) must be such as to minimise, as far as reasonably possible, variance between expected revenue for the last *Regulatory Year* of the *Regulatory Control Period* and the annual revenue requirement for that last *Regulatory Year*; and

(3) must conform with whichever of the following requirements is applicable:

  (i) if the control mechanism relates generally to *Standard Control Services* – the X factor must be designed to equalise (in terms of net present value) the revenue to be earned by Aurora from the provision of *Standard Control Services* over the *Regulatory Control Period* with Aurora's total revenue requirement for the *Regulatory Control Period*;

  (ii) if there are separate control mechanisms for different *Standard Control Services* – the X factor for each control mechanism must be designed to equalise (in terms of net present value) the revenue to be earned by Aurora from the provision of *Standard Control Services* to which the control mechanism relates over the *Regulatory Control Period* with the portion of the provider's total revenue requirement for the *Regulatory Control Period* attributable to those services.

Aurora has not varied the ordinary operation of the AER's PTRM and has used the formula included in the PTRM to establish the X factors for *Standard Control Services*. In accordance with clause 6.5.9(b)(3)(i), it has designed its X factor to equalise (in terms of net present value) the revenue to be earned from the provision of *Standard Control Services* over the *Regulatory Control Period* with the Aurora's total revenue requirement for the *Regulatory Control Period*.

In accordance with clause 6.5.9(b)(2), Aurora has minimised, as far as reasonably possible, the variance between expected revenue for the last Regulatory Year of the *Regulatory Control Period* and the annual revenue requirement for that last Regulatory Year. The variance is 0.00 percent.

The resulting X factors for each year of the *Regulatory Control Period* are set out in Table 113.

Table 113

X Factors

	2012-13	2013-14	2014-15	2015-16	2016-17
X factor (%)	10.69	(0.12)	(0.12)	(0.12)	(0.12)

The application of these X factors results in the smoothed revenue requirement for the *Regulatory Control Period* as set out in Table 114.

Table 114

Smoothed Revenue Outcomes

Nominal dollars	Total NPV ($m)	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Adjusted notional Revenue	1,149.43	287.39	303.48	310.27	313.45	323.35
Smoothing		5.14	(3.76)	(3.19)	1.18	0.01
Smoothed building block revenue	1,149.43	292.53	299.72	307.09	314.63	322.36
Variance		1.8%	(1.2%)	(1.0%)	0.4%	0.0%

30. Annual Revenue Requirement

30. Annual revenue requirement

30.1 Rules requirements

Clause 6.3.2(a)(1) of the *Rules* requires the AER to specify in its Building Block Determination Aurora's annual revenue requirement (ARR) for each Regulatory Year of the forthcoming *Regulatory Control Period*.

Clause 6.12.1(2)(i) of the *Rules* provides that one of the constituent decisions of the AER's Distribution Determination is whether to approve, or not to approve, the ARR for each Regulatory Year of the *Regulatory Control Period*, as set out in the Aurora's building block proposal.

In accordance with clause 6.4.2(a) of the *Rules*, the PTRM sets out the manner in which Aurora's ARR for each Regulatory Year of the forthcoming *Regulatory Control Period* is to be calculated.

Clause 6.12.3(d) of the *Rules* provides that the AER must approve Aurora's ARR for each Regulatory Year of the forthcoming *Regulatory Control Period*, as set out in Aurora's Building Block Proposal, if the AER is satisfied that the amounts have been calculated using the PTRM on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of Chapter 6 of the *Rules*.

Clause 6.4.3(a) of the *Rules* provides that Aurora's ARR for each Regulatory Year of the forthcoming *Regulatory Control Period* must be calculated using a building block approach, under which the building blocks are:

- the indexation of the RAB, calculated in accordance with clause 6.4.3(b)(1) of the *Rules*;
- a return on capital for that Regulatory Year, calculated in accordance with clause 6.4.3(b)(2) of the *Rules*;
- the depreciation for that Regulatory Year, calculated in accordance with clause 6.4.3(b)(3) of the *Rules*;
- the estimated cost of corporate income tax for that Regulatory Year, calculated in accordance with clause 6.4.3(b)(4) of the *Rules*;
- the revenue increments or decrements (if any) for that Regulatory Year arising from the application of the EBSS, STPIS and DMIS, calculated in accordance with clause 6.4.3(b)(5) of the *Rules*;
- the other revenue increments or decrements (if any) for that Regulatory Year arising from the application of a control mechanism in the current *Regulatory Control Period*, calculated in accordance with clause 6.4.3(b)(6) of the *Rules*; and
- the forecast operating expenditure for that Regulatory Year, calculated in accordance with clause 6.4.3(b)(7) of the *Rules*.

30.2 Aurora's ARR

Aurora confirms that it has prepared its ARR for each Regulatory Year of the forthcoming *Regulatory Control Period* in accordance with the requirements of Part C of Chapter 6 of the *Rules*, in particular by applying the:

- PTRM established by the AER under clause 6.4 of the *Rules*; and
- building block approach provided for by clause 6.4.3 of the *Rules*.

Aurora has provided a completed PTRM and a completed RFM to the AER with this *Regulatory Proposal*. Aurora's demonstration of the application of the models in calculating the ARR, including the assumptions it has made in populating the models, are shown in the models or this *Regulatory Proposal*.

Aurora's ARR (smoothed) for the 2012-17 *Regulatory Control Period* is shown in Table 115.

Table 115

Annual Revenue Requirement

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Annual smoothed revenue	292.53	299.72	307.09	314.63	322.36

The building blocks that comprise the ARR are discussed in the following sections.

30.2.1 Establishing the RAB

Aurora has been required to make a number of adjustments to the 1 January 2008 RAB value of $981.108 million (July 2006 dollars) specified in schedule 6.2.1(c)(1) of the *Rules*. Aurora's opening RAB for each year requiring an adjustment is shown in Table 116.

Table 116

Opening Regulatory Asset Base

Nominal dollars	2006-07 ($m)	2007-08 ($m)	2008-09 ($m)	2009-10 ($m)	2010-11 ($m)	2011-12 ($m)
Opening RAB – 1 July	908.20	984.14	1,072.22	1,156.57	1,266.62	1,384.85

Aurora has calculated the proposed opening RAB for the 2012-17 *Regulatory Control Period* by applying the methodology set out in schedule 6.2 of the *Rules* and the AER's RFM. A detailed explanation of the basis of Aurora's calculation is provided in chapter 19 of this *Regulatory Proposal*.

30.2.2. Indexation of the RAB

Aurora's proposed opening RAB for *Standard Control Services* for each Regulatory Year of the 2012-17 *Regulatory Control Period* is shown in Table 117.

Table 117

Opening Regulatory Asset Base

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Opening RAB – 1 July	1,484.86	1,572.70	1,659.18	1,747.16	1,840.51

Aurora has calculated the proposed opening RAB for each Regulatory Year of the 2012-17 *Regulatory Control Period* by applying the AER's RFM. A detailed explanation of the basis of Aurora's calculation is provided in chapter 19 of this *Regulatory Proposal*.

As required by clause 6.4.2(b)(1) of the *Rules*, Aurora has indexed its RAB utilising its best estimates of expected inflation:

- from the current *Regulatory Control Period* to the beginning of the first Regulatory Year of the forthcoming *Regulatory Control Period*, in accordance with clause 6.5.1(e)(3) of the *Rules*; and
- between each Regulatory Year of the forthcoming *Regulatory Control Period*.

Aurora has applied the AER's preferred methodology for calculating actual inflation and the Reserve Bank of Australia's (RBA) February 2011 Statement on Monetary Policy forecasts for 2010-11 and 2011-12 annual inflation for indexation of the RAB for the current *Regulatory Control Period*. For the 2012-17 *Regulatory Control Period*, Aurora has proposed an annual inflation rate of 2.58 percent.

An explanation of the basis of the calculation of annual inflation in the forthcoming *Regulatory Control Period* is provided in chapter 7 of this *Regulatory Proposal*.

30.2.3. Return on capital

Aurora's proposed return on capital for *Standard Control Services* for each Regulatory Year of the 2012-17 *Regulatory Control Period* is shown in Table 118.

Table 118

Return on capital

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Return on capital	149.59	158.44	167.16	176.02	185.42

In accordance with clause 6.5.2(b) of the *Rules*, the rate of return is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Aurora.

Aurora has calculated the proposed return on capital for each Regulatory Year of the 2012-17 *Regulatory Control Period* by applying the AER's PTRM. Aurora has determined the proposed return on capital by applying a rate of return to the value of the RAB as at the beginning of the Regulatory Year in accordance with clause 6.5.2(a) of the *Rules*.

A detailed explanation of the basis of the calculation of the rate of return on capital is provided in chapter 20 of this *Regulatory Proposal*.

30.2.4. Regulatory depreciation

Aurora's proposed regulatory depreciation for *Standard Control Services* for each Regulatory Year of the 2012-17 *Regulatory Control Period* is shown in Table 119.

Table 119

Regulatory depreciation

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Return of capital (regulatory depreciation)	46.05	52.28	49.25	42.33	41.93

Aurora has calculated the proposed regulatory depreciation for each Regulatory Year of the 2012-17 *Regulatory Control Period* by applying the AER's PTRM and RFM.

In accordance with clause 6.5.5(a) of the *Rules*, Aurora has determined the proposed regulatory depreciation for each Regulatory Year of the 2012-17 *Regulatory Control Period*:

- based on the value of the assets as included in the RAB, as at the beginning of the Regulatory Year; and
- by preparing regulatory depreciation schedules that conform with the requirements of clause 6.5.5(b) of the *Rules*.

A detailed explanation of the basis of the calculation of the regulatory depreciation is provided in chapter 22 of this *Regulatory Proposal*.

30.2.5 Corporate income tax

Aurora's estimated cost of corporate income tax for *Standard Control Services* for each Regulatory Year of the 2012-17 *Regulatory Control Period* is shown in Table 120.

Table 120

Corporate income tax

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Benchmark tax liability	14.17	15.36	15.12	15.22	15.36

A detailed explanation of the basis of the estimation of Aurora's corporate income tax is provided in chapter 22 of this *Regulatory Proposal*.

30.2.6. Revenue increments and decrements arising from schemes

Clause 6.4.3(a)(5) of the *Rules* requires the ARR for each Regulatory Year of a *Regulatory Control Period* to include the revenue increments or decrements (if any) for that Regulatory Year arising from the application of the EBSS, STPIS and DMIS, calculated in accordance with clause 6.4.3(b)(5) of the *Rules*.

Aurora considers that:

- there will be no revenue increments or decrements arising from the EBSS for any Regulatory Year of the 2012-17 *Regulatory Control Period*, due to the lagged effect of the scheme. Any increments or decrements arising under the EBSS, attributable to operating expenditure incurred during the 2012-17 *Regulatory Control Period*, will be reflected in the calculation of the annual revenue requirements for the *Regulatory Control Period* commencing on 1 July 2017. The EBSS is discussed further in chapter 24 of this *Regulatory Proposal*;
- the value of any revenue increments or decrements arising under the STPIS for any Regulatory Year of the 2012-17 *Regulatory Control Period* cannot be forecast in this *Regulatory Proposal*. They will only become known during the course of the forthcoming *Regulatory Control Period* when Aurora's performance against the performance parameters is known. The STPIS is discussed further in chapter 25 of this *Regulatory Proposal*;
- STPIS related revenue increments and decrements will be treated as adjustments to the ARR for the relevant Regulatory Year. This is discussed further at section 32.5.7 of this *Regulatory Proposal*; and
- Aurora has included a revenue increment of $2 million over the course of the 2012-17 *Regulatory Control Period* for the DMIA allowed under the DMIS. However, any carryover amount arising from the DMIS will only be applied in the calculation of the ARR for the second Regulatory Year in the *Regulatory Control Period* commencing on 1 July 2017. The DMIA and DMIS are discussed further in chapter 26 of this *Regulatory Proposal*.

30.2.7. Other revenue increments and decrements

Clause 6.4.3(a)(6) of the Rules requires the ARR for each Regulatory Year of a *Regulatory Control Period* to include other revenue increments or decrements arising from the application of a control mechanism in the current *Regulatory Control Period*.

Aurora's revenue increments or decrements arising from application of a control mechanism in the current *Regulatory Control Period* are not known due to the lagged effect of these adjustments. Any increments or decrements arising from the application of a control mechanism in the current *Regulatory Control Period* will be reflected into the calculation of the annual revenue requirement for the forthcoming *Regulatory Control Period*.

Aurora will adjust its ARR for each Regulatory Year of the 2012-17 *Regulatory Control Period* following the submission of Aurora's ring-fenced accounts to OTTER for the following matters relating to the current *Regulatory Control Period*:

- previous under- or over-recovery of revenue;
- differences in the electrical safety inspection levy imposed in accordance with section 121B of the ESI Act;
- differences in the national energy market charge levied in accordance with section 121 of the ESI Act;
- the impact on the ARR of differences between the actual and forecast allowance relating to Aurora's participation in the NEM and retail contestability costs;
- differences between the actual and forecast allowance relating to Aurora's payments for the State Government's trunk mobile radio network;
- an allowance attributable to the implementation of full retail competition that is approved by OTTER;
- an allowable tax event consistent with Regulation 31(4) of the Price Control Regulations;
- an allowance attributable to changes in safety and/or environmental legislation that is approved by OTTER;
- changes in Aurora's capital contributions policy;
- differences between the actual and forecast allowance relating to Aurora's total GSL payments; and
- adjustments arising from the making of single duration GSL payments where the threshold payment is adjusted in accordance with the methodology approved by OTTER.

30.2.8. Operating expenditure

Aurora's forecast operating expenditure for *Standard Control Services* for each Regulatory Year of the 2012-17 *Regulatory Control Period* is shown in Table 121.

Table 121

Operating Expenditure

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)
Operating expenditure	77.58	77.40	78.75	79.87	79.64

Aurora has forecast operating expenditure for each regulatory year of the forthcoming regulatory control period and applies this in the AER's PTRM.

The forecast operating expenditure is that which is required by Aurora to achieve each of the operating expenditure objectives in clause 6.5.6(a) of the *Rules* for the provision of *Standard Control Services*.

A detailed explanation of the basis of Aurora's operating expenditure forecast is provided in chapter 12 of this *Regulatory Proposal*.

30.2.9. Annual revenue requirement

Aurora's ARR, showing all the building blocks, for *Standard Control Services* for the 2012-17 *Regulatory Control Period* is shown in Table 122.

Table 122

Annual revenue requirement

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)	Total NPV ($m)
Return on capital	149.59	158.44	167.16	176.02	185.42	
Return of capital (regulatory depreciation)	46.05	52.28	49.25	42.33	41.93	
Operating expenditure	77.58	77.40	78.75	79.87	79.64	
Benchmark tax liability	14.17	15.36	15.12	15.22	15.36	
Notional building block revenue	287.39	303.48	310.27	313.45	322.35	1,149.43
Notional building block smoothed revenue	292.53	299.72	307.09	314.63	322.36	1,149.43

31. Total Revenue Requirement

31. Total revenue requirement

31.1. Rules requirements

Chapter 10 of the *Rules* defines the total revenue requirement as:

> *For a Distribution Network Service Provider, an amount representing revenue calculated for the whole of a Regulatory Control Period in accordance with Part C of Chapter 6.*

The total revenue requirement for the 2012-17 *Regulatory Control Period* is therefore calculated as the summation of the ARR for each Regulatory Year of that *Regulatory Control Period*.

