2016–2020 Price Reset

Appendix E
Capital expenditure

April 2015

CitiPower
2016–2020 Price Reset
Capital expenditure

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1 Summary

CitiPower plans to invest around $850 million of capital expenditure over the 2016–2020 regulatory control period.

The capital expenditure forecasts have been carefully prepared to ensure that CitiPower will be able to continue to deliver a reliable supply of electricity at least cost to customers, including at times of peak demand on the network, as well as to connect new customers and to meet regulatory obligations.

This chapter sets out CitiPower's forecasts for capital expenditure for standard control services for the 2016-2020 regulatory control period.

Capital expenditure is required to continue to meet expected demand and connect new customers and to safely deliver a reliable electricity supply to customers, with the appropriate power quality, while striving to maintain the load at risk and health of the network assets. In addition, CitiPower is required to undertake activities to mitigate the risk of its assets starting a fire.

As demonstrated in the benchmarking chapter, CitiPower is one of the most efficient distributors in Australia. The rigorous cost controls and condition-based approach to maintaining assets has resulted in a reliable electricity supply at low cost.

CitiPower has asked its stakeholders their views on the business, to better understand their priorities and concerns. In terms of feedback, generally the stakeholders:

- are satisfied or very satisfied with the current level of reliability;[1]
- do not want an increase in their electricity bill except to reduce the risk of fire danger arising from the network by undergrounding electricity assets in areas of natural beauty;[2]
- are supportive of creating a smarter grid, which further utilises the information available from smart meters to enable CitiPower to better manage and react to changes in the network;
- have a strong desire for investment and upgrades to the network to support the use of renewable energies;[3] and
- seek access to their energy consumption data to enable them to make more informed choices about their usage patterns and investment options.

CitiPower has taken the stakeholder views and expectations into account in developing its expenditure forecasts for the 2016–2020 regulatory control period, which are set out in table 1.1.

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1 For example, see Colmar Brunton Research, CitiPower Stakeholder engagement research – online customer survey results, 18 July 2014, p. 36

2 Colmar Brunton Research, *CitiPower Stakeholder engagement research – online customer survey results*, 18 July 2014, p. 50.

3 For example, Colmar Brunton Research, *CitiPower Stakeholder engagement research report, residential customer focus groups and SME customer interviews*, 30 April 2014, p. 15.

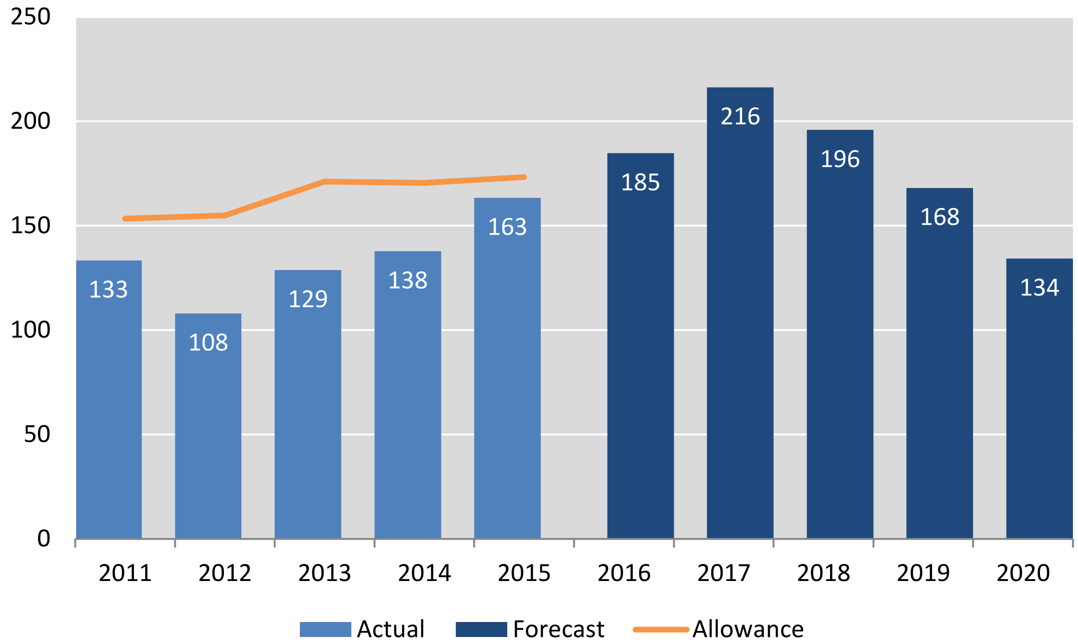
Table 1.1 Total capital expenditure ($ million, 2015)

	2016	2017	2018	2019	2020	Total
Replacement	48.9	50.0	62.5	57.3	41.3	260.0
Augmentation	38.9	62.6	42.9	24.3	11.2	179.9
Connections	71.6	71.0	63.9	62.4	63.1	332.1
VBRC	0.6	2.6	2.2	2.3	2.1	9.8
IT and communications	18.6	18.7	17.3	15.3	11.2	81.1
Non-network	6.1	11.4	7.0	6.5	5.5	36.5
Equity raising costs	2.3	-	-	-	-	2.3
Gross direct capital expenditure	**187.1**	**216.3**	**195.9**	**168.2**	**134.3**	**901.8**
Plus direct overheads	17.4	18.1	18.8	19.3	19.9	93.5
Gross capital expenditure	**204.5**	**234.4**	**214.6**	**187.5**	**154.2**	**995.3**
Less customer contributions	31.5	34.1	28.0	25.8	25.4	144.9
Less disposals	-	-	-	-	-	-
Net capital expenditure	**173.0**	**200.3**	**186.6**	**161.7**	**128.8**	**850.4**

Source: CitiPower

CitiPower requires an increase in capital expenditure from the current regulatory control period. The profile of actual and forecast gross capital expenditure is shown in figure 1.1.

Figure 1.1 CitiPower total gross direct capital expenditure 2011–2020 ($2015, million)[4]



Source: CitiPower
Note: excludes equity raising costs

The capital expenditure chapter is set out as follows:

- section 2 provides general information that is application to all categories of CitiPower's forecast capital expenditure;
- section 3 describes the process for identifying assets that need replacement, as well as the replacement expenditure forecasts;
- section 4 describes the process for planning network augmentation and methodology for forecasting augmentation expenditure;
- section 5 sets out the process for forecasting expenditure for connections and customer-driven works;
- section 6 outlines the expenditure required as a result of the recommendations from the Victorian Bushfires Royal Commission (**VBRC**);
- section 7 discusses expenditure for information technology (**IT**) and communications;
- section 8 discusses forecasts for non-network expenditure; and
- section 9 relates to the interactions of capital and operating expenditure.

1.1 Overview of historical expenditure

CitiPower's capital expenditure program during the 2011–2015 regulatory control period has delivered reliable electricity supply at an efficient cost.

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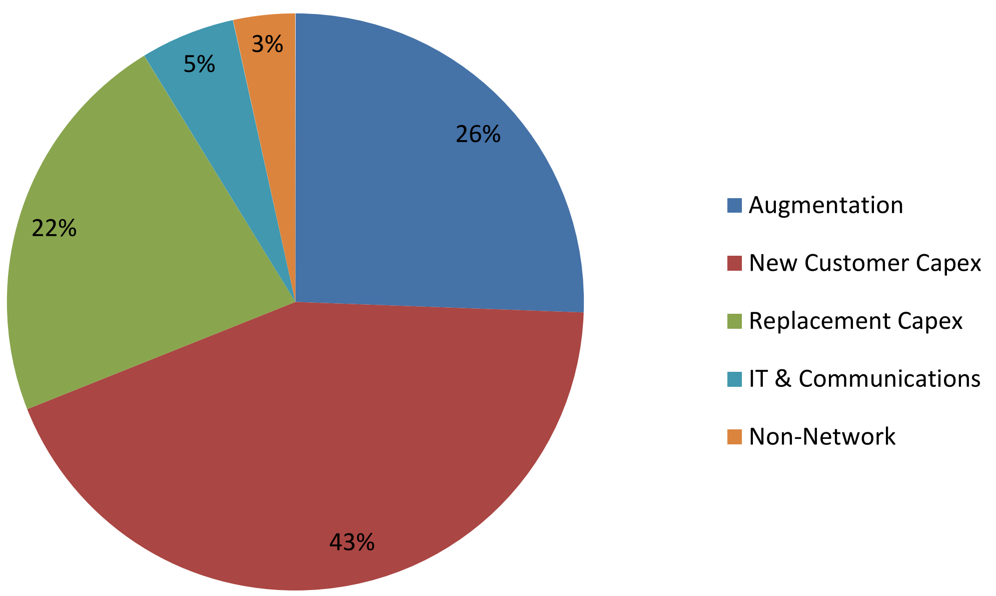
[4] 2006 to 2014 are actual costs, 2015 to 2020 are forecast costs.

The largest proportion of gross capital expenditure was spent on new connections, as shown in figure 1.2. To date, CitiPower had connected over 15,000 net additional customers to its network, in addition to customer driven works through relocations and redevelopments. This includes connections for new commercial and residential high-rise developments in the Docklands area, redevelopment of Melbourne Park and the Emporium shopping complex, as well as high and medium density housing in inner Melbourne.