Aurora notes that clause 6.12.3(d) of the *Rules* provides that the AER must approve the total revenue requirement set out in Aurora's building block proposal if it is satisfied that the amount has been properly calculated using the PTRM on the basis of amounts calculated, determined or forecast in accordance with the requirements of the *Rules* Chapter 6, Part C.

31.2. Aurora's total revenue requirement

Aurora's proposed total ARR for the 2012-17 *Regulatory Control Period* is $1,536.33 million. The ARR for each year of the forthcoming *Regulatory Control Period* is shown in Table 123.

Table 123

Total revenue requirement

Nominal dollars	2012-13 ($m)	2013-14 ($m)	2014-15 ($m)	2015-16 ($m)	2016-17 ($m)	TOTAL ($m)	Average ARR ($m)
Annual revenue requirement (smoothed)	292.53	299.72	307.09	314.63	322.36	1,536.33	307.27

Aurora confirms that it has prepared its total revenue requirement for the 2012-17 *Regulatory Control Period* in accordance with the requirements of Part C of Chapter 6 of the *Rules*, in particular by applying:

- the PTRM established by the AER under clause 6.4 of the *Rules*; and
- the building block approach provided for by clause 6.4.3 of the *Rules*.

Aurora has provided a completed PTRM and a completed roll forward model to the AER with this *Regulatory Proposal*. Aurora's demonstration of the application of the models in calculating the Total Revenue Requirement, including the assumptions it has made in populating the models, are shown in the models.

32. Control Mechanisms for Standard Control Services

32. Control mechanisms for Standard Control Services

32.1. Overview

This Chapter sets out the:

- control mechanism to apply to *Standard Control Services* over the forthcoming *Regulatory Control Period*; and
- the variations to that control mechanism that have been identified as needing to be implemented over the forthcoming *Regulatory Control Period*.

32.2. The AER's Framework and Approach

Clause 6.8.1(a) of the *Rules* requires the AER to prepare and publish a Framework and Approach paper in anticipation of each Distribution Determination, which is to state the form or forms of the control mechanisms to be applied by the Distribution Determination and the AER's reasons for deciding on control mechanisms of the relevant form or forms (clause 6.8.1(c) of the *Rules*).

Clause 6.2.6(a) of the *Rules* specifies that, for *Standard Control Services*, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C of Chapter 6 of the *Rules*.

Clause 6.12.3(c) of the *Rules* provides that the control mechanisms in a Distribution Determination must be as set out in the relevant Framework and Approach paper.

In accordance with the above provisions, the AER published its final Framework and Approach on 29 November 2010. Consistent with the above provisions, the AER stated[1] that:

> *The AER will apply a revenue cap to the services classified in chapter 2 as Standard Control Services in the forthcoming Regulatory Control Period with a basis of the CPI–X form.*

1 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 84.

In addition to this, the AER considered a number of adjustment mechanisms to be applied to the fixed revenue cap during the forthcoming *Regulatory Control Period*. Specifically, the AER referred to the GSL Scheme, STPIS, EBSS and DMIS.

32.3. Adjustments

Once approved by the AER, Aurora's control mechanism for *Standard Control Services* will allow for annual increases or decreases in Aurora's ARR as a consequence of a number of revenue adjustment factors which will be calculated annually. These revenue adjustment factors were agreed with the OTTER at the commencement of the current *Regulatory Control Period* and will continue into the forthcoming *Regulatory Control Periods*.

Chapter 6 of the *Rules* allows for these revenue adjustment factors to continue beyond the end of one *Regulatory Control Period* and into the forthcoming *Regulatory Control Period*.

Clause 6.4.3(a)(6) of the *Rules* allows for the building blocks to include:

- the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous *Regulatory Control Period* – see paragraph (b)(6).

Clause 6.4.3(b)(6) of the *Rules* states that for the purposes of the above:

- the other revenue increments or decrements referred to in paragraph (a)(6) are those that are to be carried forward to the current *Regulatory Control Period* as a result of the application of a control mechanism in the previous *Regulatory Control Period* and are apportioned to the relevant year under the Distribution Determination for the current *Regulatory Control Period*.

Aurora submits that:

- the control mechanism established by OTTER for the current *Regulatory Control Period* allowed for annual adjustments to the AARR for a number of revenue adjustment factors. These are not change events or pass-throughs; they are annual revenue adjustments based on defined events that formed a transparently identified component of the control mechanism formula. These are set out transparently in OTTER's 2007 Pricing Determination[2];
- this control mechanism was clearly intended to operate beyond the end of the currently *Regulatory Control Period*; and
- the control mechanism for *Standard Control Services* for the forthcoming *Regulatory Control Period* should be adjusted for the revenue adjustments set out in this chapter. The nature of the proposed control mechanism for *Standard Control Services* is set out in chapter 6 of this *Regulatory Proposal*.

This chapter outlines the basis and calculation methods for the annual revenue adjustments that will form part of Aurora's control mechanism for *Standard Control Services*. These revenue adjustments are:

- under/over recoveries from prior period revenues;
- electrical safety inspection service levy;
- national energy market levy;
- trunk mobile radio;
- excess GSL costs; and
- NEM and retail contestability related costs.

Each of the above revenue adjustments is described below.

32.3.1. Under/over recoveries from prior period revenues

As discussed at section 5.4 of this *Regulatory Proposal*, under the revenue cap control mechanism outlined in OTTER's 2007 Pricing Determination, there is an adjustment for the surplus or shortfall of actual revenue compared to the revenue target each year. The quantum of any unders or overs variance is assessed as part of the allowable revenue calculation for each Regulatory Year. This variance is generally cleared two years after its occurrence.

Adjustments to determine the revenue to be collected in any year to account for any under or over recoveries` in the period 2 years previous will be required. For the 2012-17 *Regulatory Control Period*, Aurora's *Standard Control Services* will continue to be under a revenue cap form of control mechanism. Aurora considers that the continuation of this revenue adjustment is consistent with clause 6.4.3(b)(6) of the *Rules* and should form part of the control mechanism for *Standard Control Services* for the 2012-17 *Regulatory Control Period*.

A worked example of Aurora's proposed methodology for under/over recoveries is appended as an attachment to this *Regulatory Proposal*.

2 Investigation into Electricity Supply Industry Pricing Policies, Declared Electrical Services Pricing Determination, 31 October 2007, page 13.

32.3.2. Electrical safety inspection service levy

Workplace Standards Tasmania (WST) has responsibility for providing electrical inspection service for work beyond the point of supply to customers in accordance with the *Electricity Industry Safety and Administration Act 1997* (EIS&A Act).

In June 2007, the Tasmanian Government amended the ESI Act to impose a levy to fund electrical safety inspection services with an effective date of 1 January 2008. The electrical safety inspection service charge, as defined in the *Electricity Supply Industry Amendment Act 2007* (ESIA Act), is[3]:

> *"..an annual charge, payable to the Crown by an electricity entity for the operation and administration of the electrical safety inspection service administered by the responsible Department.."*

The amount of the levy is determined by WST and has been treated as a revenue adjustment through in the current *Regulatory Control Period*. In this regard, OTTER provided for an adjustment within the 2007 Pricing Determination to recognise the actual charge as part of the annual revenue requirement.

Aurora considers that the continuation of this revenue adjustment is consistent with Clause 6.4.3(b)(6) of the *Rules* and that it should form part of the control mechanism for *Standard Control Services* for the 2012-17 *Regulatory Control Period*.

A worked example of Aurora's proposed methodology for the electrical safety inspection levy is appended as an attachment to this *Regulatory Proposal*.

32.3.3. National energy market charge

Under the Australian Energy Market Agreement, which committed governments to the establishment of the AER and AEMC, the Commonwealth Government funds the AER and the States and Territories fund the AEMC. The agreement allows the States and Territories to recover, from the industry, the cost of funding the AEMC. The ESI Act provides for the Crown to recover from an electricity entity, in each financial year[4] :

> *"… a charge representing part or all of the cost of the State's funding commitments in respect of the AEMC."*

The Minister for Energy notifies Aurora of the amount of the charge each financial year. Under the OTTER 2007 Pricing Determination, this charge was treated as an addition to the AARR within the control mechanism.

Aurora considers that the continuation of this revenue adjustment is consistent with clause 6.4.3(b)(6) of the *Rules* and that it should form part of the control mechanism for *Standard Control Services* for the 2012-17 *Regulatory Control Period*.

A worked example of Aurora's proposed methodology for the national energy market levy is appended as an attachment to this *Regulatory Proposal*.

3 Section 121B(1).

4 Section 121(1).

32.3.4. Trunk mobile radio

Aurora contributes to a joint government department cost of running the trunk mobile radio (TMR) network within Tasmania for emergency services. This charge is levied upon Aurora by the Police and Emergency Management Department each financial year. In OTTER's 2007 pricing determination it was flagged that Government was considering pursuing a TMR system to service all Tasmanian Government agencies. However, arrangements surrounding the provision of this service to all Tasmanian Government agencies have yet to be finalised and costs for the provision of this service still remain uncertain.

Under the OTTER 2007 Pricing Determination, the existing charge was treated as an addition to the AARR within the control mechanism.

Aurora considers that the continuation of this revenue adjustment is consistent with clause 6.4.3(b)(6) of the *Rules* and that it should form part of the control mechanism for *Standard Control Services* for the 2012-17 *Regulatory Control Period*.

A worked example of Aurora's proposed methodology for trunk mobile radio is appended as an attachment to this *Regulatory Proposal*.

32.3.5. Excess GSL costs

In OTTER's 2007 pricing determination, two adjustment mechanisms were included to deal with the risks associated with Aurora paying customers an amount for GSL payments materially higher than expected. The two mechanisms adopted that provide this risk sharing mechanism to both Aurora and its customers are:

- GSL payments are capped at 2 times the cumulative GSL allowance provided for in the 2007 Distribution Determination. Any cumulative expenditure in excess of the cumulative allowances is recoverable from tariffs in the following year; and
- Where there are widespread outages, thresholds for the single outage duration GSL payments will be calculated after the event. If the event results in more than 34,000 customers experiencing an outage in a 24 hour period then the adjusted thresholds will be calculated in accordance with the following formula:

  Adjusted threshold = $\boldsymbol{x}$**(number of customers affected/34,000)*

  Where $\boldsymbol{x}$ *is the standard threshold*[5]

Aurora will continue to make payments to all eligible customers according to unadjusted thresholds with half of all payments made to customers below the adjusted threshold recoverable through tariffs in the following year. The remaining half will contribute to calculations of whether Aurora has reached the cap for payments over the period.

Aurora considers that the continuation of this revenue adjustment is consistent with clause 6.4.3(b)(6) of the *Rules* and that it should form part of the control mechanism for *Standard Control Services* for the 2012-17 *Regulatory Control Period*.

A worked example of Aurora's proposed methodology for excess GSL costs is appended as an attachment to this *Regulatory Proposal*.

32.3.6. NEM and retail contestability related costs

Tasmania's entry to the NEM has been progressively introduced since May 2005. The approach has been staged with the introduction of contestability tranches from 1 July 2006.

Table 124

Contestability tranches

Tranche	Commencement Date	Number of Installations
Tranche 1	1 July 2006	19
Tranche 2	1 July 2007	41
Tranche 3	1 July 2008	293
Tranche 4	1 July 2009	1,233
Tranche 5A	1 July 2011	(approx) 4,000
Full retail contestability	Yet to be announced	(approx) 250,000

In OTTER's 2007 Distribution Determination, 'NEM participation' operating costs were recognised as necessary for Aurora to act as a DNSP and subsequently treated as a revenue adjustment. Given the uncertainty of costs associated with full retail contestability and whether the decision to proceed with FRC would be made, OTTER also provided for an adjustment to be made to accommodate any necessary costs arising from the Governments decision within the 2007 Pricing Determination.

The decision on FRC is still with the Government, with no indication of likely commencement or timing. Given the uncertainty surrounding a Government decision on this matter, Aurora proposes that OTTER's approach to the NEM participation and FRC costs is adopted for the 2012-17 *Regulatory Control Period*.

Aurora considers that the continuation of this revenue adjustment is consistent with clause 6.4.3(b)(6) of the *Rules* and that it should form part of the control mechanism for *Standard Control Services* for the 2012-17 *Regulatory Control Period*.

A worked example of Aurora's proposed methodology for NEM and retail contestability costs is appended as an attachment to this *Regulatory Proposal*.

5 Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Final Report and Proposed Maximum Prices, September 2007, Table 12.3.

32.3.7. Application of various schemes to Aurora

STPIS

In the Framework and Approach, the AER noted[6] that the application of a STPIS would provide appropriate incentives for Aurora to maintain and improve service performance, and that the AER intends[7] to apply a STPIS to Aurora (albeit retaining the jurisdictional GSL Scheme rather than using the GSL component of the STPIS).

The STPIS aims[8] to ensure that the DNSP achieves, or maintains, efficient service levels so that the incentive to minimise operational expenditure does not result in lower levels of service for customers, specifically by requiring Aurora to make penalty payments to customers when service performance falls below a certain standard (and vice versa).[9] Further information on the STPIS is set out in chapter 25 of this *Regulatory Proposal*.

Should the AER decide to apply a STPIS to Aurora in the forthcoming *Regulatory Control Period*, then any revenue increment or decrement associated with the operation of that STPIS in a Regulatory Year will be applied to the smoothed ARR that applies two Regulatory Years after the Regulatory Year in which the service performance was measured.

EBSS

In the Framework and Approach, the AER noted[10] that the EBSS would apply to Aurora's operational expenditure.

The EBSS creates incentives on Aurora to realise operational efficiency gains, essentially by providing for a fair sharing between Aurora and Aurora's customers of:

- the efficiency gains derived from Aurora's operating expenditure for a *Regulatory Control Period* being less than; and
- the efficiency losses derived from Aurora's operating expenditure for a *Regulatory Control Period* being more than;

the forecast operating expenditure accepted or substituted by the AER for that *Regulatory Control Period*. Further information on the EBSS is set out in chapter 24 of this *Regulatory Proposal*.

The AER also noted[11] that the application of positive and negative carryovers was important for the continuity of incentives.

Accordingly, any applicable EBSS revenue increment or decrement will be added to operating expenditure, and the AER will apply both positive and negative carryovers as part of the operating expenditure building block element in the calculation of Aurora's ARR for the *Regulatory Control Period* following the *Regulatory Control Period* in which the EBSS applied (i.e., the 2017-22 *Regulatory Control Period*).[12]

DMIS

A DMIS is intended to provide incentives for Aurora to implement efficient non-network alternatives or to manage the expected demand for *Standard Control Services* in some other way. This can have positive impacts by reducing inefficient peaks and encouraging more efficient use of existing network assets, resulting in lower prices for network users.