Augmentation was the second largest expenditure category, where CitiPower has continued to progress the Central Business District (**CBD**) Security Upgrade and Metro projects which will provide greater resilience to the network in the Melbourne CBD and inner suburbs.

Replacement expenditure to maintain the reliability of the network was the third largest expenditure category, where CitiPower has continued to provide a network that is available over 99.98 per cent of the time.

Figure 1.2 Capital expenditure by category in the current regulatory control period



Source: CitiPower
Note: excludes equity raising costs

CitiPower has underspent the Australian Energy Regulator's (**AER's**) gross direct capital expenditure allowance for the current control period by approximately 18 per cent.

The underspend demonstrates that CitiPower has responded to the incentives within the regulatory regime to invest efficiently to provide safe, reliable and secure supply of electricity.

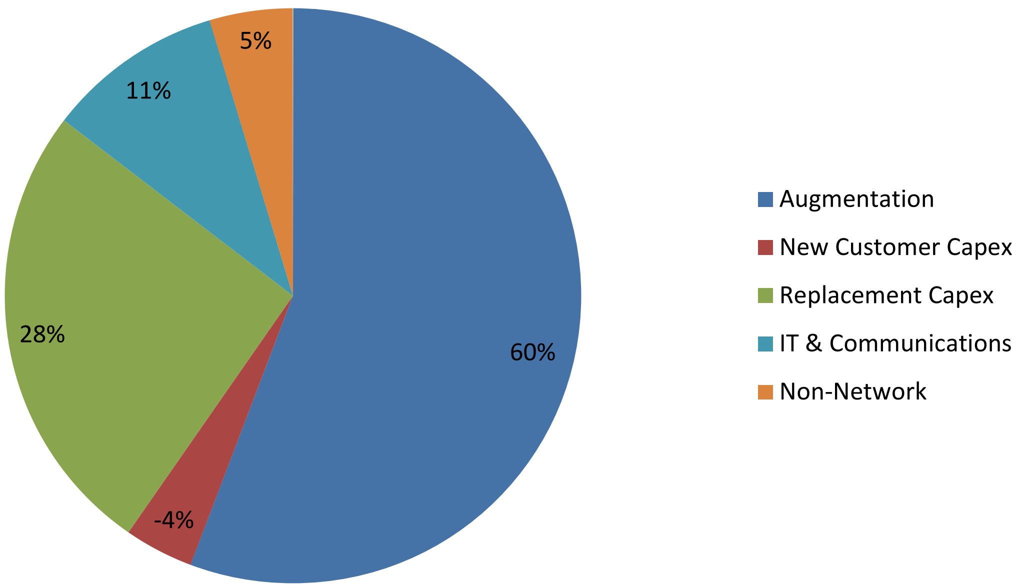
The majority of the underspend was in the category of augmentation, as shown in figure 1.3. There were two drivers for this underspend:

- delays to the CBD Security Upgrade and Metro projects as a result of community and local government objections to the planning permit for the upgrade to the Brunswick Terminal Station (**BTS**); and
- lower than expected levels of growth in peak demand.

The delayed upgrade to BTS also had knock-on impacts to other related projects, including replacement works at zone substations.

Figure 1.3 shows how each capital expenditure category contributed to the overall underspend against the AER allowance. Overspend of the AER allowance is denoted as a negative contribution.

Figure 1.3 Contribution of capital expenditure categories to underspend



Source: CitiPower
Note: excludes equity raising costs

It is also noted that the category of IT and communications only included expenditure approved by the AER through the 2010 distribution determination. In the 2011-2015 regulatory control period, CitiPower received an allowance for the continued deployment of Advanced Metering Infrastructure (**AMI**) under an Order In Council issued by the Victorian Government. This program diverted resources and focus from other business activities.

Greater detail on the underspend or overspend is provided in the description of each capital expenditure category in this appendix.

Impact of falling energy consumption

Debate around falling energy consumption leading to an expected decline in network expenditure is not that relevant to CitiPower.

The changes in energy consumption are reflected in the peak demand forecasts, and the relationship between annual energy and peak demand is reflected through the annual load duration curves (**LDC**'s). In deciding when to undertake a major augmentation project, the LDC is used in calculating the amount of energy at risk not being supplied to customers in the event of a failure of an asset in the network. In accordance with the requirements of the regulatory test regime, CitiPower will only undertake a major augmentation of the network if there is a high enough value of energy at risk to necessitate extra network capacity.

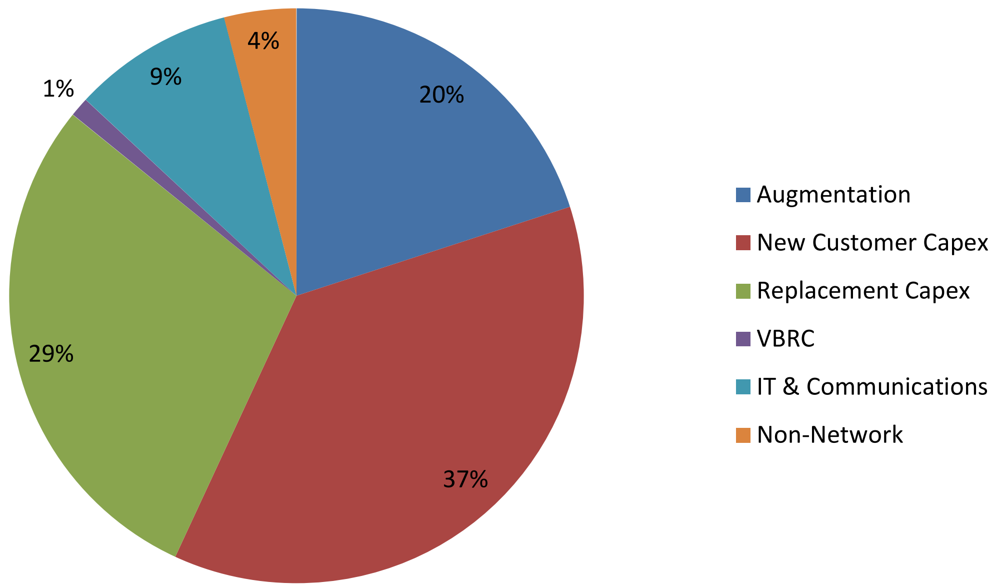
Augmentation expenditure is not a large part of CitiPower's overall capital expenditure. In the current regulatory period, 26 per cent of total capital expenditure related to augmentation works. The majority of augmentation expenditure was driven by the obligation to increase resilience of the network in the inner areas of Melbourne including the CBD.

For the 2016–2020 regulatory control period, CitiPower expects to spend only 20 per cent of capital expenditure on augmentation works, with one third of the expenditure driven by a need to address peak demand constraints on the network.

1.2 Proposed capital expenditure

CitiPower has determined the amount of capital expenditure that is needed during the 2016–2020 regulatory control period to continue to provide a safe and reliable electricity supply to customers, while also meeting its regulatory obligations. The breakdown by capital expenditure category is shown in figure 1.4.

Figure 1.4 Forecast capital expenditure by category



Source: CitiPower
Note: excludes equity raising costs

The largest category of capital expenditure is expected to continue to be related to new customer connections. The second largest category of expenditure is expected to be for replacements. Augmentation, VBRC, IT and non-network expenditure together are around one third of the total forecast for capital expenditure.

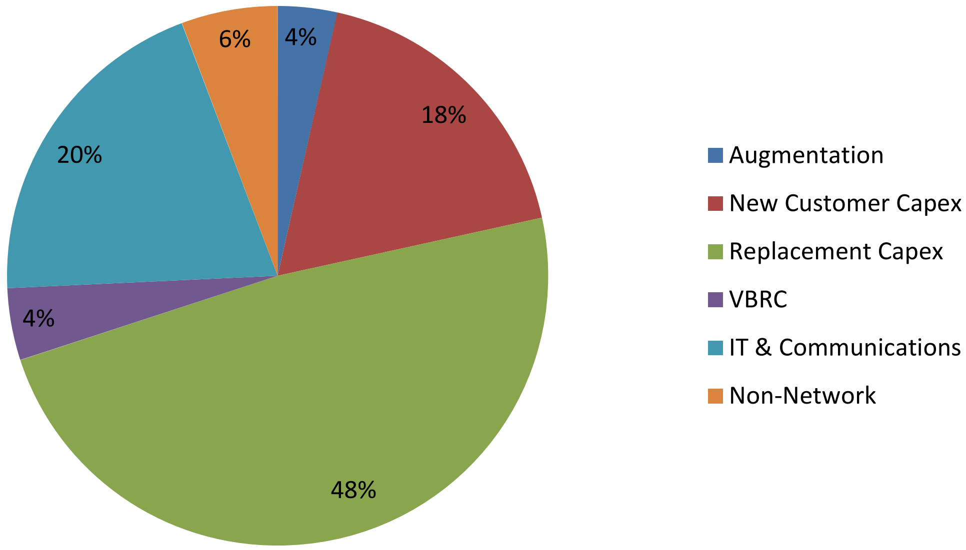
CitiPower requires a 34 per cent increase in gross direct capital expenditure for standard control services for the 2016–2020 regulatory control period, compared to the actual expenditure during the current regulatory control period.

The increase in expenditure is primarily driven by the following factors:

- rebuilding and refurbishment of zone substations in line with the CBD Security Works program, which was delayed as a result of the BTS delay;
- completing the augmentation works related to the CBD Security Upgrade and Metro projects following the granting of the BTS planning permit;
- connections and customer-driven works associated with specific urban renewal projects;
- IT expenditure to deliver a smarter network, as well as replace the existing billing system to support Power of Choice initiatives and innovative tariff offers.

Figure 1.5 shows the percentage contribution by capital expenditure category of the increase in expenditure for the 2016–2020 regulatory control period compared with the current regulatory period.

Figure 1.5 Contribution of capital expenditure categories to forecast increase



Source: CitiPower
Note: excludes equity raising costs

Additionally, the forecasts include expenditure to allow CitiPower to continue to innovate on the network as its moves towards a smarter grid, where consumers are empowered to make choices about their energy consumption which ultimately will drive investment in, and drive development of, the electricity distribution sector. This expenditure partly explains the increase in forecast for IT and communications systems.

CitiPower's forecasts are discussed in more detail in each section of this appendix.

Innovative expenditure

During the 2016–2020 regulatory control period, CitiPower intends to undertake innovative initiatives on the network which draws upon recent technological advancements to enable better interaction with, and provision of improved service to, customers. The innovations include:

- retiring and decommissioning the ageing 22kV sub-transmission network supplied from West Melbourne Terminal Station. Rather than replace the ageing 22kV network on a 'like-for-like' basis, CitiPower will take a different and lower cost approach by integrating these customers into the 66kV sub-transmission network;
- control schemes at select zone substations to balance available capacity and prospective fault currents and enable connection of some medium scale embedded generation;
- sophisticated analytics to dynamically manage the network using the energy consumption data available from smart meters;
- improved customer response to localised outages via direct communication to each smart meter; and
- managing assets more efficiently by remote condition diagnostics and condition alerts.

2 General matters applicable to all capital expenditure categories

This section provides an overview of general matters which relate to all capital expenditure categories, including a high level overview of the forecasting methodology and the deliverability of the network-related works.

2.1 Categorisation of expenditure

CitiPower's capital expenditure forecasts have been broken down into the following categories of expenditure, as set out in the AER's Expenditure Forecast Assessment Guideline:[5]

- replacement;
- augmentation;
- connection and customer driven works; and
- non-network.

An additional category has been included for recommendations as a result of the VBRC. The requirements imposed on CitiPower generally require the installation of new equipment into the network, and thus do not align with the AER's categories of replacement of existing equipment, or augmentation resulting in the increase in capacity of the network. The separate categorisation of VBRC may also assist the AER in comparison of this regulatory proposal against forecast expenditure in other jurisdictions.

The non-network category noted above is further disaggregated into the following sub-categories, again using the categories set out in the AER's Expenditure Forecast Assessment Guideline:[6]

- IT and communications;
- motor vehicles;
- property;
- other; and
- Supervisory Control and Data Acquisition (**SCADA**) and network control.

The IT and communications category contains a significant amount of expenditure. As a result, this expenditure is discussed separately from the remaining categories of non-network expenditure in this appendix.

The AER's Regulatory Information Notice (**RIN**) issued for the purposes of making a distribution determination for the regulatory control period from 1 January 2016 to 31 December 2020 (**Reset RIN**) requires some expenditure to be classified in different categories from those identified above. For example, expenditure for field based devices and communications fibre that form part of the SCADA network are included Template 2.3 of the Reset RIN which relates to augmentation expenditure. CitiPower has therefore only included the non-field based costs associated with the SCADA network in the non-network capital expenditure.

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[5] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, p. 57.

[6] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, p. 196.

Similarly, VBRC expenditure is contained within Template 2.3 of the Reset RIN relating to augmentation, with the exception of multi-circuit rebuilds which are included in the replacement expenditure categories in the Reset RIN.

CitiPower has completed the Reset RIN in the manner prescribed by the AER.

Capitalised overheads

Direct overheads, which are overhead costs directly related to operating the network such as the control room or local network planners and management, are calculated using the 'revealed cost approach' that is used for forecasting operating expenditure. That is, the actual direct overheads incurred in 2014 are escalated for the 2016–2020 regulatory control period using the scale escalators identified in the operating expenditure chapter of the Regulatory Proposal.

CitiPower does not consider that there is any reasonable scope for ambiguity in categorisation of direct overheads.

These costs are applied to all capital expenditure categories with the exception of IT and communications, motor vehicle, property and other.

2.2 Forecasting approach

This section overviews the approach used to forecast capital expenditure, as well as addressing high level matters associated with the forecasts.

2.2.1 Preparation of forecasts

In preparing the capital expenditure forecasts, CitiPower notes that:

- the preparation of capital expenditure forecast was consistent with the budgetary, planning and governance processes used in the operation of the business;
- rigorous checks were made to the forecasts, including reviews by subject matter experts, senior managers and the General Manager of the respective business unit; as well as other quality assurance steps to ensure that the amounts are free from error;
- rigorous checks were made to the various models used in preparing the forecasts, including reviews by external consultants where appropriate; and
- the forecasts are consistent with the requirements for prudency and efficiency of capital expenditure, and thus when the resulting amounts are translated into the estimated impact on the future electricity bill of customers (per section 13.9 of the regulatory proposal), any price increases are minimised to ensure the expenditure is in the long term interests of consumers.

The forecasts for capital expenditure have been properly allocated to standard control services in accordance with the principles and policies in CitiPower's approved Cost Allocation Method (**CAM**).

The forecasts have also been prepared to ensure that CitiPower continues to comply with its regulatory obligations. The obligations, and their relevance to the regulatory proposal, are listed in Reset RIN Template 7.3. In some cases, this appendix discusses how the obligations that have been taken into account in the preparation of the forecasts.

A range of source material has been used in developing the forecasts, including asset management plans, and planning policies and guidelines. These various documents are listed in Reset RIN Template 7.1 and are attached to the regulatory proposal. The RIN discusses the relevance of the documents to the regulatory proposal, and in some cases, this appendix discusses where they have been applied in developing the forecasts for each category of capital expenditure.

In addition, economic analysis and/or technical reports have been obtained from consultants to assist in preparing, or reviewing, the forecasts. These reports are attached to the regulatory proposal and are discussed in each relevant category of capital expenditure in this appendix.

Models containing quantitative data that have been used in the preparation of the capital expenditure forecast are attached to this regulatory proposal. The models contain detail of the calculations that have been made to generate data provided in the regulatory templates. It is noted that the base capital expenditure models contain direct cost data only, and escalations and other factors are subsequently overlaid through other models before the final capital expenditure numbers are presented.

The key assumptions underpinning the capital expenditure forecasts are set out in the *Certification of reasonableness of key assumptions* attachment. The reasonableness of the key assumptions that underlie CitiPower's expenditure forecasts was certified by the Board of Directors. This certification is provided within the attachment.

CitiPower considers that its forecast total capital expenditure is required to achieve the capital expenditure objectives. The way in which the total forecast capital expenditure meets the capital expenditure objectives, criteria and factors in set out in appendix D.

2.2.2 Forecasting outputs

Historical and forecast capital expenditure is contained in the consolidated capital expenditure forecast model, provided in the *CP capex consolidation* model. The forecasts comply with the requirements of the Reset RIN.

The *CP capex consolidation* model contains CitiPower's capital expenditure for each regulatory year between 2006 and 2014 and its expected capital expenditure for 2015 categorised in the same way as the capital expenditure forecast for the 2016–2020 regulatory control period and separately identifying for each regulatory year between 2006–2015:

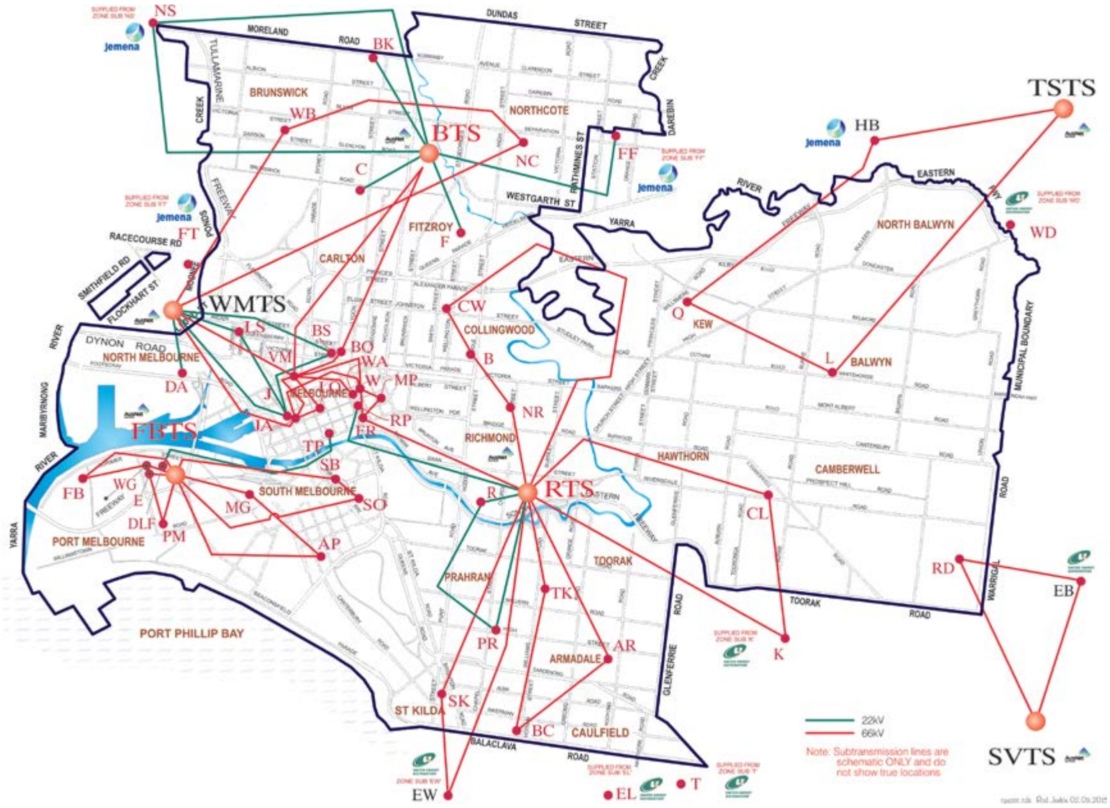
- margins paid or expected to be paid by CitiPower in circumstances where those margins are referable to arrangements that do not reflect arm's length terms; and
- expenditure that should have been treated as operating expenditure in accordance with the current capitalisation policy for that regulatory year.

CitiPower's *Capitalisation Policy* is attached.

2.2.3 Material assets

The location of CitiPower's material assets, in particular zone substations and sub-transmission lines, is shown in figure 2.1.

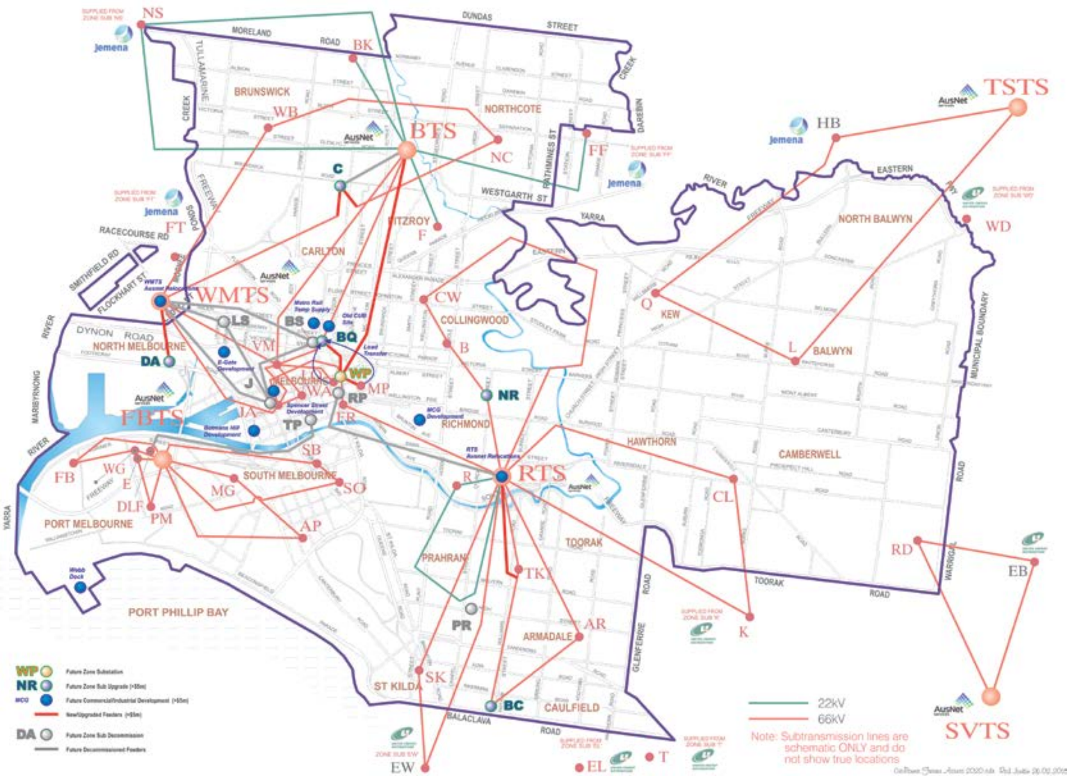
Figure 2.1 Map of CitiPower's material assets



Source: CitiPower

At the end of the 2016–2020 regulatory control period, the network will have been augmented and new connections added, to meet demand and customer requirements over the period. A map which highlights the expected changes to the network and shows all proposed material assets is shown in figure 2.2 below.

Figure 2.2 Map of CitiPower's expected network at the end of 2020



Source: CitiPower

The notable changes to the network map include:

- decommissioning of the 22kV sub-transmission network originating at the West Melbourne terminal station (**WMTS**);
- completion of the security of supply project, and associated projects, in the Melbourne CBD and inner suburbs, resulting in the new Waratah Place (**WP**) zone substation and associated sub-transmission lines;
- following the upgrade of Brunswick terminal station (**BTS**) from 22kV to 66kV, new sub-transmission lines to connect BTS to WP and WMTS to Brunswick (**C**) zone substations; and
- new customer connections.

These projects for new network services or new connections requiring augmentation are described in greater detail in this appendix, together with the anticipated cost of these proposed assets.

2.2.4 Deliverability

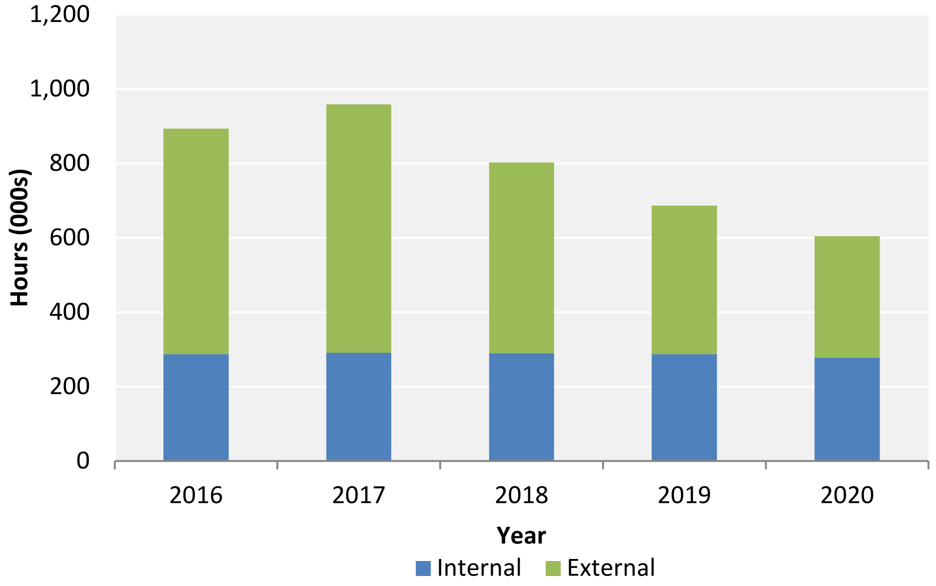
A deliverability plan has been developed to ensure that CitiPower is able to provide and deliver the necessary works over the 2016–2020 regulatory control period. The deliverability plan will utilise internal labour resources which will be supplemented, as required, by use of external subcontractors. CitiPower has established a number of arrangements to ensure that it can access external resources as required, including:

- long term panel contractors including preferred labour electrical and civil works suppliers; and
- access to agency and limited tenure personnel.

The mix between internal and external labour resources will be determined by, amongst other things, workload volumes, timing and locations; skills and competencies requirements; resource availability; peak period workloads; and labour rates for internal versus external resources.

The proposed deliverability plan for design and field services works, by work hours, is shown in figure 2.3.

Figure 2.3 Deliverability plan by internal and external labour capability



Source: CitiPower

Panel contractors provide a degree of flexibility in allocating resources to meet varying annual workload levels. These flexible arrangements enable CitiPower to minimise the costs of engaging external resources to assist in delivering the services that customers require.

Further information on how CitiPower optimises its labour resourcing using diverse contracting arrangements is discussed in appendix B.

3 Replacement expenditure

CitiPower is committed to taking a targeted and cost effective approach to the replacement and refurbishment of its assets. The approach is based on monitoring assets, and taking management based approach following any condition assessments, only replacing or repairing an asset when it is needed to maintain safety, reliability and/or security of supply.

In addition, CitiPower has one of the older networks in the National Electricity Market. While the majority of the assets were installed during the 1960s, 1970s and 1980s, the 22kV sub-transmission network was installed in the 1930s and the assets are progressively showing poor health. CitiPower will continue to decommission this network over time.