The DMIS proposed by the AER to apply to Aurora[13] allows for the recovery of costs for demand management projects and programs undertaken throughout the *Regulatory Control Period*, subject to the satisfaction of a defined criterion. The Demand Management Incentive Allowance (DMIA) is provided as a capped, annual ex ante allowance which is subject to a single adjustment in the subsequent *Regulatory Control Period* to return to customers any expenditure not approved or not spent. Further information on the DMIS is set out in Chapter 26 of this *Regulatory Proposal*.

Accordingly, should the AER apply a DMIS to Aurora in the forthcoming *Regulatory Control Period*, any DMIA (up to a maximum of $400,000 for each year of the *Regulatory Control Period* (being $2 million overall)[14]) will be provided as an amount in addition to the approved efficient operating expenditure. At the end of that *Regulatory Control Period*, the AER will calculate a carryover amount to be applied to the allowed revenues in the second year of the following *Regulatory Control Period* (or as specified in the applicable DMIS).

Tasmanian Electricity Code GSL Scheme

The GSL Scheme requires that payments are made to eligible customers when they do not receive the relevant guaranteed level of distribution service. The GSL Scheme sets out the value of payments that are to be made to customers on the basis of the number of outages in any 12 month period, and on the basis of the duration, in hours, of a single outage.

The expiry of the OTTER 2007 Determination (which implements the single event safety net and risk sharing mechanism) will result in a potentially uncapped liability for Aurora.[15] The GSL Scheme can therefore impose a significant financial burden upon Aurora where interruptions to supply in Aurora's network exceed these limits.

Accordingly, to the extent that actual GSL payments differ from the forecast payments, these differences will need to be reflected in the allowed revenues as part of the annual adjustments.

Aurora's proposed mechanism for GSL Scheme payments is discussed further in chapter 23 of this *Regulatory Proposal*.

6 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 65.
7 Ibid. page VI.
8 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 117.
9 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 66.
10 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 122.
11 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 126.
12 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page V.
13 AER, Demand Management Incentive Scheme Aurora Energy, Regulatory Control period commencing 1 July 2012, October 2010.
14 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page VI.
15 Ibid. page 113.

32.3.8. Pass through events

Clause 6.6.1 of the *Rules* permits Aurora to apply for any cost pass throughs for events that materially increase or decrease the costs of providing *Direct Control Services* (including *Standard Control Services*).

These events are prescribed in the *Rules* as a regulatory change event, a service standard event, tax change event and a terrorism event.

In chapter 27 of this *Regulatory Proposal*, Aurora also proposes a number of additional pass through events, being:

- natural disaster event;
- bushfires event;
- storms event;
- industry restructure event;
- retailer of last resort event;
- carbon tax event;
- insurer credit risk event;
- liability above insurance cap event; and
- feed in tariff event.

Please refer to section 27.2 of this *Regulatory Proposal* for details of these additional pass through events.

Unfunded shared network events

Where a new large customer seeks to be supplied from Aurora's distribution system, this often requires both the construction of new connection assets and a need to augment the existing network. Both of these aspects have been classified as *Standard Control Services* by the AER. Accordingly, Aurora bears the risk in relation to the nature, timing and cost of carrying out these works.

To the extent that a significant new project takes place during a *Regulatory Control Period* which was not known about at the time of preparing the *Regulatory Proposal*, a mechanism is required to:

- recover the cost of connection assets from the particular large customer; and
- recover the cost of augmentation from all customers who use the shared network assets.

Aurora's capital expenditure forecasts for *Standard Control Services* do not provide for these costs. Accordingly, Aurora proposes that it be able to amend its revenue cap on an ex post basis to allow a return on, and of, any such new assets.

Side constraints

Aurora proposes that any revenue adjustment associated with under or over recovery of revenue, or shared asset usage, not be subject to the side constraints on tariffs provided for under clause 6.18.6 of the *Rules*. Instead, Aurora proposes that these adjustments be cleared in the following manner:

- under or over recovery of revenue be cleared over two Regulatory Years, consistent with OTTER's treatment of unders or overs; and
- shared asset usage be cleared in a single Regulatory Year, consistent with the AER's treatment of Transmission Use of System unders and overs.

32.4. Proposal for assigning customers to tariff classes

Clause 6.12.1(17) of the Rules states that a Distribution Determination is predicated on a decision by the AER on, amongst other things, the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another, including any applicable restrictions.

Clause 6.18.4 of the Rules sets out principles governing the assignment or re-assignment of customers to tariff classes and requires the Distribution Determination to contain provisions for the assessment and review of the assignment or re-assignment of customers to tariff classes and the basis on which a customer is charged. It states that:

(a) In formulating provisions of a distribution determination governing the assignment of customers to tariff classes or the reassignment of customers from one tariff class to another, the AER must have regard to the following principles:

  (1) customers should be assigned to tariff classes on the basis of one or more of the following factors:

    (i) the nature and extent of their usage;

    (ii) the nature of their connection to the network;

    (iii) whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement;

  (2) customers with a similar connection and usage profile should be treated on an equal basis;

  (3) however, customers with micro-generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile;

  (4) a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another, should be subject to an effective system of assessment and review.

(b) If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.

With respect to clause 6.18.4(a)(1) and 6.18.4(a)(2) of the *Rules*, Aurora assigns customers to tariffs on the basis of usage and size.

Customers are assigned into one of four classes of network users, namely:

- individually calculated customers;
- greater than 2MVA customers;
- standard customers; and
- embedded generators.

Aurora selects the network users for inclusion in any particular network user class.

32.4.1. Individually calculated customers

Individually calculated customers (ICCs) are those customers where:

- a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network; or
- there are only two or three customers in a supply system making average prices inappropriate; or
- a customer is connected at or close to a transmission connection point and the inclusion of average shared network costs would increase their network price above stand-alone.

ICC tariffs are based on:

- the actual dedicated connection assets utilised by the customer; plus
- the customer's specifically identified portion of any shared distribution network utilised for the electricity supply.

32.4.2. Greater than 2MVA customers

Greater than 2MVA customers (>2MVA) are those customers with an any time maximum demand that is greater than 2MVA.

>2MVA tariffs are based on:

- average charges for dedicated HV connection assets; plus
- average charges for use of the shared HV network.

32.4.3. Standard customers

All other customers (other than embedded generators) are classified as standard customers.

Standard customer tariffs are based on:

- average charges for dedicated connection assets; plus
- average charges for use of the shared network.

The categories utilised in developing the standard customer tariffs are set out in Table 125.

32.4.4. Embedded generators

The embedded generator class applies to generators connected to the distribution system. Embedded generators are separated into two categories:

- embedded generators that are connected to and only generate into the distribution system. Embedded generator tariffs for these kinds of embedded generators are based on identifying the actual dedicated connection assets utilised by the generator; or
- embedded generators that are connected to the distribution system, generate for part of the Regulatory Year and take load from the distribution system for the other part of the Regulatory Year. Embedded generator tariffs for these kinds of embedded generators are based on identifying the actual dedicated connection assets utilised by the generator. For the load side of the embedded generator, tariffs are based on identifying the actual dedicated and shared connection assets utilised by the load, depending on the user class category allocated (ICC, >2MVA or standard).

32.4.5. Meeting the requirements of the Rules

Aurora's processes for assigning tariffs to customers meet the requirements of clauses 6.18.4(a)(1) and 6.18.4(a)(2) because customers:

- are assigned on the basis of the nature of their connection, their forecast usage and size;
- with remote read interval meters are assigned a differing charge in accordance with Aurora's metering fees; and
- with the same connection and usage profiles are treated on a consistent basis.

Aurora's processes for assigning tariffs to customers meet the requirements of clause 6.18.4(a)(3) because Aurora does not treat customers with micro-generation facilities less favourably than other customers. Customers with micro-generation facilities are

Table 125

Standard customer classes

Category		Description
High voltage		All high voltage customers
Low voltage business	> 300 kVA	Low voltage business customers with demand greater than 300 kVA
Low voltage business	70-300 kVA	Low voltage business customers with demand between 70 and 300 kVA
Low voltage business	25-70 kVA	Low voltage business customers with demand between 25 and 70 kVA
Low voltage business	< 25 kVA	Low voltage business customers with demand less than 25 kVA
Uncontrolled energy		Typically those loads that supply hot water or space heating
Controlled energy		Off peak supply
Residential		All residential customers
Unmetered supplies		Unmetered supplies, except streetlights
Streetlighting		Streetlight supplies

charged the network tariff for supply to their connection point calculated in accordance with the same methodology as any other network customers.

With respect to clause 6.18.4(a)(4), Aurora does not reassign customers without careful review and good reasons and generally only following a customer request for reassignment. Reassignment would only occur in a situation where a customer alters the underlying characteristics of their connection, in terms of size or nature of usage.

With respect to clause 6.18.4(b), Aurora reviews and, if necessary, alters its tariffs each Regulatory Year and will continue to do so in the forthcoming Regulatory Control Period.

32.5. Basis for reporting to AER on recovery of TUoS charges

Clause 6.12.1(19) of Rules states that a Distribution Determination is predicated on a decision by the AER on, amongst other things, how the DNSP is to report to the AER on its recovery of TUoS charges for each Regulatory Year of the *Regulatory Control Period* and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.

Aurora currently reports to OTTER annually on the recovery of transmission charges from its network tariffs, and makes adjustments in subsequent pricing periods to account for over or under recovery of those charges. Aurora proposes to continue this process with the AER in the forthcoming *Regulatory Control Period*.

A worked example of Aurora's proposed methodology for under/over recoveries of transmission charges is appended as an attachment to this *Regulatory Proposal*.

33. Alternative Control Services

33. Alternative Control Services

33. Alternative Control Services

33.1. Overview and Rules requirements

Clauses 6.2.6(b) and (c) of the *Rules* provide that, for *Alternative Control Services*, the control mechanism must have a basis stated in the Distribution Determination and the control mechanism may (but need not) utilise elements of Part C of Chapter 6 of the *Rules* (with or without modification).

Clause 6.8.2(c)(3) of the *Rules* provides that Aurora's *Regulatory Proposal* must, for *Direct Control Services* classified as *Alternative Control Services*, provide a demonstration of the application of the control mechanism, as set out in the Framework and Approach paper and the necessary supporting information.

Clause 6.8.2(c)(4) of the *Rules* provides that Aurora's *Regulatory Proposal* must, for *Direct Control Services*, provide indicative prices for each year of the *Regulatory Control Period*.

As identified in chapter 6 of this *Regulatory Proposal*, the AER's final Framework and Approach paper classified the following categories of *Direct Control Services* as *Alternative Control Services* with the form of control for all services being a price cap:

- metering services;
- public lighting services;
- fee-based services; and
- quoted (non-standard) services.

Aurora has adopted the classification of these services as outlined in the AER's Framework and Approach.

This chapter sets out the control mechanisms for Aurora's *Alternative Control Services*, demonstrates the application of these control mechanisms in accordance with the requirements of the *Rules*, and sets out indicative prices for each service provided for each year of the forthcoming *Regulatory Control Period*.

33.2. Metering services

Metering services are those services provided with respect to the provision, installation and maintenance of standard meters and associated services provided to non-contestable customers. This includes the metering services provided using type 5 – 7 metering installations in Aurora's role as Metering Provider and Meter Data Provider (MDP).

Metering services excludes:

- MDP services for type 1 – 4 metering installations, which are proposed to be unregulated;
- meters provided by Aurora Retail to provide PAYG services, which are proposed to be unregulated; and
- metering to a standard in excess of that required for the billing of customer services, which are proposed to be quoted (non-standard) services.

The control mechanism for metering services in the current *Regulatory Control Period* is a price cap with the charges for metering services established using an annuity approach, which sets a cap on the maximum daily meter allowance for each meter class.

OTTER historically:

- applied an annuity approach on the basis that it was felt that it would be impractical to assess the age of the meter stock and an assumption that an annuity approach would give an equivalent annual charge to that expected over the long-term from a building block approach using depreciated optimised replacement cost; and
- determined to express the maximum allowable revenue for the provision of metering services (as a declared service) as an average daily allowance per meter for each major customer class. This was calculated from forecast costs and forecast numbers of meters in each class.[1]

1 Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Final Report and Proposed Maximum Prices, September 2007, page 268.

The AER, in its final Framework and Approach, proposed that metering services should be classified as *Direct Control Services* and further classified as *Alternative Control Services*, subject to a price cap form of control.

Aurora proposes to apply a price cap form of control for the forthcoming *Regulatory Control Period* to all metering services, with the charges for metering services based on the current annuity approach. This is discussed in greater detail below.

33.2.1. Levels of service

The forecast costs for metering services for the forthcoming *Regulatory Control Period* have been developed with regard to the levels of service currently provided by Aurora, including timeframes and conditions.

The levels of service currently provided by Aurora are established in accordance with the requirements of:

- the *Rules*, in particular section 7.6, which sets out the requirements for the inspection, testing and auditing of metering installations;
- the *TEC*, section 9.18, which establishes the approved maintenance plan for metering equipment and the maximum period between meter installation tests, and requires that the maximum period between tests is:
  - › 10 years for CT meters;
  - › 5 years for electronic CT connected meters; and
  - › 5 years for induction CT connected meters;
- the *TEC*, section 9.18, which requires that Aurora establish and maintain a sampling plan to ensure that each class of metering equipment is tested in accordance with AS/NZS 1284.13;
- the *TEC*, section 9.18, which sets out Aurora's obligations in relation to repairing or replacing defective metering equipment;
- AS/NZS 1284.13:2002 - Electricity Metering In-Service Compliance Testing, with respect to compliance testing; and
- historic business practice with recognition of changes in customer service delivery expectations over time. This is established using records of metering assets from completed service orders to install, read, alter and remove metering equipment, and also from periodic routine testing and inspection programs. The equipment details and attributes are recorded within Aurora's MDMS.

The forecast costs for metering services for the forthcoming *Regulatory Control Period* are based on Aurora maintaining its existing service levels, in compliance with its regulatory obligations.

33.2.2. Application and demonstration of form of control

This section outlines Aurora's proposed application of the control mechanism for metering services and the method by which compliance with the control mechanisms can be demonstrated, in accordance with clauses 6.2.6(b), (c) and 6.8.2(c)(3) of the *Rules*.

In establishing the control mechanism, Aurora has not utilised Part C of Chapter 6 of the *Rules*.

Aurora proposes to apply a price cap form of control for the forthcoming *Regulatory Control Period* to all metering services. The control mechanism will be an annuity approach that sets a cap on the maximum daily meter allowance for each meter class. This is consistent with the current regulatory approach adopted by OTTER and with the AER's stated likely approach for the forthcoming *Regulatory Control Period*[2].

The annuity approach is based on meter replacement cost, operating expenditure (which is predominately meter reading costs), capital expenditure and an allocation of overhead costs.