This section discusses CitiPower's historical and forecast replacement expenditure as well as the approach used in calculating the forecast expenditure.

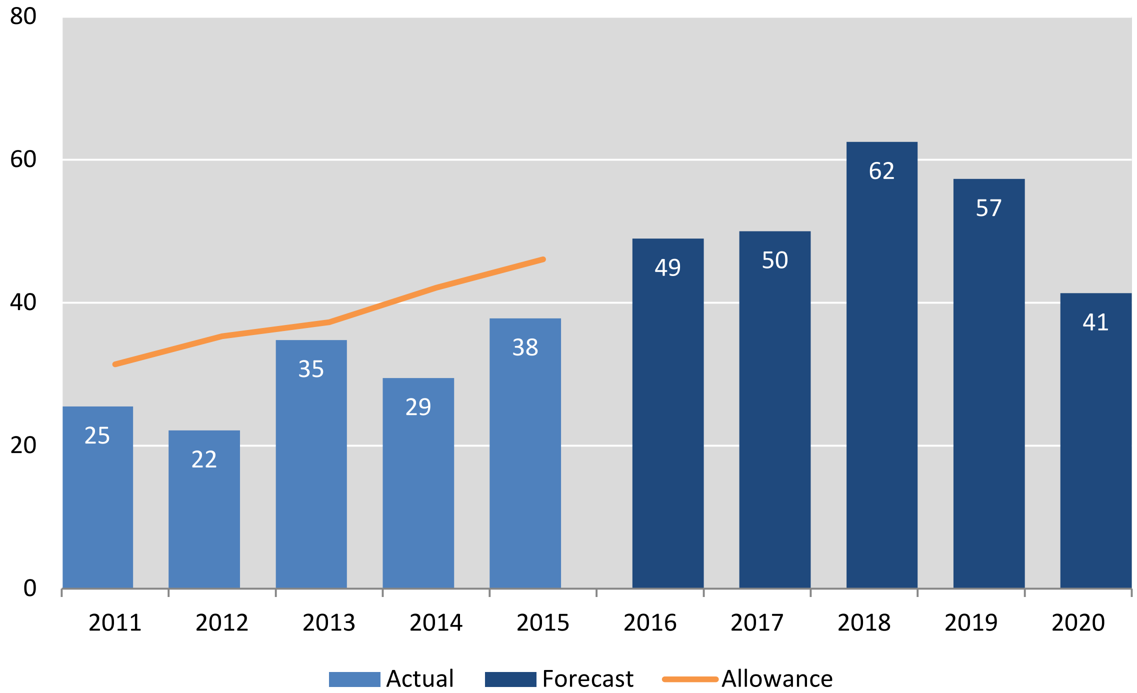
3.1 Overview

Replacement capital expenditure relates to the replacement of an asset with its modern equivalent or refurbishment to extend the life of an existing asset.

The category also includes routine replacement expenditure which was captured in the separate category of Environment, Safety and Legal (**ESL**) in the 2011–2015 regulatory control period. It includes replacement driven by environmental considerations such as noise abatement, drainage of oil, as well as electrical safety requirements. While ESL was previously a separate category, aside from the specific obligations arising from the VBRC the historical expenditure has been mapped to replacement category to enable comparisons between periods.

The profile of the actual and forecast expenditure over time is shown in figure3.1.

Figure 3.1 Replacement direct capital expenditure ($2015, million)



Source: CitiPower

The expenditure forecast is driven by:

- completing the refurbishment works intended to take place during the current regulatory period, but which have been delayed as a result of delays to the upgrade of Brunswick Terminal Station (**BTS**);
- age and condition of large plant and equipment; and
- increasing defect rate on poles and crossarms.

CitiPower has engaged with its stakeholders to understand their views on the need to replace assets to maintain reliability. Around eight out of ten customers indicated in the online survey that they are satisfied with the current level of reliability.[7] There was a clear preference by residential and small/medium enterprise (**SME**) customers for upgrades to old infrastructure to be made in ways that created future benefits, with particular mention of undergrounding rather than replacing old poles/wires and also a clear view that new developments should include undergrounding.[8]

> *They should invest to maintain the levels we have right now. There is no need to improve on them, they are good the way they are".*

> *The current levels are about right, if they can keep that up I would be happy".*

Source: Colmar Brunton Research, CitiPower Stakeholder Engagement Research Report – Residential customer focus groups and SME customer interviews, 30 April 2014, p. 27.

CitiPower's large customers consistently talked of the critical importance of continuous, uninterrupted, reliable supply of electricity to their organisation, with the implications of any interruption in supply of electricity representing a major cost to business, in terms of:[9]

- loss of production capacity;
- loss of human capital utilisation;
- risk to relationships (attached to failure to deliver in full on time);
- loss/perishing of inventory (i.e. refrigerated stock);
- loss attached to restarting machinery and/or production lines;
- risk to safety;
- loss of life (hospitals); and
- risk to local and international brand/reputation (entertainment sectors).

These customers had zero interest in reliability levels being reduced in return for cost savings, with the cost of electricity outages, or reduced reliability levels, being viewed as a far greater impost to their business.

3.2 Background information

This section describes the asset management process and CitiPower's methodology for forecasting replacement capital expenditure.

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7 Colmar Brunton Research, *CitiPower Stakeholder Engagement Research Online Customer Survey Results*, 18 July 2014, p. 42.

8 Colmar Brunton Research, CitiPower Stakeholder Engagement Research Report – Residential customer focus groups and SME customer interviews, 30 April 2014, pp. 30-31.

9 Colmar Brunton Research, *CitiPower Stakeholder Engagement Research Top 200 Customers In depth Interviews*, 22 July 2014, p. 14.

Replacement capital expenditure is primarily driven by the condition of the asset. That is, the asset is replaced when its condition deteriorates to a level that triggers its replacement in accordance with the internal asset management policies.

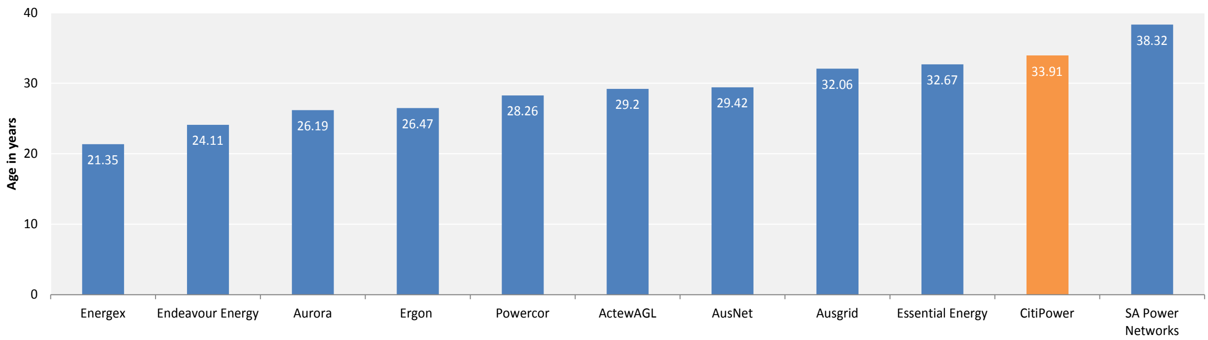
There are times, however, when other factors trigger the need for the asset to be replaced, such as technical obsolescence, environmental considerations or proactive programs to replace assets of a certain class to address safety related matters.

The need for asset replacement may also be considered alongside forecast changes in load growth for an area. Where CitiPower identifies a network constraint and replaces an asset to address the asset condition as well as increase the network capacity, then the expenditure would be categorised as augmentation. In contrast, where the replacement of the asset results in incidental augmentation, for example where like-for-like replacement may be more costly than replacement with a higher-capacity asset, then the expenditure would be categorised as replacement. That is, the identified need that drives the expenditure will determine the categorisation of the expenditure.

3.2.1 Key drivers for expenditure

CitiPower has one of the oldest networks in the National Electricity Market (**NEM**). This is shown in figure 3.2 where the average age of each network has been calculated by multiplying the number of assets in service each year by the asset age.