The annuity approach:

- undertakes an annuity calculation for each meter type for each year using the Excel-based PMT function in which:
  - › the replacement cost of each meter type is the present value parameter (this is escalated across the *Regulatory Control Period* using materials escalation rates);
  - › the asset standard life is the number of years; and
  - › a pre-tax real WACC (derived using values set out in chapter 20 of this *Regulatory Proposal*) provides the rate of return;
- estimates operating expenditure associated with the maintenance of metering assets (predominately the cost of meter reading). The associated costs are sourced from Aurora's work program, which provides associated volumes, and Aurora's unit rates model, which provides the relevant costs associated with each meter class. The relevant escalation rates across the *Regulatory Control Period* are already applied to this expenditure;
- applies operating overhead costs (Corporate and Shared Services, Network Division Management and Distribution Business Shared Resource costs) to the operating expenditure component in accordance with the approach set out in Aurora's proposed CAM. The relevant escalation rates across the *Regulatory Control Period* are already applied to this overhead expenditure; and
- undertakes an annuity calculation for shared services capital overhead costs (comprising Corporate and Shared Services and Network Division Management capital overhead costs) in accordance with the methodology set out in Aurora's proposed CAM, and apportioned to meter classes on the basis of forecast volumes.

  The annuity calculation is undertaken for assets in service at 30 June 2012 and for capital overhead costs applied to metering services in the *Regulatory Control Period* in which:
  - › for overhead assets in service at 30 June 2012:
    - the written down book value of the assets is the present value parameter;
    - the remaining weighted average asset life is the number of years; and
    - a pre-tax real WACC provides the rate of return;

2 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 84.

- for capital overhead costs applied to metering services:
  - the applied capital overhead costs is the present value parameter;
  - the asset standard life is the number of years; and
  - a pre-tax real WACC provides the rate of return;
- aggregates the annuity calculations and operating expenditure (including overheads) for each meter class, which is then divided by the number of meters in a class, to give an average annual allowance for metering for the class; and
- divides the total by the number of days in the year to give a daily allowance for each metering class.

This process, for each meter class, can be summarised as:

[(annuity for replacement costs including escalations) + (operating expenditure including operating overheads) + (annuity for overhead assets in service) + (annuity for capital overhead costs)] / (days in year)

33.2.3. Indicative prices

Table 126 provides indicative prices for metering services by meter class for each year of the forthcoming *Regulatory Control Period*, in accordance with clause 6.8.2(c)(4) of the *Rules*.

Indicative prices have been shown in 2011-12 cents per day, however, it is noted that actual prices depend on specific meter classes and tariff combinations. For this reason the above prices are considered indicative only, are not binding and are for the purposes of providing a high level overview of the expected price impact for the forthcoming *Regulatory Control Period* only.

Actual prices for the forthcoming *Regulatory Control Period* will be determined following the submission and approval of Aurora's annual Pricing Proposal to the AER in accordance with clause 6.18.2 of the *Rules*.

All indicative prices are exclusive of GST.

Table 126

Indicative prices for metering services (cents 2011-12)

Meter class	2012-13 (c/day)	2013-14 (c/day)	2014-15 (c/day)	2015-16 (c/day)	2016-17 (c/day)
Domestic LV – single phase	9.842	10.068	10.195	9.883	9.977
Domestic LV – multi phase	14.703	14.705	14.681	14.149	13.940
Domestic LV – CT meters	26.521	26.575	26.577	25.892	25.601
Domestic LV – single phase – remote read	9.570	9.638	9.641	9.207	9.084
Domestic LV – multi phase– remote read	18.209	18.374	18.420	17.891	17.708
Domestic LV – CT meters– remote read	24.749	24.889	24.927	24.298	24.071
Business LV – single phase	9.318	9.269	11.254	13.052	13.138
Business LV – multi phase	15.738	16.760	17.679	17.916	18.162
Business LV – CT meters	22.837	23.906	24.818	24.942	25.316
Business LV – single phase– remote read	12.293	12.282	12.250	11.753	11.611
Business LV – multi phase– remote read	18.209	18.374	18.420	17.891	17.708
Business LV – CT meters– remote read	24.749	24.889	24.927	24.298	24.071
Other meters	15.172	15.303	15.338	14.859	14.664

33.3. Public lighting services

Public lighting services are those services provided by Aurora for:

- the provision, maintenance and replacement of public lighting assets owned by Aurora;
- the maintenance of public lighting assets owned by customers (contract lighting); and
- the provision, maintenance and replacement of Aurora owned public lighting poles.

Although not expressly addressed in the final Framework and Approach, Aurora interprets the 'repair, replacement and maintenance' of luminaires and public lighting poles, as the 'routine' provision of the repair, replacement or maintenance service.

Public lighting services exclude:

- the alteration and relocation of public lighting assets, which will be provided on a quoted service basis and is therefore categorised as a quoted (non-standard) service;
- the installation of contract lights, which will be provided on a quoted service basis and is therefore categorised as a quoted (non-standard) service; and
- the provision of new public lighting technologies, which will be classified as a *Negotiated Distribution Service*.

Public lighting services are unregulated in the current *Regulatory Control Period* and have previously never been regulated.

Aurora has historically derived its charges for public lighting services through an annuity approach, through its public lighting annuity model.

The AER, in its final Framework and Approach, proposed that public lighting services should be classified as *Direct Control Services* and further classified as *Alternative Control Services*, subject to a price cap form of control.

Aurora proposes to apply a price cap form of control for the forthcoming *Regulatory Control Period* to all public lighting services, with the charges for public lighting services provided under a schedule of fees, based on the current annuity approach. This is discussed in greater detail below.

33.3.1. Levels of service

The forecast costs for public lighting services for the forthcoming *Regulatory Control Period* have been developed with regard to the levels of service currently provided by Aurora, including timeframes and conditions.

The levels of service currently provided by Aurora are established in accordance with the requirements of:

- Aurora's Distribution Customer Charter which states the services and the level and standard of such services that a customer is entitled to receive from Aurora. Individual service failures against the service timeframes result in a GSL payment to the customer. The Distribution Customer Charter is approved by OTTER pursuant to clause 8.3.1 of the *TEC*;
- section 8.2.3 of the *TEC* which requires Aurora to repair or replace an item of public lighting within seven business days of being notified by any person that such repair or replacement is necessary, unless the public lighting provider has contractual or other arrangements with another party;
- standards including AS/NZS 1158 – Lighting for Roads and Public Spaces. Aurora's public lighting assets are classified by AS/NZS 1158 into the following categories:
    - › Category 'V' - generally referred to as major public lighting, which is applicable to roads where the visual requirements of motorists are dominant; and
    - › Category 'P' - generally referred to as minor public lighting, which is applicable to roads where the visual requirements of pedestrians are dominant. This category also applies to outdoor public areas, other than roads, where the visual requirements of pedestrians are dominant, such as outdoor shopping precincts.

This classification will influence luminaire type and size and therefore associated costs;

- AS/NZS 1158.1.2, which recommends that Aurora undertake a maximum maintenance cycle of four years for bulk replacement programs associated with major public lighting and minor public lighting; and
- AS/NZS 1158.1.2 Section 14.5.2, which requires that Aurora undertake a night patrol program for major public lighting to ensure that the minimum service availability of lamps at a compliant public lighting installation is 95 percent, and to ensure that all major lighting schemes maintain designed illumination levels.

The forecast costs for public lighting services for the forthcoming *Regulatory Control Period* are based on Aurora maintaining its existing service levels, in compliance with its regulatory obligations.

33.3.2. Application and demonstration of form of control

This section outlines Aurora's proposed application of the control mechanism for public lighting services and the method by which compliance with the control mechanisms can be demonstrated, in accordance with clauses 6.2.6(b), (c) and 6.8.2(c)(3) of the *Rules*.

In establishing the control mechanism, Aurora has not utilised the building block approach of Part C of Chapter 6 of the *Rules*.

Aurora proposes to apply a price cap form of control for the forthcoming *Regulatory Control Period* to all public lighting services. The control mechanism will be an annuity approach that sets a cap on the maximum daily fee for each lighting class. This is consistent with the current approach adopted by Aurora and with the AER's stated likely approach for the forthcoming *Regulatory Control Period*[3]. Aurora proposes to apply the control mechanism through an annuity approach that derives a daily fee for:

- each luminaire type, for the provision, maintenance and replacement of public lighting assets owned by Aurora;

3 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 74.

- each luminaire type, for the maintenance of public lighting assets owned by customers (contract lighting); and
- the provision, maintenance and replacement of certain Aurora owned poles.

These charges reflect the fact that it is possible to forecast costs associated with public lighting services on the basis of past expenditure and forecast inspection cycles. As such, it is possible to develop a fee associated with the provision of each service type.

Although Aurora's poles and lighting structures revenues are typically classified as *Standard Control Services*, there are certain poles which Aurora, for historical reasons, owns and levies a surcharge (these were assets assigned to Aurora (Hydro) during the period 1974-81). Aurora uses the annuity approach to determine the charges associated with the provision, maintenance and replacement of these Aurora owned poles. A single charge is calculated for this service, regardless of the pole type.

Aurora owned public lighting

Aurora's public lighting annuity model carries out an annuity calculation for the replacement cost of each lamp, bracket and luminaire type for each year of the forthcoming *Regulatory Control Period*.

The annuity approach is based on lighting replacement cost, operating expenditure (which is predominately globe replacement costs), capital expenditure and an allocation of overhead costs.

The annuity approach:

- undertakes an annuity calculation for each public lighting type for each year using the Excel-based PMT function in which:
  - › the replacement cost of each public lighting type is the present value parameter (this is escalated across the *Regulatory Control Period* using materials escalation rates);
  - › the asset standard life is the number of years; and
  - › a pre-tax real WACC (derived using values set out in chapter 20 of this *Regulatory Proposal*) provides the rate of return;
- estimates operating expenditure associated with the maintenance of public lighting assets (predominately globe replacement costs). The associated costs are sourced from Aurora's work program, which provides associated volumes, and Aurora's unit rates model, which provides the relevant costs associated with each public lighting class. The relevant escalation rates across the *Regulatory Control Period* are already applied to this expenditure;
- applies operating overhead costs (Corporate and Shared Services, Network Division Management and Distribution Business Shared Resource costs) to the operating expenditure component in accordance with the approach set out in Aurora's proposed CAM. The relevant escalation rates across the *Regulatory Control Period* are already applied to this overhead expenditure; and
- undertakes an annuity calculation for shared services capital overhead costs (comprising Corporate and Shared Services and Network Division Management capital overhead costs) in accordance with the methodology set out in Aurora's proposed CAM, and apportioned to public lighting classes on the basis of forecast volumes.

The annuity calculation is undertaken for assets in service at 30 June 2012 and for capital overhead costs applied to public lighting services in the *Regulatory Control Period* in which:

- for overhead assets in service at 30 June 2012:
  - › the written down book value of the assets is the present value parameter;
  - › the remaining weighted average asset life is the number of years; and
  - › a pre-tax real WACC provides the rate of return;
- for capital overhead costs applied to public lighting services:
  - › the applied capital overhead costs is the present value parameter;
  - › the asset standard life is the number of years; and
  - › a pre-tax real WACC provides the rate of return;
- aggregates the annuity calculations and operating expenditure (including overheads) for each public lighting class to give an average annual allowance for lighting for the class; and
- divides the total by the number of days in the year to give a daily allowance for each public lighting class.

This process, for each public lighting class, can be summarised as:

> *[(annuity for replacement costs including escalations) + (operating expenditure including operating overheads) + (annuity for overhead assets in service) + (annuity for capital overhead costs)] / (days in year)*

To determine the final charge for customers a NUOS charge is also applied. However, these charges are not *Alternative Control Services*, but are rather derived as part of the tariff setting process for *Standard Control Services* and are not included in the proposed prices set out in this chapter.

Contract lighting

Aurora's public lighting annuity model carries out an annuity calculation for the maintenance cost of each contract lamp for each year of the forthcoming *Regulatory Control Period*.

The annuity approach is based on operating expenditure (which is predominately globe replacement costs) and an allocation of overhead costs.

The annuity approach:

- estimates operating expenditure associated with the maintenance of contract lighting assets (predominately globe replacement costs). The associated costs are sourced from Aurora's work program, which provides associated volumes, and Aurora's unit rates model, which provides the relevant costs associated with each lighting class. The relevant escalation rates across the *Regulatory Control Period* are already applied to this expenditure;
- applies operating overhead costs (Corporate and Shared Services, Network Division Management and Distribution Business Shared Resource costs) to the operating expenditure component in accordance with the approach set out in Aurora's proposed CAM. The relevant escalation rates across the *Regulatory Control Period* are already applied to this overhead expenditure; and

- undertakes an annuity calculation for shared services capital overhead costs (comprising Corporate and Shared Services and Network Division Management capital overhead costs) in accordance with the methodology set out in Aurora's proposed CAM, and apportioned to contract lighting classes on the basis of forecast volumes.

The annuity calculation is undertaken for assets in service at 30 June 2012 and for capital overhead costs applied to contract lighting services in the *Regulatory Control Period* in which:

- for overhead assets in service at 30 June 2012:
  - › the written down book value of the assets is the present value parameter;
  - › the remaining weighted average asset life is the number of years; and
  - › a pre-tax real WACC provides the rate of return;
- for capital overhead costs applied to contract lighting services:
  - › the applied capital overhead costs is the present value parameter;
  - › the asset standard life is the number of years; and
  - › a pre-tax real WACC provides the rate of return;
- aggregates the annuity calculations and operating expenditure (including overheads) for each contract lighting class to give an average annual allowance for contract lighting for the class; and
- divides the total by the number of days in the year to give a daily allowance for each contract lighting class.

This process, for each contract lighting class can be summarised as:

[(operating expenditure including operating overheads) + (annuity for overhead assets in service) + (annuity for capital overhead costs)] / (days in year)

To determine the final charge for customers a NUOS charge is also applied. However, these charges are not *Alternative Control Services*, but are rather derived as part of the tariff setting process for *Standard Control Services* and are not included in the proposed prices set out in this chapter.

Basis of calculations

The following inputs form the basis of the above calculations:

- replacement volumes – replacement of public lighting is undertaken on a routine basis throughout each year. Aurora has developed projected public lighting replacement volumes for each bracket, lamp and luminaires type required for each lighting type. Projections have regard for any likely volume growth over the forthcoming *Regulatory Control Period*;
- material replacement costs – for each public lighting service type the relevant volumes are multiplied by the bracket, lamp and luminaires costs as the basis of the annuity calculation;
- standard lives – Aurora maintains a register of asset data that is used to determine the standard life of each asset. This is input into the annuity calculation to derive the number of years over which the replacement cost is recovered;
- escalation rates – input data provided for calculation purposes within the public lighting annuity model has been provided using forecast 2009-10 values. Accordingly, costs are increased across the *Regulatory Control Period* by:
  - › forecast CPI in order to calculate nominal costs; and
  - › escalation rates (using SKM escalation rates) which are applied by asset type for capital expenditure, and by discrete cost type (materials, contractors, labour and other) for operating expenditure;
- capital expenditure forecasts – Aurora has developed the material replacement costs and installation costs for all bracket, lamp and luminaire types, using forecast 2009-10 values, incorporating the materials escalation rate;
- operating expenditure forecasts – Aurora's work program is used to forecast operating expenditure volumes associated with public lighting assets;
- overhead costs allocation – the operating expenditure components of Corporate and Shared Services; Network Management; and Distribution Business Shared Resource costs are apportioned on a percentage spend of direct costs, in accordance with Aurora's CAM;
- capital overhead cost component – the capital overhead cost component is apportioned in accordance with the methodology in Aurora's proposed CAM; and
- return on capital – the return on capital is a pre-tax real WACC derived using values set out in chapter 20 of this *Regulatory Proposal*.