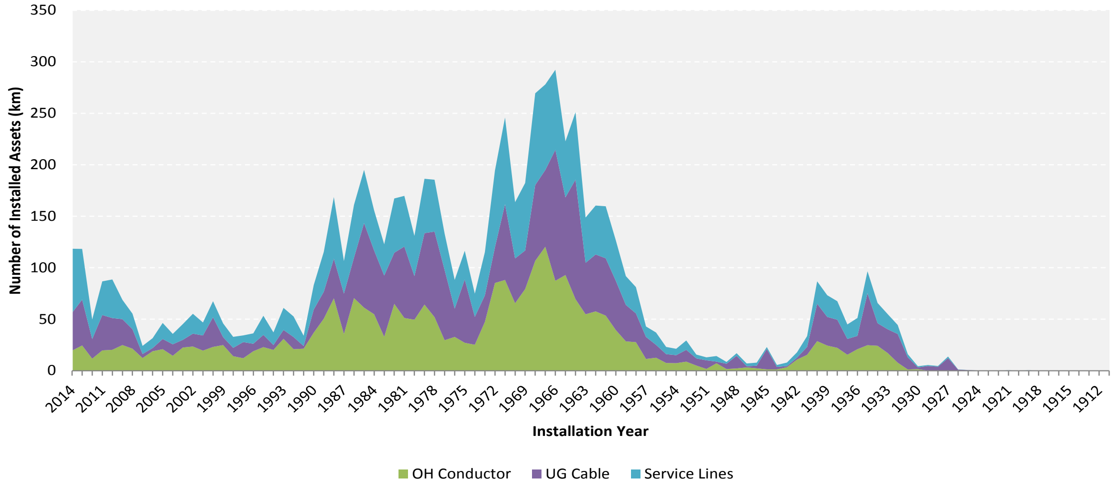
Figure 3.2 Average distribution network ages



Source: Category Analysis RIN, CitiPower analysis
Note: Jemena (incorrect format) and United Energy (inclusive of disposed assets) have been excluded from this analysis

The majority of CitiPower's assets were installed during the 1960s, 1970s and 1980s. This is shown in figure 3.3 containing the number of line assets installed (by kilometre) each year.

Figure 3.3 CitiPower lines asset age profile



Source: CitiPower

The graph also shows a number of assets installed in the 1930s. This is associated with the 22kV sub-transmission network in inner Melbourne that is intended to be decommissioned.

Age is not the sole determinant of the condition of CitiPower's assets. Other factors such as the operational history, operating environment, and manufacturing design and performance are also important in assessing their condition. That said, the age of the network will be a contributing factor to its overall condition and will increase the risk of failure.

3.2.2 Forecasting methodology

This section sets out the principles and processes underpinning CitiPower's two asset management methodologies, and the method for forecasting replacement capital expenditure using those methodologies.

The *Asset Management Framework* describes the principles of asset management that apply to all of CitiPower's network assets, and requires that all of the assets are maintained, refurbished or replaced in accordance with the asset management plans.[10]

The asset management framework aligns with the principles of PAS 55, which is the British Standards Institution's publicly available specification for the optimised management of physical assets.[11]

CitiPower's assets are subject to relevant condition assessment methods through planned inspection and monitoring programs. These programs have been developed taking into account regulatory obligations, industry knowledge as well as proven and established asset management methodologies.

CitiPower applies the following asset management methodologies to its network assets:

- reliability and safety based regime — this methodology is based on the principles of Reliability Centred Maintenance (**RCM**) together with regulatory obligations that are built into the asset management procedures. It is applied to routine replacement expenditure for higher volume

10 CitiPower, *Asset Management Framework*, 2015.

11 Available from http://www.bsigroup.com/en-AU/PAS-55-Asset-Management/.

and lower unit costs items of plant and equipment, such as poles, pole top-equipment, crossarms, insulators and batteries. The approach has regard for the asset age, condition and operating environment; and

- Condition Based Risk Management (**CBRM**) — this methodology is applied to assess the condition of assets, including the risk of the deterioration, of major items of plant, which involve significant and lumpy expenditure. This includes assets such as zone substation transformers and switchgear.

These are discussed in more detail in the sections below.

Poles and wires

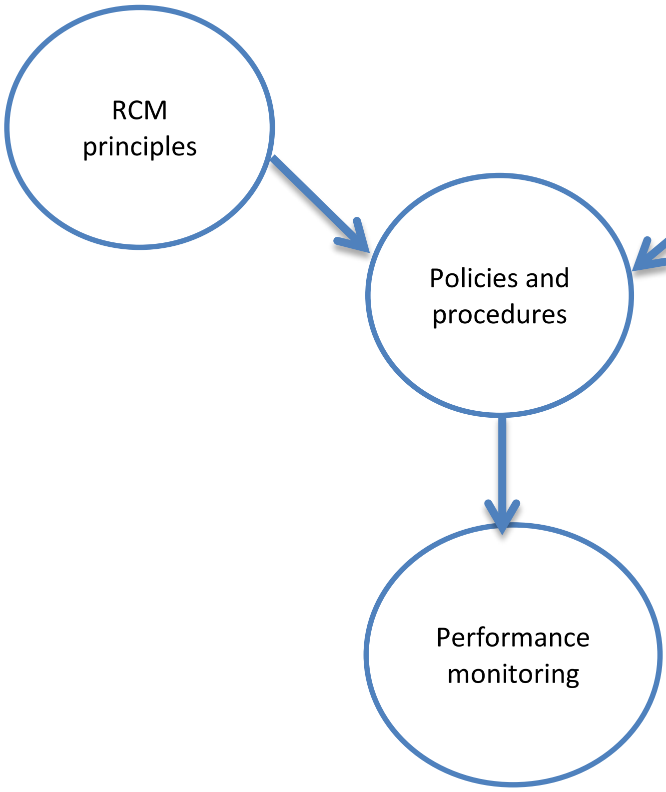
The reliability and safety based regime, based on RCM principles and regulatory obligations, is applied to high-volume plant and equipment such as poles, crossarms, conductors, protection relays as well as other assets poles and wires.

The process involves regular inspections of the assets, where defects are identified. A remedy is then applied to address the defect, which may consist of a maintenance solution or replacement of the asset.

Asset management policy

The asset management regime consists of RCM principles as well as relevant regulation obligations, as shown in figure 3.4.

Figure 3.4 Elements of the reliability and safety based maintenance regime



Source: CitiPower

At a high level, the RCM process is used to determine what must be done to ensure that any physical asset continues to operate to its intended performance.

The RCM process identifies each possible way in which a defect may occur in an asset, and the root cause of that defect. For each different type of defect, the possible impact on the safety, operations and other equipment in the network is assessed. Consequently, a maintenance strategy to address each type of defect is determined.

Where a defect is identified in an asset, then the maintenance strategy to address that defect is implemented. This may involve replacement of the asset, or maintenance measures to prolong the life of the asset, such as pole staking.

The RCM process can be summarised by a series of steps, as follows.

Figure 3.5 Steps in the RCM process

1. Select functions and performance standard of asset	• ensure the asset continues to do what its users want it to do • consider primary functions and secondary functions of asset
2. Identify function failures	• identify the ways in which the asset may fail to fulfil its functions
3. What causes each functional failure	• identify all of the events which are reasonably likely to cause each failed state • includes failures which have occured on the same or similar equipment; are prevented by existing maintainence procedures; and those which possibly may occur
4. What happens when failure occurs	• list all failure effects that describe what happens when a failure mode occurs, including supporting evidence • e.g. what is the evidence that a failure has occured, how does it pose a threat to safety or the environment
5. How does the failure matter	• consequences of failure of a hidden function, where failure will not become evident to operators under normal circumstances • consequence of failure of an evident function in terms of the impact on safety, environment, operational and non-operational matters
6. How to prevent or predict each failure	• identify the most appropriate maintenance strategy for each failure mode, which is also technically and economically feasible • where it is not possible to identify a pro-active task, select default actions such as proof testing, re-design or run to failure
7. Regularly review process	• once maintenance recommendations are put into practice, these are routinely reviewed and renewed as additional information is found

Source: CitiPower

RCM analysis is undertaken by taking into account the equipment manufacturer's recommendations, the physical and electrical environment in which the asset is installed, fault and performance data, test data, condition data, duty cycles as well as many years of field-based experience.