33.3.3. Indicative prices

Table 127 provides indicative prices for public lighting services (where the public lighting is owned by Aurora) for each year of the forthcoming *Regulatory Control Period*, in accordance with clause 6.8.2(c)(4) of the *Rules*.

Table 127

Indicative prices for public lighting services (cents 2011-12)

Lighting type	2012-13 (c/day)	2013-14 (c/day)	2014-15 (c/day)	2015-16 (c/day)	2016-17 (c/day)
42W mercury vapour	38.027	37.894	37.439	39.385	37.998
50W mercury vapour	35.623	35.465	34.999	36.957	35.577
80W mercury vapour – Aeroscreen	35.623	35.465	34.999	36.957	35.577
80W mercury vapour – Artcraft decorative	56.626	56.688	56.309	58.175	56.729
125W mercury vapour	41.173	40.909	40.379	42.222	40.725
250W mercury vapour	41.679	41.421	40.893	42.734	41.235
400W mercury vapour	46.589	46.382	45.875	47.694	46.180
70W sodium vapour	38.093	37.961	37.505	39.452	38.065
100W sodium vapour	38.136	37.949	37.467	39.377	37.953
150W sodium vapour	42.483	42.233	41.709	43.547	42.045
250W sodium vapour	42.621	42.373	41.849	43.686	42.184
400W sodium vapour	42.846	42.600	42.077	43.913	42.410
150W metal halide	42.483	42.233	41.709	43.547	42.045
250W metal halide	42.621	42.373	41.849	43.686	42.184
2 x 20W fluorescent	40.088	39.976	39.529	41.467	40.074
2 x 40W fluorescent	39.543	39.371	38.894	40.798	39.370
42W compact fluorescent	38.027	37.894	37.439	39.385	37.998
60W incandescent	34.921	34.755	34.287	36.247	34.870

Table 128 provides indicative prices for contract lighting services for each year of the forthcoming *Regulatory Control Period*, in accordance with clause 6.8.2(c)(4) of the *Rules*.

Table 128

Indicative prices for contract lighting services (cents 2011-12)

Lighting type	2012-13 (c/day)	2013-14 (c/day)	2014-15 (c/day)	2015-16 (c/day)	2016-17 (c/day)
50W mercury vapour	22.975	22.835	22.398	24.476	23.209
80W mercury vapour	22.962	22.821	22.384	24.462	23.196
125W mercury vapour	23.896	23.711	23.250	25.288	23.982
250W mercury vapour	23.978	23.794	23.334	25.371	24.064
400W mercury vapour	24.040	23.856	23.397	25.434	24.127
70W sodium vapour	23.185	23.047	22.611	24.688	23.421
150W sodium vapour	24.702	24.525	24.068	26.102	24.793
250W sodium vapour	24.664	24.487	24.030	26.064	24.755
400W sodium vapour	24.748	24.572	24.115	26.149	24.840
150W metal halide	24.702	24.525	24.068	26.102	24.793
250W metal halide	24.664	24.487	24.030	26.064	24.755
400W metal halide	24.664	24.487	24.030	26.064	24.755
1 x 20W fluorescent	23.036	22.896	22.459	24.537	23.270
2 x 20W fluorescent	23.170	23.031	22.595	24.672	23.405
1 x 40W fluorescent	23.045	22.905	22.468	24.546	23.279
2 x 40W fluorescent	24.106	23.923	23.464	25.500	24.193
3 x 40W fluorescent	24.249	24.067	23.608	25.644	24.337
4 x 40W fluorescent	25.189	25.017	24.562	26.594	25.284
60W incandescent	22.959	22.819	22.381	24.460	23.193
100W incandescent	23.878	23.693	23.232	25.270	23.964
Pole surcharge	24.175	24.175	24.175	24.109	24.175

Indicative prices have been shown in 2011-12 cents per day and are considered indicative only, are not binding and are for the purposes of providing a high level overview of the expected price impact for the forthcoming *Regulatory Control Period* only.

Actual prices for the forthcoming *Regulatory Control Period* will be determined following the submission and approval of Aurora's annual Pricing Proposal to the AER in accordance with clause 6.18.2 of the *Rules*.

All indicative prices are exclusive of GST.

33.4. Fee-based services

Fee-based services are those services provided by Aurora where the service is, in general, provided for the benefit of a single customer rather than uniformly supplied to all customers. These services are provided at the request of a third party and are typically initiated by way of a service request received from a retailer.

Examples of services Aurora provides on a fee-basis include, but are not limited to:

- energisation;
- de-energisation;
- re-energisation;
- meter alteration;
- meter testing;
- new connection – permanent supply;
- supply abolishment – removal of meters and service connection;
- renewable energy connection; and
- other miscellaneous services.

These services are largely homogenous in nature and therefore a fixed fee can be set in advance with reasonable certainty. That is, the costs inputs in providing these services do not involve material variations.

In the current *Regulatory Control Period*, these services form Declared Special Services and have been classified by OTTER as:

- standard special services (for energisation, de-energisation, re-energisation, meter alteration and meter testing) – these services are regulated under a weighted average price cap with prices charged on the basis of fixed fees. Individual service prices are determined annually through the price setting process with OTTER with increases, where approved, not exceeding the Weighted Average Wage Index for the Electricity, Gas and Water Supply Industry in the preceding calendar year; and
- other special services (all other proposed fee-based services) – these services are not regulated under a price cap although the services and their prices are approved by OTTER on an annual basis through Aurora's price setting process.

The AER, in its final Framework and Approach, proposed that all fee-based services should be classified as *Direct Control Services* and further classified as *Alternative Control Services*, subject to a price cap form of control.

That is, that a price cap should continue to be applied to all standard special services and that the other special services should be incorporated into the price cap form of control.

Aurora proposes to apply a price cap form of control for the forthcoming *Regulatory Control Period* to all fee-based services (both standard and other special services), with caps applied to individual services under a schedule of fees. This is discussed in greater detail below.

33.4.1. Levels of service

The forecast costs for fee-based services for the forthcoming *Regulatory Control Period* have been developed with regard to the levels of service currently provided by Aurora, including timeframes and conditions.

The levels of service currently provided by Aurora are established in accordance with the requirements of:

- Aurora's Distribution Customer Charter which states the services and the level and standard of such services that a customer is entitled to receive from Aurora. Individual service failures against the service timeframes result in a GSL payment to the customer. The Distribution Customer Charter is approved by OTTER pursuant to clause 8.3.1 of the *TEC*;
- Aurora's prices for the provision of Distribution Special Services which provides for services to be delivered in accordance with established service level agreements and regulatory requirements. The prices for the provision of Distribution Special Services are approved by OTTER as part of the annual pricing approval process;
- the *TEC*, in particular section 9.17, which governs the testing of metering equipment of non-contestable customers and the timeframes within which field testing must be conducted, and states that Aurora must, within 15 business days of a request from a customer, test metering equipment to ascertain whether the metering equipment is defective;
- Aurora's service level agreement with retailers which governs timeframes for delivery of certain categories of fee-based services; and
- internally derived performance targets, in circumstances where service levels have not been externally imposed or approved. These are based upon historic business practice, with recognition of changes in customer service delivery expectations over time.

The forecast costs for fee-based services for the forthcoming *Regulatory Control Period* are based on Aurora maintaining its existing service levels, in compliance with its regulatory obligations. Changes to the standard conditions or levels of service provision to reflect specific customer requirements will constitute a quoted (non-standard) service.

Table 129 contains:

- a list of fee-based services categories;
- the service level obligations associated with each service; and
- related service targets.

Table 129

Service levels for fee-based services

Service category	Source	Service level
Energisation, de-energisation and re-energisation	Electricity Supply Industry (Tariff Customers) Regulations 2008, section 31	10 business days for a new connection if no extension of the network is required. 40 business days for a new connection if an extension of the network is required. 1 business day if a reconnection does not involve any changes to the network. 10 business days if a reconnection involves changes to the network.
Meter alteration	Service Level Agreement with retailer	All services to be delivered no later than 10 business days of receiving retailer service request (unless otherwise agreed).
Meter test	*TEC*, section 9.17.1	Test of metering equipment to be delivered within 15 business days of a request from a Tariff Customer.
New connection – permanent supply	Electricity Supply Industry (Tariff Customers) Regulations 2008, section 31	10 business days for a new connection if no extension of the distribution network is required.
Supply abolishment	Service level agreement with retailer	All services to be delivered no later than 5 business days of receiving retailer service request (unless otherwise agreed).
Renewable energy connection	Electricity Supply Industry (Tariff Customers) Regulations 2008, section 31	10 business days for a new connection if no extension of the distribution network is required.
New connection – temporary and temporary in permanent position	Electricity Supply Industry (Tariff Customers) Regulations 2008, section 31	10 business days for a new connection if no extension of the distribution network is required.
New connection – temporary show and carnival connection	Electricity Supply Industry (Tariff Customers) Regulations 2008, section 31	10 business days for a new connection if no extension of the distribution network is required.
Truck tee-up	Internal target between Aurora and contractor	2 business days after receiving advice from the contractor.
Miscellaneous services	Electricity Supply Industry (Tariff Customers) Regulations 2008, section 31	10 business days for a new connection if no extension of the distribution network is required.

33.4.2. Application and demonstration of form of control

This section outlines Aurora's proposed application of the control mechanism for fee-based services and the method by which compliance with the control mechanisms can be demonstrated, in accordance with clauses 6.2.6(b), (c) and 6.8.2(c)(3) of the *Rules*.

In establishing the control mechanism, Aurora has not utilised Part C of Chapter 6 of the *Rules*.

Aurora proposes to apply a price cap form of control for the forthcoming *Regulatory Control Period* to all fee-based services. This is consistent with the current regulatory approach adopted by OTTER and with the AER's stated likely approach for the forthcoming *Regulatory Control Period*[4].

Aurora proposes to apply the control mechanism for each of the fee-based services to be offered, through the build up, through Aurora's fee-based services model, of the following cost components:

- labour;
- materials;
- contractors; and
- other costs.

Aurora's fee-based services model:

- establishes, for each fee-based service, estimated task time and skill set requirements based on Aurora's historical data and projected volumes for each year of the forthcoming *Regulatory Control Period* of Aurora's anticipated work program;
- builds up a schedule of fixed prices for each year of the forthcoming *Regulatory Control Period* using the cost for each fee-based service using the costings for relevant activities derived in the fee-based services model;
- applies operating overhead costs (Corporate and Shared Services, Network Division Management and Distribution Business Shared Resource costs) to the schedule of fixed prices for year one in accordance with the approach set out in Aurora's proposed CAM. The relevant escalation rates across the forthcoming *Regulatory Control Period* are already applied to this overhead expenditure; and
- undertakes an annuity calculation for shared services capital overhead costs (comprising Corporate and Shared Services and Network Division Management capital overhead costs) in accordance with the methodology set out in Aurora's proposed CAM, and apportioned to fee-based services on the basis of forecast volumes.

  The annuity calculation is undertaken for assets in service at 30 June 2012 and for capital overhead costs applied to public fee-based services in the *Regulatory Control Period* in which:

  - › for overhead assets in service at 30 June 2012:
    - the written down book value of the assets is the present value parameter;
    - the remaining weighted average asset life is the number of years; and
    - a pre-tax real WACC provides the rate of return;
  - › for capital overhead costs applied to fee-based services:
    - the applied capital overhead costs is the present value parameter;
    - the asset standard life is the number of years;
    - a pre-tax real WACC provides the rate of return; and
- aggregates the annuity calculations and schedule of year one fees (including overheads) for each fee-based service to give a final price for each service.

This process, for each fee-based service can be summarised as:

(fee schedule including operating overheads) + (annuity for overhead assets in service) + (annuity for capital overhead costs)

The following provides further detail on fee-based services inputs:

- fee-based services model – the fee-based services model uses labour, materials, contractors and other costs to determine the overall costs and to develop the schedule of fixed prices for fee-based services for each year of the forthcoming *Regulatory Control Period*;
- labour rates – the costs of providing fee-based services are principally labour related costs. Labour rates are based on a weighted average hourly rate (by skill set), for all of the staff who perform these tasks. The rates have been adjusted for each year of the forthcoming *Regulatory Control Period* to reflect expected increases in efficiency. It is noted that the task time for after hours fault work is set to 4 hours, as field staff are paid this as a minimum under Aurora's enterprise agreement;
- CPI and escalation rates – input data provided for calculation purposes within the fee-based services model has been provided using forecast 2009-10 values. Accordingly, costs are increased across the forthcoming *Regulatory Control Period* by:
  - › forecast CPI in order to calculate nominal costs; and
  - › escalation rates (derived by SKM) which are applied by asset type for capital expenditure, and by discrete cost type (materials, contractors, labour and other) for operating expenditure.

It should be noted that Aurora does not include a profit margin in any fee-based services that it provides. The prices are levied on a cost-recovery basis.

4 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 74.

33.4.3. Indicative prices

Table 130 provides indicative prices for fee-based services for each year of the forthcoming *Regulatory Control Period*, in accordance with clause 6.8.2(c)(4) of the *Rules*.

Table 130

Indicative prices for fee-based services (dollars 2011-12)

Service	2012-13 ($)	2013-14 ($)	2014-15 ($)	2015-16 ($)	2016-17 ($)
De-energisation, re-energisation and special reads					
Site visit – no appointment	61.26	61.72	61.13	55.67	54.00
Site visit – non scheduled visit	122.52	123.44	122.26	111.35	108.00
Site visit – same day premium service	321.45	323.91	320.87	292.63	283.92
Site visit – after hours	816.79	822.96	815.09	742.30	720.00
Site visit – credit action or site issues	209.14	210.75	208.79	190.56	184.92
Site visit – rectification of illegal connection	260.19	262.19	259.73	236.96	229.92
Site visit – interval metering	61.26	61.72	61.13	55.67	54.00
Site visit – late cancellation	61.26	61.72	61.13	55.67	54.00
Transfer of retailer	-	-	-	-	-
Meter alteration					
Tariff alteration – single phase	170.36	171.91	169.21	151.18	146.03
Tariff alteration – three phase	230.51	232.60	228.91	204.34	197.34
Adjust time clock	61.26	61.72	61.13	55.67	54.00
Install pulse outputs	175.11	176.46	174.83	159.63	154.92
Remove meter	293.40	298.15	295.00	265.60	255.89
Meter alteration – after hours visit	816.79	822.96	815.09	742.30	720.00
Meter alteration – late cancellation	103.84	105.53	104.39	93.82	90.35
Meter alteration – wasted visit	224.17	227.80	225.40	203.05	195.66
PAYG meter alteration					
PAYG install	115.85	115.85	115.85	115.85	115.85
PAYG removal	277.21	279.33	276.72	252.42	244.92
PAYG reconfiguration	277.21	279.33	276.72	252.42	244.92
PAYG fault	226.16	227.90	225.77	206.03	199.92
PAYG fault – after hours	816.79	822.96	815.09	742.30	720.00
PAYG POS fault	175.11	176.46	174.83	159.63	154.92
PAYG POS fault – after hours	816.79	822.96	815.09	742.30	720.00
PAYG – late cancellation	103.84	105.53	104.39	93.82	90.35
PAYG – wasted visit	224.17	227.80	225.40	203.05	195.66
Meter test					
Meter test – single phase	311.24	313.62	310.68	283.35	274.92
Meter test – multi phase	617.54	622.23	616.34	561.72	544.92
Meter test – CT	685.60	690.81	684.26	623.57	604.92
Meter test – after hours	816.79	822.96	815.09	742.30	720.00
Meter test –late cancellation	61.26	61.72	61.13	55.67	54.00
Meter test –wasted visit	224.17	227.80	225.40	203.05	195.66
Supply establishment					
New connection – install service & meters	215.47	217.42	213.99	191.05	184.51
New connection – unmetered supply	275.62	278.11	273.69	244.21	235.83
New connection – after hours	721.81	728.26	716.46	637.92	615.74
Install additional service span – single phase	410.75	418.18	413.15	374.25	361.62
Install additional service span – single phase – additional spans	306.26	311.70	308.58	282.41	273.69
Install additional service span – multi phase	582.82	593.26	586.80	534.67	517.49

Table 130

Indicative prices for fee-based services (dollars 2011-12) (continued)

Service	2012-13 ($)	2013-14 ($)	2014-15 ($)	2015-16 ($)	2016-17 ($)
Install additional service span – multi phase – additional spans	478.32	486.77	482.23	442.84	429.56
New Connection – late cancellation	103.84	105.53	104.39	93.82	90.35
New connection – wasted visit	224.17	227.80	225.40	203.05	195.66
Supply abolishment					
Remove service & meters	293.40	298.15	295.00	265.60	255.89
Supply abolishment – after hours	816.79	822.96	815.09	742.30	720.00
Supply abolishment – late cancellation	61.26	61.72	61.13	55.67	54.00
Supply abolishment – wasted visit	224.17	227.80	225.40	203.05	195.66
Renewable energy connection					
Renewable energy connection	170.36	171.91	169.21	151.18	146.03
Renewable energy connection – after hours	1,472.36	1,499.99	1,476.24	1,309.79	1,258.15
Renewable energy connection – late cancellation	103.84	105.53	104.39	93.82	90.35
Renewable energy connection – wasted visit	224.17	227.80	225.40	203.05	195.66
Temporary builders connection					
Temporary supply underground – single phase – temporary position	226.53	228.82	226.15	206.20	200.18
Temporary supply underground – three phase – temporary position	281.73	284.85	282.55	262.20	255.65
Temporary supply underground – single phase – permanent position	226.53	228.82	226.15	206.20	200.18
Temporary supply underground – three phase – permanent position	281.73	284.85	282.55	262.20	255.65
Temporary supply overhead – single phase – temporary position	499.48	508.67	501.65	450.11	433.75
Temporary supply overhead – three phase – temporary position	682.37	694.73	686.35	621.52	600.50
Temporary supply overhead – single phase – permanent position	499.48	508.67	501.65	450.11	433.75
Temporary supply overhead – three phase – permanent position	682.37	694.73	686.35	621.52	600.50
Temporary supply – after hours	1,472.36	1,499.99	1,476.24	1,309.79	1,258.15
Temporary supply – late cancellation	103.84	105.53	104.39	93.82	90.35
Temporary supply – wasted visit	224.17	227.80	225.40	203.05	195.66
Temporary show & carnival connection					
Temporary supply – underground	345.27	347.91	344.64	314.28	304.92
Temporary supply – overhead mains	429.10	434.07	431.79	400.64	389.77
Temporary supply – overhead service	896.43	911.94	904.11	821.05	792.47
Temporary supply – after hours	816.79	822.96	815.09	742.30	720.00
Temporary supply – late cancellation	61.26	61.72	61.13	55.67	54.00
Temporary supply – wasted visit	224.17	227.80	225.40	203.05	195.66
Truck tee-up					
Tee-up	795.17	810.08	797.29	707.65	679.81
Tee-up – after hours	1,354.66	1,380.11	1,358.17	1,204.56	1,156.95
Tee-up – no truck – after hours	1,194.60	1,217.65	1,194.65	1,042.16	996.12
Tee-up – late cancellation	103.84	105.53	104.39	93.82	90.35
Tee-up – wasted visit	224.17	227.80	225.40	203.05	195.66
Miscellaneous services					
Open turret	221.26	223.74	222.08	206.75	201.73
Addition/alteration to connection point	386.67	390.64	386.27	352.94	342.84
Connection of new mains to existing installation	215.47	217.42	213.99	191.05	184.51
Data download	429.10	434.07	431.79	400.64	389.77
Alteration to unmetered supply	230.51	232.60	228.91	204.34	197.34
Miscellaneous service	141.08	142.17	140.87	128.70	124.92
Miscellaneous service – after hours	816.79	822.96	815.09	742.30	720.00
Miscellaneous service – late cancellation	61.26	61.72	61.13	55.67	54.00
Miscellaneous service – wasted visit	224.17	227.80	225.40	203.05	195.66

Indicative prices have been shown in 2011-12 dollars per service and are considered indicative only, are not binding and are for the purposes of providing a high level overview of the expected price impact for the forthcoming *Regulatory Control Period* only.

Actual prices for the forthcoming *Regulatory Control Period* will be determined following the submission and approval of Aurora's annual Pricing Proposal to the AER in accordance with clause 6.18.2 of the *Rules*.

All indicative prices are exclusive of GST.

33.5. Quoted (non-standard) services

Quoted (non-standard) services are those services provided by Aurora where the nature and scope of the service is specific to individual customers' needs, and varies from customer to customer. As a consequence, the cost of providing the services cannot be estimated without first knowing the customer's specific requirements. It is not possible, therefore, to set a generic total fixed fee in advance for these services.

Requests for quoted (non-standard) services may be received from a customer or retailer on behalf of a customer.

Aurora provides a range of non-standard services on a quoted basis including, but not limited to:

- removal or relocation of Aurora's assets at a customer's (for example, the Tasmanian Government) request;
- services that are provided at a higher standard than the standard service, due to a customer's request for Aurora to do so;
- provision of public lighting schemes;
- provision of overhead and underground subdivisions for developers;
- relocation of assets at the request of a third party; and
- services that are provided through a non-standard process at a customer's request (for example, where more frequent meter reading is required).

The *AER*, in its final Framework and Approach, proposed that quoted (non-standard) services should be classified as *Direct Control Services* and further classified as *Alternative Control Services*, subject to a price cap form of control.

Aurora proposes to apply a price cap form of control for the forthcoming *Regulatory Control Period* to all quoted (non-standard) services, with caps applied to the individual unit costs of inputs. This is discussed in greater detail below.

33.5.1. Levels of service

The forecast costs for quoted (non-standard) services for the forthcoming *Regulatory Control Period* have been developed with regard to the levels of service currently provided by Aurora, including timeframes and conditions.

The levels of service currently provided by Aurora are established in accordance with the requirements of historic business practice, with recognition of changes in customer service delivery.

The forecast costs for quoted (non-standard) services for the forthcoming *Regulatory Control Period* are based on Aurora maintaining its existing service levels.

33.5.2. Application and demonstration of form of control

This section outlines Aurora's proposed application of the control mechanism for quoted (non-standard) services and the method by which compliance with the control mechanisms can be demonstrated, in accordance with clauses 6.2.6(b), (c) and 6.8.2(c)(3) of the *Rules*.

In establishing the control mechanism, Aurora has not utilised Part C of Chapter 6 of the *Rules*.

Aurora proposes to apply a price cap form of control for the forthcoming *Regulatory Control Period* to all quoted (non-standard) services, through a formula based approach (i.e. non building-block) with caps applied to the individual unit costs of inputs. This formula based approach will ensure that prices reflect the actual costs of service provision to meet the customer's specific needs.

The following cost build-up, sourced from Aurora's Design and Estimation Module of WASP (and including all applicable overheads), is proposed to be applied to establish the price caps on the individual components of quoted (non-standard) services:

Price = Labour + Materials + Contractors + Other Costs + Overheads

Where:

- labour and related expenditure includes costs associated with Aurora's internal resources and labour contractors. Costs are allocated to a job number in the WASP database by way of standard calculated rates. Labour rates are calculated on a skill level basis and are inclusive of labour on-costs. Labour rates for internal employees are calculated to include normal salaries and wages, associated payroll on-costs and employee/industry allowances. Payroll on-costs include public holidays, leave, superannuation, and payroll tax. Labour rates for productive work also recover the non-productive time of employees including attendance at general and safety meetings and down-time to perform administrative duties. External labour does not attract these labour costs as the charge-out rates paid by external firms include these costs in the rates;
- materials are directly allocated to work orders at cost. They include stock items distributed through Aurora's centralised warehouse or stores and specific purchases of irregular or low turnover items such as specialised transformers, or plant and equipment. An on-cost is added to stock material to cover the cost of purchasing, warehousing and delivery of materials held in Aurora's warehouses;
- contractors and external labour may be sourced to supplement the existing workforce for specific projects, additional workloads or to cover employee absences. Contractor costs are incorporated into job costs and therefore attract a portion of Network Services management and corporate shared services overheads as per internal labour costs;

- other costs include any other associated costs that are not captured within the above categories; and
- overheads will be applied to the final components of the service provision in accordance with the methodology set out in Aurora's proposed CAM.

These individual unit costs are considered appropriate as they are derived using the dedicated Design and Estimation Module within WASP, which adopts a well-established methodology for cost estimation. Aurora does not include a profit margin in any quoted (non-standard) services that it provides. The prices are levied on a cost-recovery basis.

33.5.3. Indicative prices

Prices for quoted (non-standard) services will be calculated on an individual basis consistent with the methodology outlined above.

Aurora is unable to provide indicative prices for quoted (non-standard) services for each year of the forthcoming *Regulatory Control Period*, in accordance with clause 6.8.2(c)(4) of the *Rules*, as by their nature these services are dependent on a customer's specific requirements and cost inputs may vary significantly. This also precludes the provision of historical standardised prices.

Aurora has provided its detailed methodology and examples of quoted (non-standard) services as attachments to this *Regulatory Proposal*.

34. Negotiating Framework

34. Negotiating Framework

The *Rules* require that Aurora prepare a Negotiating Framework to govern its approach to negotiating and reaching agreement with customers regarding the delivery of *Negotiated Distribution Services*. In compliance with this requirement Aurora has developed a Negotiating Framework.

This chapter provides an overview of the approach prescribed by the Negotiating Framework; as well as a brief description of the anticipated *Negotiated Distribution Service* offered by Aurora during the forthcoming *Regulatory Control Period,* being new public lighting technologies.

34.1. Rules Requirements

The *Rules* require the following in relation to *Negotiated Distribution Services*:

- clause 6.8.2(c)(5) requires that a *Regulatory Proposal* must include, for services classified under the proposal as a *Negotiated Distribution Services*, the proposed negotiating framework;
- clause 6.7.2 requires Aurora to comply with its Negotiating Framework and to set out the preparation, replacement, application or operation of the negotiating framework;
- clause 6.7.5(a) requires Aurora to prepare a Negotiating Framework setting out the procedure to be followed during its negotiations with any person who wishes to receive a *Negotiated Distribution Service* from Aurora, as to the terms and conditions of access for the provision of the service;
- clause 6.7.5(b) requires that the Negotiating Framework for Aurora comply with, and be consistent with, the applicable requirements of the relevant Distribution Determination; and the minimum requirements for a Negotiating Framework as set out in clause 6.7.5(c);
- clause 6.7.5(c) requires that Aurora's Negotiating Framework must meet 10 specified minimum requirements (detailed below in section 34.4); and
- clause 6.7.5(d) requires that Aurora's Negotiating Framework must not be inconsistent with any of several specified requirements of Chapter 5 of the *Rules*.

Consistent with the requirements of the *Rules* Aurora has prepared a Negotiating Framework to apply to its *Negotiated Distribution Services*, that is, to its New Public Lighting Technology services. The provisions of the Negotiating Framework are summarised in this chapter at a high level, whilst the Negotiating Framework itself is appended as an attachment to this *Regulatory Proposal*. Aurora considers that its Negotiating Framework is compliant with the above *Rules* requirements.

34.2. Negotiated Distribution Services

Aurora anticipates that it will provide one *Negotiated Distribution Service* for the 2012-17 *Regulatory Control Period*, being its New Public Lighting Technology services[1]. These services relate to the provision of public lighting for pilot studies of new public lighting technologies. The Negotiating Framework will apply only to the negotiations undertaken in respect to the terms and conditions of access to these services, and has been developed to accommodate the nature of this service.

This classification of new public lighting technology services as a *Negotiated Distribution Service* is consistent with the AER's position which is set out in its *Framework and Approach* paper for Aurora. The AER considered that the inability to determine charges for these services upfront meant that classification as *Direct Control Services* was not practical. On this basis, the AER's likely approach to classifying new public lighting technologies is as a *Negotiated Distribution Service*.

New public lighting technology services were unregulated in the 2008-12 *Regulatory Control Period*. These services have been delivered by Aurora in respect to a small trial involving three LED light fittings. This trial is being conducted with the Kingborough Council to establish a benchmark for the potential future deployment of the LED light fittings within that council. This is a joint trial and is being funded by both Aurora and the Kingborough Council.

1 AER, Final Framework and approach paper, Aurora Energy Pty Ltd, Regulatory Control Period commencing 1 July 2012, 27 November 2010 page 39, 61.

In view of the limited range of energy efficient public lighting options currently available, Aurora considers that there is significant potential for a more diverse range of new technologies to be piloted during the 2012-17 *Regulatory Control Period*. Aurora will apply it's Negotiating Framework when negotiating the terms and conditions of its involvement in public lighting technology pilots with customers such as local governments.

34.3. Outline of Negotiating Framework

Aurora developed its Negotiating Framework with regard to both the requirements of the *Rules*; and to the specific nature of New Public Lighting Technology services. Notably, New Public Lighting Technology services will comprise public lighting installations provided by Aurora for trials and pilots of luminaires that are not currently offered by Aurora.

The Negotiating Framework therefore accommodates Aurora's requirement for preliminary information about the trial technology in order to evaluate:

- compatibility of the proposed public lighting technology with its network and business requirements;
- impact on the current lighting product range;
- capital, installation, maintenance and other life cycle costs;
- compliance with AS/NZS 3000:2007, AS/NZS 1158 and any other relevant standards; and
- any other technical aspects such as electrical data and availability of components.

The Negotiating Framework consequently sets out a requirement for the preliminary evaluation of the public lighting technology, before commencing negotiations regarding the terms and conditions of access. This means that Aurora has assurance regarding the suitability of the technology prior to commencing detailed negotiations in relation to pilot testing.

An overview of Aurora's Negotiating Framework is set out in Table 131.