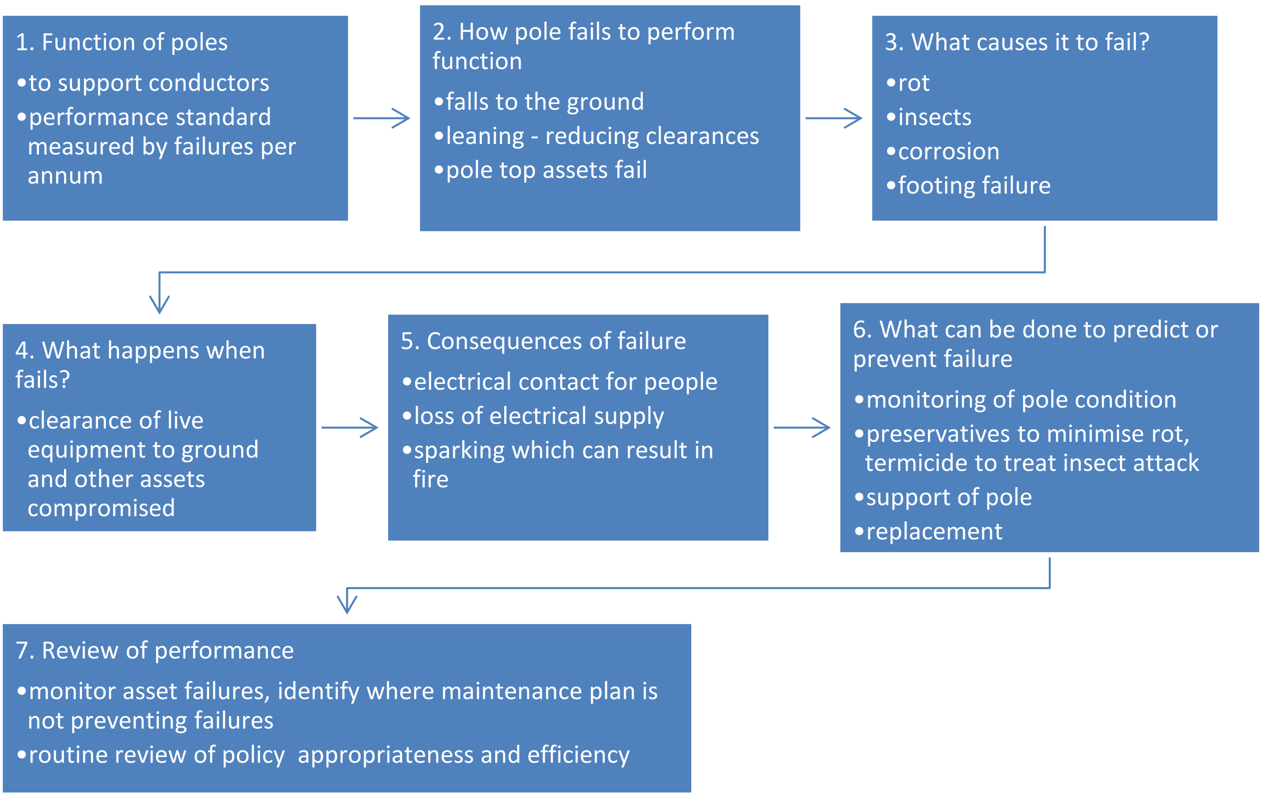
The combination of general maintenance requirements and the specific requirements based on the environments in which the assets operate may result in varying maintenance and condition monitoring regimes for the same type of asset. Tests and inspections are undertaken using tools such as thermal imagery, visual inspections, and invasive pole testing to assess asset condition.

Together with the relevant regulatory obligations, which for example may set out the inspection cycle, the resulting inspection and maintenance regimes form a comprehensive asset management system, which is documented through Technical Standards, asset management plans, maintenance policies, asset inspection manual and work instructions, which are embedded into CitiPower's corporate asset management enterprise system.

Maintenance policies are monitored through asset failure analysis and routinely reviewed to ensure the objectives of the maintenance regime are being achieved in terms of cost and asset performance. All maintenance and condition monitoring strategies are reviewed as a minimum once every five years.

A simplified example of how the RCM principles are applied to poles is shown in figure 3.6. CitiPower undertakes regular inspection of poles for diagnostic testing and monitoring of the assets to determine their relative performance and remaining life.

Figure 3.6 Example of how RCM principles are applied to poles



Source: CitiPower

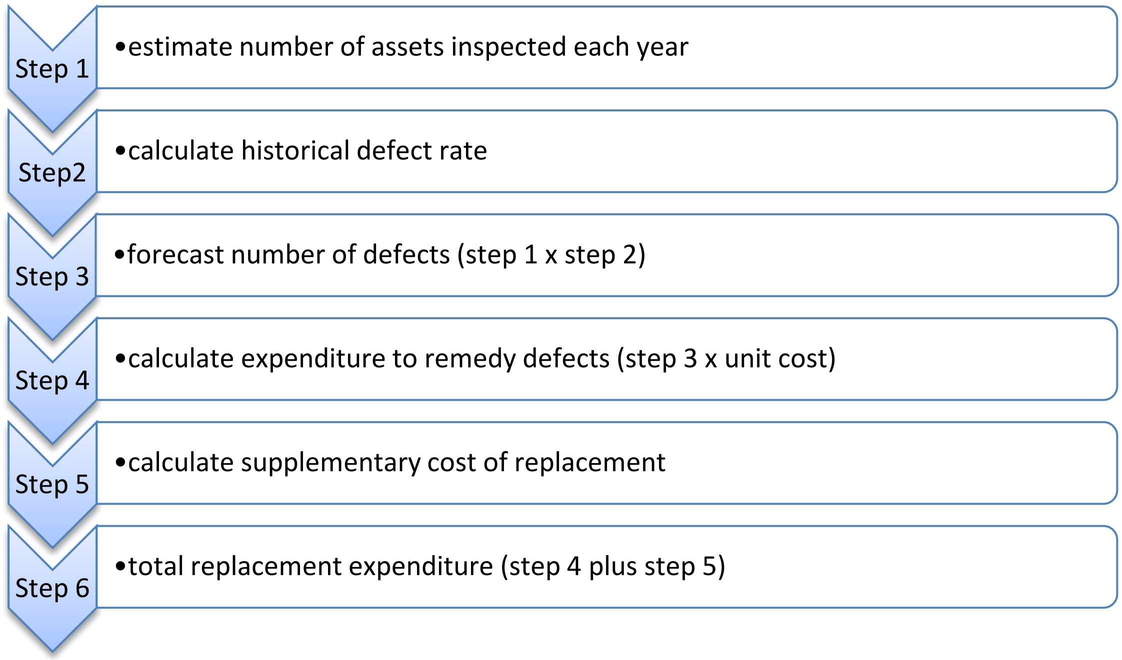
The performance of poles is monitored to highlight where the developed maintenance plan is not preventing failures. This may trigger a review of the RCM methodology, while taking into account any relevant regulatory obligations.

Routine review of the policy considers its appropriateness and efficiency, taking into account cost, industry developments, changed environmental conditions as well as failure and defect rates. That is, the review considers whether the policy is achieving its objectives.

Forecasting costs for 'poles and wires'

In forecasting the expenditure for 'poles and wires', the following process has been used:

Figure 3.7 Process for forecasting expenditure for smaller assets



Source: CitiPower

To understand how this process works in practice, an example is provided below of the forecasting methodology as it is applied to poles.

Step 1: to estimate the number of poles that will be inspected each year, the process primarily relies upon the observation and classification of defects through the routine inspections of poles and related assets. The number of poles inspected each year varies and thus the volume of defects identified.

Step 2: calculate the historical defect rate for each class of assets. In forecasting the number of replacements to be carried out in the 2016–2020 regulatory control period, CitiPower considers the annual and trend rates for various defect types on the assets.

CitiPower records the number of defects for each class of asset. Based on this information, CitiPower has been able to calculate the defect rate for pole replacement as a proportion of assets inspected.

Table 3.1 Pole replacement defect rates

	2009	2010	2011	2012	2013	2104
Defect rate	0.0071	0.0060	0.0082	0.0071	0.0090	0.0077

Source: CitiPower

Similarly, the defect rate for crossarms as a proportion of assets inspected has been increasing, as shown in table 3.2.

Table 3.2 Crossarm defect rate

	2009	2010	2011	2012	2013	2104
Defect rate	0.0264	0.0208	0.0638	0.0795	0.0777	0.056

Source: CitiPower

Step 3: to calculate the forecast number of defects, the number of defects likely to be observed in each year is calculated by multiplying the number of poles to be inspected in each year (step 1) with the defect rate (step 2).

Step 4: to calculate the expenditure associated with remedying the defects, the expenditure for replacing assets is calculated by multiplying the forecast number of defects (step 3) by the average unit cost of remedying the defect.

As replacement costs are captured at a project level, each of which contains multiple individual items of work to be completed, the average unit costs have been calculated by apportioning the total expenditure on replacement to these assets across the units of work recorded and completed. This is further discussed below.

Step 5: to calculate supplementary costs of replacement, it is noted that the unit costs used in step 4, above, do not capture all replacement costs associated with the works. For example, the costs do not capture earthing issues or installation of bird covers during the maintenance program.

Step 6: to calculate total replacement expenditure for RCM, this is calculated as the sum of the expenditure to remedy defects (step 4) plus the supplementary costs associated with the works (step 5).

Unit rates for assets managed under reliability and safety based regime

CitiPower does not collect unit cost information at a disaggregated asset level. Rather, CitiPower captures total costs for a program of work, and then allocates the costs to each function code. This is because it is more efficient for CitiPower to undertake several jobs on a single asset or on several assets when dispatched to the field, rather than completing an individual asset job and returning to the depot. This is discussed in the box below.