Table 131

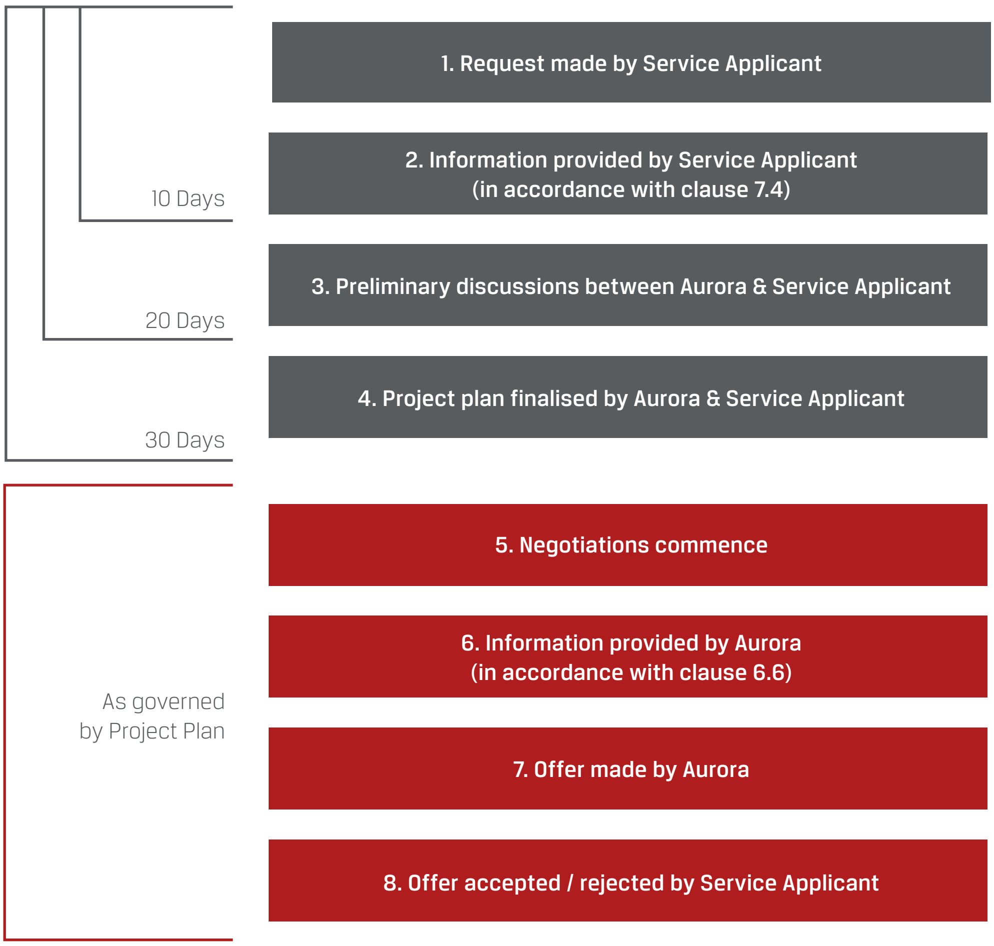
Provisions of Aurora's Negotiating Framework

Clause	Summary
1. *Rules*	This clause provides a general description of the requirements of the *Rules* and the requirement for Aurora to prepare its Negotiating Framework.
2. *Negotiated Distribution Services*	This clause sets out the *Negotiated Distribution Services* to be offered by Aurora during the 2012-17 *Regulatory Control Period* (new public lighting technology services).
3. Application of Negotiating Framework	This clause provides a general description of the application of the Negotiating Framework, including a description of the parties to which it applies (Aurora and any Service Applicant) and provisions in the event of any inconsistency between the document and the *Rules*.
4. Written request for service	This clause set out the requirement to submit a written application requesting a *Negotiated Distribution Service* to Aurora.
5. Negotiate in good faith	This clause requires Aurora and the Service Applicant to negotiate in good faith for the terms and conditions of access to a *Negotiated Distribution Service*.
6. Provision of commercial information to Service Applicant	This clause provides for requests for commercial information from Aurora by the Service Applicant, and requires Aurora to provide the Service Applicant with prescribed information pertaining to the cost of providing a *Negotiated Distribution Service*.
7. Provision of commercial information to Aurora	This clause provides for requests for commercial information from the Service Applicant by Aurora, and for confidentiality requirements relating to the provision of any information.
8. Provision of Confidential Information	This clause sets out confidentiality requirements relating to the provision of any confidential information to either party.
9. Process and timeframes	This clause sets out the process and timeframes for negotiating the terms and conditions of access to a *Negotiated Distribution Service*.
10. Suspension of timeframe	This clause sets out suspension provisions setting out when negotiation timeframes may be suspended in specified circumstances.
11. Dispute resolution	This clause provides that disputes between Aurora and a Service Applicant must be dealt with in accordance with the dispute resolution process of Chapter 6 the *Rules*.
12. Payment arrangements	This clause provides that the Service Applicant may be required to pay the direct expenses incurred by Aurora in processing the application for a *Negotiated Distribution Service*.
13. Impact on other Distribution Network Users	This clause requires that Aurora determine the potential impact of the *Negotiated Distribution Service* on other Distribution Network Users and notify and consult with any affected Distribution Network Users.
14. Results of negotiations	This clause requires that Aurora must publish the results of negotiations for access on its website.
15. Definitions and interpretation	This clause provides the definitions that are to apply in the Negotiating Framework

A schematic overview of the processes and timeframes set out under clause 9 of the Negotiating Framework is set out in Figure 39.

Figure 39

Negotiating Framework Processes and Timeframes



34.4. Compliance with Rules Requirements

Aurora considers that the Negotiating Framework submitted as part of this *Regulatory Proposal* is compliant with the requirements of the *Rules*. Table 132 sets out the section of the Negotiating Framework that gives effect to the *Rules*.

Table 132

Negotiating Framework compliance with Rules

Rules	***Rules* Requirement**	**Negotiating Framework**
6.7.5(c)(1)	A requirement that the provider and a Service Applicant negotiate in good faith the terms and conditions of access to a *Negotiated Distribution Service*.	Clause 5
6.7.5(c)(2)	A requirement that the provider to provide all such commercial information a Service Applicant may reasonably require.	Clause 6.2
6.7.5(c)(3)	A requirement that the provider: • identify and inform a *Service Applicant* of the reasonable costs and/or the increase or decrease in costs of providing the *Negotiated Distribution Service*; and • demonstrate to a Service Applicant that the charges for providing the *Negotiated Distribution Service* reflect those costs and/or the cost increment or decrement (as appropriate); and • have appropriate arrangements for assessment and review of the charges and the basis on which they are made	Clause 6.5
6.7.5(c)(4)	A requirement that the Service Applicant provide all commercial information the provider may reasonably require.	Clause 7.2 Clause 7.4
6.7.5(c)(5)	A requirement that negotiations with a Service Applicant for the provision of the *Negotiated Distribution Service* be commenced and finalised within specified periods, and that each party make reasonable endeavours to adhere to the specified time limits.	Clause 9.2
6.7.5(c)(6)	A requirement that disputes as to the terms and conditions of access for the provision of *Negotiated Distribution Services* are to be dealt with in accordance with the relevant provisions of the Law and the *Rules*.	Clause 11.1
6.7.5(c)(7)	A requirement for payment by a Service Applicant of the provider's reasonable direct expenses.	Clause 12.2 Clause 12.3
6.7.5(c)(8)	A requirement that the Distribution Network Service Provider determine the potential impact on other Distribution Network Users.	Clause 13.1
6.7.5(c)(9)	A requirement that the Distribution Network Service Provider must notify and consult with any affected Distribution Network Users.	Clause 13.2
6.7.5(c)(10)	A requirement that the Distribution Network Service Provider publish the results of negotiations on its website.	Clause 14.1
6.7.5(d)	A requirement that the Negotiating Framework must not be inconsistent with any of the requirements of clauses 5.3, 5.4A, 5.5 and Chapter 6.	Clause 3.4
6.7.5(e)	A requirement that each Distribution Network Service Provider and Service Applicant who is negotiating for the provision of a *Negotiated Distribution Service* by the provider must comply with the requirements of the negotiating framework in accordance with its terms.	Clause 3.2
6.7.6(a)(1)	A provision that commercial information provided to a Service Applicant does not include confidential information provided to the Distribution Network Service Provider by another person.	Clause 8.1 Clause 8.2
6.7.6(a)(2)	A provision that commercial information be provided to a Service Applicant may be provided subject to a condition that the Service Applicant must not provide any part of that commercial information to any other person without the consent of the Distribution Network Service Provider.	Clause 8.1 Clause 8.2
6.7.6(b)(1)	A provision that commercial information to be provided to a Distribution Network Service Provider does not include confidential information provided to a Service Applicant by another person.	Clause 8.1 Clause 8.2
6.7.6(b)(2)	A provision that commercial information be provided to a Distribution Network Service Provider may be provided subject to a condition that the provider must not provide any part of that commercial information to any other person without the consent of the Service Applicant.	Clause 8.1 Clause 8.2

35. Confidential Information

35. Confidential Information

35.1. Claim for confidentiality

Clause 6.8.2(c)(6) of the *Rules* requires Aurora to provide an indication of the parts of this *Regulatory Proposal* Aurora claims to be confidential and wants excluded from publication.

Certain information provided in documents accompanying this *Regulatory Proposal* is confidential and Aurora therefore requests that it be treated as such by the AER and not published.

35.2. Confidential Attachments

Aurora claims confidentiality over certain attachments identified in the table of Attachments to this *Regulatory Proposal* on the grounds that such attachments:

(1) contain information that is not common knowledge or publicly available;

(2) contain information of a commercial value that would be reduced or destroyed by any disclosure;

(3) concerns the lawful commercial financial affairs of Aurora and the disclosure of that information could unreasonably affect Aurora;

(4) contains information about a third party, which Aurora is not authorised to disclose;

(5) contains trade secrets;

(6) contains information that is the intellectual property of Aurora;

(7) constitute internal working documents; and/or

(8) contain information which may injure the public interest if disclosed.

No information contained in the body of this *Regulatory Proposal* is information which Aurora considers to be confidential. Aurora has set out the basis of its claims for confidentiality over the attachments in the table of attachments to this *Regulatory Proposal*, including completed RIN templates and information provided by Aurora in response to the RIN issued by the AER.

36. Indicative Pricing

36. Indicative Pricing

Clause 6.8.2 (c)(4) of the *Rules* requires indicative prices for *Direct Control Services* for each year of the *Regulatory Control Period*.

This chapter provides an outline of Aurora's methodology and assumptions used to determine indicative prices for *Standard Control Services* for the forthcoming *Regulatory Control Period*.

36.1. Control mechanism

The AER's control mechanism for Aurora, as prescribed in the AER's Framework and Approach paper for *Standard Control Services,* is consistent with Aurora's current regulatory arrangements. This requires Aurora to:

- apply a fixed revenue cap control mechanism;
- determine ARR using a building block approach; and
- determine usage-based prices that are calculated for specific services in accordance with recovering at least avoidable cost but no more than stand-a-lone costs for each service plus daily or fixed charges.

36.2. Carry-over of adjustments

In accordance with Chapter 6 of the *Rules,* the building blocks are specified in clause 6.4.3(a)(6) with respect to any carry-over amounts from previous determinations. For the purposes of determining annual revenue requirements, Aurora has assumed no carry-over amounts will apply. Any carry-over amounts arising from the current *Regulatory Control Period* will be calculated and submitted as part of Aurora's 2012 Pricing Proposal.

36.3. Annual revenue requirement

Annual smoothed revenue for *Standard Control Services* has been determined in accordance with the building block approach detailed in chapter 30 of this *Regulatory Proposal* and as calculated in the AER's PTRM.

36.4. Energy consumption forecasts

Aurora's total energy consumption has experienced an unprecedented decline over the past two years. A full econometric approach is currently being undertaken by ACIL Tasman to assess the underlying drivers of the decline and to determine the most appropriate growth factors for forthcoming *Regulatory Control Period.*

For the purpose of determining indicative prices for the forthcoming *Regulatory Control Period,* Aurora has applied an interim methodology for projecting energy consumption forecasts using actual consumption data over the current and previous *Regulatory Control Periods* with a range of growth factors applied to determine forecast consumption. Final consumption forecasts will be provided pending the completion of the econometric analysis by ACIL Tasman.

36.5. Indicative prices

For the purposes of determining indicative prices Aurora has adopted an approach of segregating total network sales by the following customer classes:

- residential;
- small business – LV;
- large business – LV;
- large commercial – HV;
- irrigation; and
- unmetered supplies.

Separate consumption forecasts have been produced for each customer class.

Table 133 provides an indication of distribution prices for *Standard Control Services* by customer class. These prices have been calculated using energy consumption forecasts and annual revenue requirements at the customer class level.

Table 133

Indicative prices (nominal cents)

Customer Class	2012-13 (c/kWh)	2013-14 (c/kWh)	2014-15 (c/kWh)	2015-16 (c/kWh)	2016-17 (c/kWh)
Residential	7.41	7.52	7.65	7.75	7.86
Small business – LV	9.24	9.37	9.52	9.64	9.76
Large business – LV	4.82	4.86	4.89	4.91	4.93
Large commercial – HV	1.23	1.25	1.26	1.28	1.29
Irrigation	6.77	6.89	6.97	7.09	7.12
Unmetered supplies	8.29	8.38	8.47	8.55	8.64

Indicative prices have been shown in nominal cents per kWh for energy consumed, however, it is noted that actual prices depend on specific tariffs which are made up of additional components including fixed, energy and demand charges. For this reason the above prices are considered indicative only, are not binding and are for the purposes of providing a high level overview of the expected price impact for the forthcoming *Regulatory Control Period* only.

Actual prices for the forthcoming *Regulatory Control Period* will be determined following the submission and approval of Aurora's annual Pricing Proposal to the AER in accordance with clause 6.18.7 of the *Rules*.

All indicative prices are exclusive of GST.

37. Certification Statement

37. Certification Statement

In accordance with clauses S6.1.1(5) and S6.1.2(6) of the *Rules*, Aurora is required to lodge a *Regulatory Proposal* that contains a certification by two directors of Aurora as to the reasonableness of the key assumptions that underlie the forecasts of capital and operating expenditure.

This certification statement is consistent with the form required in the RIN and is appended as an attachment to this *Regulatory Proposal*.

38. CEO's Statutory Declaration

38. CEO's Statutory Declaration

38. CEO's statutory declaration

In accordance with the RIN served on Aurora by the AER the CEO of Aurora is required to verify that:

- the information and documentation provided to the AER in accordance with the RIN is complete in all material respects; and
- the information and documentation provided to the AER in accordance with the RIN is accurate in all material respects and can be relied upon by the AER to assess the *Regulatory Proposal* submitted by Aurora to the AER in order to make a Distribution Determination for Aurora.

This statutory declaration is consistent with the form required in the RIN and is appended as an attachment to this *Regulatory Proposal*.

Table of Attachments
Listing of figures and tables
Glossary of terms/abbreviations

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Glossary of terms/abbreviations

Table of Attachments

Document ID	Document name	Confidentiality claim clause	Confidential
AE001	Certification Statement		No
AE002	CEO's Statutory Declaration		No
AE003	Aurora Green (policy)		No
AE004	Aurora Safe (policy)		No
AE005	Aurora Health (policy)		No
AE006	Information Management Policy	35.2(1); 35.2(6); 35.2(7)	Yes
AE007	Aurora Procurement Policy	35.2(1); 35.2(2); 35.2(3); 35.2(8)	Yes
AE008	Aurora Capitalisation Policy	35.2(1); 35.2(2); 35.2(3); 35.2(8)	Yes
AE009	Draft – Aurora Distribution Customer Capital Contributions Policy	35.2(1); 35.2(2); 35.2(3); 35.2(6); 35.2(7); 35.2(8)	Yes
AE010	Aurora Asset Management Plan	35.2(1); 35.2(3); 35.2(7); 35.2(8)	Yes
AE011	Aurora Corporate Plan	35.2(1); 35.2(2); 35.2(3) ; 35.2(6); 35.2(8)	Yes
AE012	Aurora Strategic Plan	35.2(1); 35.2(2); 35.2(3) ; 35.2(6); 35.2(8)	Yes
AE013	Aurora Distribution Network ISG Strategy 2012 – 2017	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(6); 35.2(8)	Yes
AE014	Customer Strategy	35.2(1)	Yes
AE015	Strategic Fleet Asset Management Plan	35.2(1); 35.2(2); 35.2(3); 35.2(7)	Yes
AE016	Distribution Business Strategy		No
AE017	Network Management Strategy	35.2(1); 35.2(2); 35.2(3); 35.2(6); 35.2(7); 35.2(8)	Yes
AE018	Management Strategy Bushfire Mitigation	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(8)	Yes
AE019	Management Strategy Vegetation Management	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(8)	Yes
AE020	Reliability Strategy 2010	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE021	Management Strategy 2011 Network Metering	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE022	Property and Accommodation Strategy	35.2(1); 35.2(2); 35.2(3); 35.2(7)	Yes
AE023	Management Plan 2011 - System Operations	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE024	Management Plan 2011 - Protection and Control	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE025	Management Plan 2011 - Reliability	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE026	Management Plan 2011 - Power Quality	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE027	Management Plan 2011 - Zone Substations	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE028	Management Plan 2011 – High Voltage Regulators	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE029	Management Plan 2011 – Underground System	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE030	Management Plan 2011 – Overhead System and Structures	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE031	Management Plan 2011 – Ground Mounted Substations	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE032	Management Plan 2011 - Customer Initiated Capital Works	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE033	Management Plan 2011 - Capacity	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE034	Management Plan 2011 – Demand Management	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE035	Management Plan 2011 – Connection Assets	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE036	Management Plan 2011 – Metering Assets	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE037	Management Plan 2011 – Public Lighting	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE038	Management Plan 2011 – Vegetation Management	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE039	Management Plan 2011 – Bushfire Mitigation (general programs)	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes

Table of Attachments

Document ID	Document name	Confidentiality claim clause	Confidential
AE040	Management Plan 2011 – Bushfire Mitigation (asset programs)	35.2(1); 35.2(3); 35.2(6); 35.2(8)	Yes
AE041	Facilities Management Plan December 2010	35.2(1); 35.2(2); 35.2(3); 35.2(7)	Yes
AE042	Deliverability Plan – Network Services	35.2(1); 35.2(2); 35.2(3); 35.2(7)	Yes
AE043	Aurecon System Strategic Planning Capacity Report – Executive Summary	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE044	Aurecon System Strategic Planning Capacity Report – Central	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE045	Aurecon System Strategic Planning Capacity Report – East Coast	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE046	Aurecon System Strategic Planning Capacity Report – Hobart East	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE047	Aurecon System Strategic Planning Capacity Report – Hobart West	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE048	Aurecon System Strategic Planning Capacity Report – North Coast	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE049	Aurecon System Strategic Planning Capacity Report – North East	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE050	Aurecon System Strategic Planning Capacity Report – North West	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE051	Aurecon System Strategic Planning Capacity Report – Sorell	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE052	Aurecon System Strategic Planning Capacity Report – South	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE053	Aurecon System Strategic Planning Capacity Report – Tamar	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE054	Aurecon System Strategic Planning Capacity Report – West Coast	35.2(1); 35.2(2); 35.2(4); 35.2(7)	Yes
AE055	Futura Report – Proposed Non-network Initiatives	35.2(1); 35.2(2); 35.2(4); 35.2(6); 35.2(8)	Yes
AE056	ACIL Tasman Load Forecasting Methodology	35.2(1); 35.2(4); 35.2(6)	Yes
AE057	ACIL Tasman Load Forecast	35.2(1); 35.2(4)	Yes
AE058	ACIL Tasman New Customer Connections Forecasts	35.2(1); 35.2(4); 35.2(6);	Yes
AE059	ACIL Tasman Energy Forecast Review & Audit Report	35.2(1); 35.2(4)	Yes
AE060	Aurora Consumption Model (Energy Forecast)	35.2(1); 35.2(2); 35.2(6); 35.2(7)	Yes
AE061	Parsons Brinckerhoff Capex & Opex Benchmarking Study		No
AE062	Benchmark Economics Report (Benchmarking)		No
AE063	GHD Bushfire Mitigation Strategy Review	35.2(1); 35.2(2); 35.2(3); 35.2(8)	Yes
AE064	Legislation Aurora must comply with		No
AE065	Negotiating Framework		No
AE066	Cost of Capital 2012 – 2017 Electricity Distribution Revenues	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(8)	Yes
AE067	Cost Allocation Methodology (CAM)		No
AE068	Deloitte's Corporate & Shared Services Cost Allocation Methodology Study	35.2(1); 35.2(3); 35.2(7); 35.2(8)	Yes
AE069	Tax Asset Base (Deloitte's Report)	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(6)	Yes
AE070	KPMG Audit Report on Aurora Energy Regulatory Models	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(8)	Yes

Document ID	Document name	Confidentiality claim clause	Confidential
AE071	SKM Report – Aurora Energy Annual Material Cost Escalators	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(8)	Yes
AE072	Public Lighting Annuity Model – Architecture Paper	35.2(1); 35.2(3); 35.2(6); 35.2(7)	Yes
AE073	Other Revenue Adjustments Methodology	35.2(1); 35.2(6); 35.2(7)	Yes
AE074	Quoted Services Methodology	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(6); 35.2(7)	Yes
AE075	Units Rates Model Procedure	35.2(1); 35.2(2); 35.2(6); 35.2(7)	Yes
AE076	Metering Annuity Model Procedure Manual	35.2(1); 35.2(2); 35.2(3); 35.2(4); 35.2(6); 35.2(7)	Yes
AE077	Fee Based Services Model Procedure Manual	35.2(1); 35.2(3); 35.2(7)	Yes
AE078	Post Tax Revenue Model (PTRM)	35.2(1); 35.2(2); 35.2(3); 35.2(8)	Yes
AE079	Roll Forward Model (RFM)	35.2(1); 35.2(2); 35.2(3); 35.2(8)	Yes
AE080	Public Lighting Annuity Model	35.2(1); 35.2(2); 35.2(3); 35.2(6); 35.2(7)	Yes
AE081	Metering Annuity Model	35.2(1); 35.2(2); 35.2(3); 35.2(6); 35.2(7)	Yes
AE082	Excluded Services Model	35.2(1); 35.2(2); 35.2(3); 35.2(6); 35.2(7)	Yes
AE083	Aurora's Proposed Program of Work	35.2(1); 35.2(2); 35.2(3); 35.2(6); 35.2(7); 35.2(8)	Yes

Listing of figures and tables

Figures within this Regulatory Proposal

Tables within this Regulatory Proposal

Glossary of terms/abbreviations

Term	Definition
2003 Determination	Investigation into Electricity Supply Industry Pricing Policies Declared Electrical Services Pricing Determination, 27 November 2003
2004-07 *Regulatory Control Period*	The *Regulatory Control Period* commencing on 1 January 2004 and concluding on 31 December 2007
2007 Determination	Investigation into Electricity Supply Industry Pricing Policies Declared Electrical Services Pricing Determination, 10 December 2007
2008-12 *Regulatory Control Period*	The *Regulatory Control Period* commencing on 1 January 2008 and concluding on 30 June 2012
2012-17 *Regulatory Control Period*	The *Regulatory Control Period* commencing on 1 July 2012 and concluding on 30 June 2017
AARR	Aggregate Annual Revenue Requirement
ARR	Annual Revenue Requirement
ABS	Australian Bureau of Statistics
ACG	The Allen Consulting Group Pty Ltd
ACIL Tasman	ACIL Tasman Pty Ltd
ACS	*Alternative Control Services*
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AETV	Aurora Energy Tamar Valley Pty Ltd
AMI	Accredited Meter Installer
API	Application program interface
ARR	Annual Revenue Requirement
ATO	Australian Taxation Office
AUD	Australian Dollars
Aurora	Aurora Energy Pty Ltd
BAF	Aurora's budgeting and forecasting tool
BARC	Board Audit Review Committee
Bairnsdale Power Station	The power station operated by Alinta Energy Limited in Victoria's East Gippsland
CablePI	Safety device provided by Aurora to detect broken neutrals
CAIDI	Customer Average Interruption Duration Index
CAM	Cost Allocation Method
Capex	Capital Expenditure
CFC	Construction Forecasting Council
CMD	Coincident Maximum Demand
CONAN	Contingency analyser – an API developed by Hill Michael Strategic Engineering to analyse switching capacity on Aurora's distribution network.
CONSAC	Concentric Sheath Aluminium Conductor
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CSC	Customer Support Centre
CT	Current Transformer
DAIS	Distribution Asset Information System
DCS	*Direct Control Services*
Deloitte	Deloitte Touche Tohmatsu Limited
DIER	Department of Infrastructure, Energy and Resources

Term	Definition
DINIS	Distribution Network Information System produced by Fujitsu
DMIA	Demand Management Incentive Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DPIPWE	Department of Primary Industries, Parks, Water and Environment
DSM	Demand Side Management
DUOS	Distribution Use of System
EBSS	Efficiency Benefits Sharing Scheme
EDO	Expulsion Drop Out
EHV or Extra High Voltage	Voltages of 88 kV and above
EIS&A Act	*Electricity Industry Safety and Administration Act 1997*
EMS	EMS Solution Pty Ltd
Enterprise Architects	Enterprise Architects Pty Ltd
EPA	Environmental Protection Authority division within DPIPWE
ESC	Essential Services Commission of Victoria
ESI Act	*Electricity Supply Industry Act 1995*
ESIA Act	*Electricity Supply Industry Administration Act 2007*
Expert Panel	The panel formed by the Tasmanian Government in accordance with the provisions of the Expert Panel Act
Expert Panel Act	*Electricity Supply Industry Expert Panel Act 2010*
EY	Ernst and Young Global Limited
EziKey	EziKey Pty Ltd, a fully owned subsidiary of Aurora
FLRS	Feeder Load Reporting System
FRAMME	Facilities Rulebase Application Model Management Environment
FTE	Full Time Equivalent
GHD	GHD Pty Ltd
GI	Galvanised Iron
GIS	Graphical Information System
GLAD	Greater Launceston Are Upgrade
GSL	Guaranteed Service Level
GSP	Gross State Product
G-Tech	Intergraph's G-Technology GIS
GW	Gigawatt
GWh	Gigawatt Hour
HASU	Hobart Area Supply Upgrade
HES	Hobart Eastern Shore
HIA	Housing Industry Association Ltd
HV or High Voltage	Voltages between 6.6 kV and 66 kV
Hydro or HEC	Hydro Electric Corporation or Hydro Electric Commission
ICAM	Indirect Cost Allocation Model
ICS	Incident Control System
Intergraph	Intergraph Corporation Pty Ltd
InService	Intergraph's Outage Management System
ISG	Information Services Group, a department of the Commercial Services division of Aurora
ISO 9001	Part of the ISO 9000 family of quality management system standards published by the International Organisation for Standardisation
ITAA	Income Tax Assessment Act 1997

Glossary of terms/abbreviations

Term	Definition
km	Kilometre
KPMG	KPMG Cooperative International
kV	Kilovolt
kVA	Kilovolt Amp
kW	Kilowatt
kWh	Kilowatt Hour
LED	Light Emitting Diode
LV or Low Voltage	Voltages of 415 volts or less
MAIFI	Momentary Average Interruption Frequency Index
MCE	Ministerial Council on Energy
MD	Maximum Demand
MDMS	Market Data Management System
MED	Major Event Day
MEPS	Minimum Energy Performance Standards
MIL	Market Integration Layer
MV	Megavolt
MVA	Megavolt Amps
MW	Megawatt
MWh	Megawatt Hour
NBN	National Broadband Network
NBNCo	NBN Co Limited
NBN Tasmania	NBN Tasmania Limited
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NER or *Rules*	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NPV	Net Present Value
NTER	National Tax Equivalent Regime
NVA	Natural Values Atlas
OEPC	Office of Energy Planning and Conservation within DIER
OH	Overhead
Ombudsman Act	*Energy Ombudsman Act 1998*
OMS	Outage Management System
Opex	Operating Expenditure
OTTER	Office of the Tasmanian Economic Regulator
PAMA	Public Authority Management Agreement
PAYG	The Aurora Retail pay as you go package offered to electricity customers
PB	Parson Brinckerhoff
PCB	Polychlorinated Biphenyl
POE	Probability of Exceedence
POEL	Private Overhead Electricity Line
POW	Program of Work
Price Control Regulations	*Electricity Supply Industry (Price Control) Regulations 2003*
PTRM	Post Tax Revenue Model
PwC	PricewaterhouseCoopers International Limited

Term	Definition
RAB	Regulated Asset Base
RBA	Reserve Bank of Australia
Regulator	The meaning given in the *Economic Regulator Act 2009*
Regulatory Proposal	The meaning given in the *Rules*
RFM	Roll Forward model
RIN	Regulatory Information Notice
Ring Fencing Guideline	Guideline for Ringfencing in the Tasmanian Electrcity Supply Industry, October 2004
Rules	National Electricity Rules
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCS	*Standard Control Services*
SF_6	Sulphur Hexafluoride
SHE	Safety, Health and Environment
SHEC	Safety, Health, Environment and Compliance
SKM	Sinclair Knight Merz Pty Ltd
Smart meter	An electrical meter that records consumption in intervals of 30 minutes or less and communicates that information back to Aurora.
SOM	Service Order Management
SORI	Statement of Regulatory Intent
SSL	Solid State Lighting Technologies
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
Tamar Valley Project	Aurora's completion of the partially completed Babcock and Brown power station at Bell Bay.
TEC	Tasmanian Electricity Code
TER	Tax Equivalent Regime
TESI	Tasmanian Electricity Supply Industry
TMR	Trunk Mobile Radio
TNSP	Transmission Network Service Provider
ToU	Time of Use
Transend	Transend Networks Pty Ltd
Tribunal	Australian Competition Tribunal
TRIP	Aurora's Targeted Reliability Improvement Program
TUOS	Transmission Use of System
TVD	Telephony Video Data or TVD Incorporated
US$	United States Dollars
VCR	Value of Customer Reliability
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
WASP	Works Asset Scheduling and Programming software package developed by EMS Solutions Pty Ltd
WH&S Act	*Workplace Health and Safety Act 1995*
Wilson Cook	Wilson Cook and Company Limited
WireAlert	The trading name adopted by EziKey
WST	Workplace Standards Tasmania