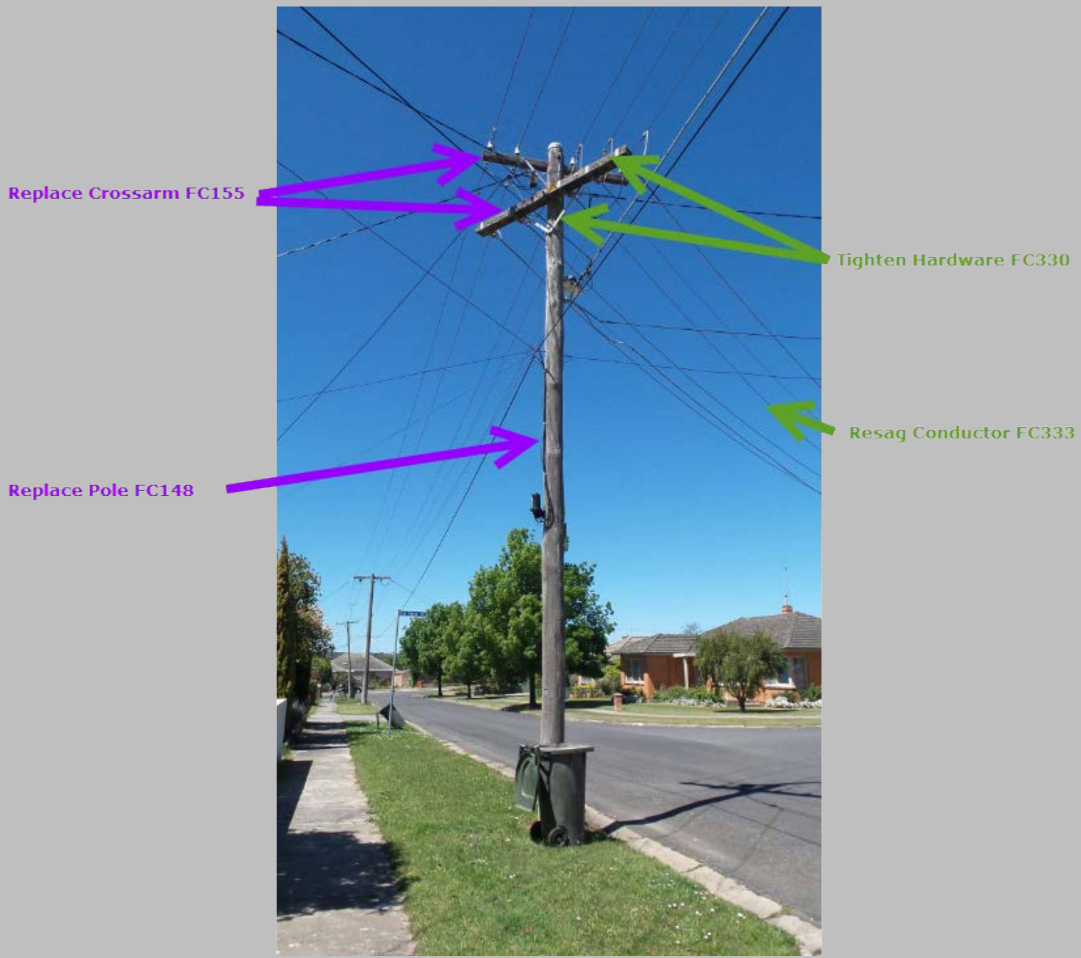
The average replacement cost per function code each is calculated by dividing the total costs allocated to the function code in the year by the total defect volumes reported for the function code in the year.

This average replacement rate per function code is used in the expenditure forecast. The average replacement rate is calculated as the average over the period from 2011 to 2014. This average replacement cost by function code is multiplied by the expected replacement rate for a category of assets each year, to determine the expenditure forecast. That is, the costs are based on actual historical costs for similar projects, where materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

Undertaking several jobs on a single asset

When a crew visits an asset location to undertake works, they rarely undertake a single activity. As shown in the picture below, the crew may replace the pole and the crossarm, and at the same time they may tighten the king bolt, resag the conductor, tighten the crossarm strap and replacement the insulator.

Figure 3.8 Mix of works undertaken at a single location



Source: CitiPower

It is clearly more practical and efficient for the raft of works to be undertaken in a single visit, rather than return visits for each activity.

Transformers and switchgear

Condition Based Risk Management (**CBRM**) is a structured process that combines asset information, engineering knowledge and practical experience to define future condition, performance and risk for network assets.

CitiPower applies the CBRM methodology to certain plant-based asset classes, namely transformers and circuit breakers.

Asset management

The CBRM methodology has been progressively developed over a number of years and has been successfully applied many times, helping distributors around the world to deliver effective asset related risk management. The CBRM process is extensively used by distributors in the United Kingdom, as well as other distributors in Australia such as SA Power Networks. The CBRM methodology that CitiPower uses has been developed by EA Technology.

The methodology draws upon CitiPower's knowledge and experience relating to degradation, failure, condition assessment, performance and influence of environment, duty, operational policy and specification of network assets. It is used to define current and future condition and performance of the assets.

The CBRM process can be summarised by a series of sequential steps, as follows:

Table 3.3 Steps in the CBRM process

Step	Description
1	**Define asset condition** Health indices are derived for individual assets within different asset groups. Health indices are described on a scale of 0 to 10, where 0 indicates the best condition and 10 the worst.
2	**Link current condition to performance** Health indices are calibrated against relative probability of failure (**PoF**). The HI/PoF relationship for an asset group is determined by matching the HI profile with the relevant observed failure rates.
3	**Estimate future condition and performance** Knowledge of degradation processes is used to trend health indices over time. This ageing rate for an individual asset is dependent on its initial HI and operating conditions. Future failure rates can then be calculated from aged HI profiles and the previously defined HI/ PoF relationship.
4	**Evaluation of potential interventions in terms of PoF and failure rates** The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled and the future HI profiles and failure rates reviewed accordingly.
5	**Define and weight consequences of failure (CoF)** A consistent framework is defined and populated in order to evaluate consequences in significant categories such as network performance, safety, financial, environmental, etc. The consequence categories are weighted to relate them to a common unit.
6	**Build risk model** For an individual asset, its probability and consequence of failure are combined to calculate risk. The total risk associated with an asset group is then obtained by summing the risk of the individual assets.
7	**Evaluate potential interventions in terms of risk** The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled to quantify the potential risk profile associated with different strategies.
8	**Review and refine information and process** Building and managing a risk based process based on asset specific information is not a one-off process. The initial application will deliver results based on available information and crucially, identify opportunities for ongoing improvement that can be used to build an improved asset information framework.

In terms of the steps in the process:

- steps 1 to 4 essentially relate to condition and performance and provide a systematic process to identify and predict end-of-life. Future expenditure plans can then be linked to probability of failure and failure rates;
- steps 5 to 7 deal with consequence of failure and asset criticality that are combined with PoF values to enable definition and quantification of risk; and
- step 8 is a recognition that building and operating a risk-based process using asset specific information is not a one-off exercise.

Each year, CitiPower updates the data in its CBRM model, which is contained in a MS Excel spreadsheet. CitiPower reviews the outputs of the CBRM which indicate the various replacement projects required, and identifies the projects that deliver the greatest risk reduction. The latter projects are determined by calculating the difference between the risk in a future year if the asset is not replaced and the risk that would result if the plant is replaced, and then assessing the various options to deliver the risk reduction.

While the CBRM methodology identifies a proposed year for the replacement of an asset, the project is then reviewed in conjunction with other augmentation and development plans in order to identify opportunities for synergies, such that the replacement schedule can coincide with other major works. The project is then captured within a future works plan.

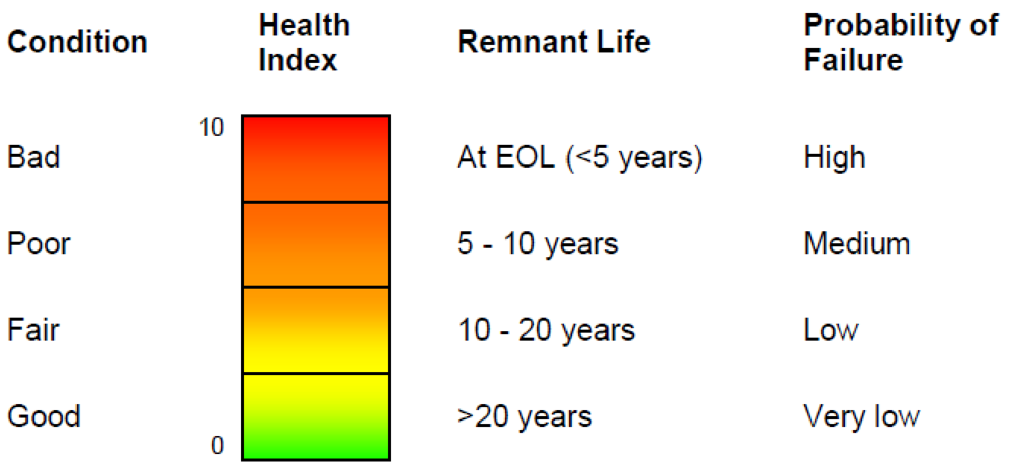
Prior to the project commencing, it is taken to the Capital Investment Committee (**CIC**) for a detailed review and to ensure that capital expenditure is targeted to deliver optimum outcomes for shareholders, customers, the community and employees.

Further detail regarding the key parameters in the CBRM model is provided below.

Health indices to determine asset condition

The first stage in the CBRM process is to derive a numeric representation of the condition of each asset in the form of a HI. Essentially, the HI of an asset is a means of combining information that relates to its age, environment, duty, and specific condition and performance information (such as original specification, manufacturer) to give a comparable measure of condition for individual assets in terms of proximity to end of life (**EOL**) and probability of failure. The concept is illustrated schematically in figure 3.9.

Figure 3.9 Concept of Health Indices



Source: CitiPower

The HI represents the extent of degradation as follows:

- low values (in the range 0 to 4) represent some observable or detectable deterioration at an early stage. This may be considered as normal ageing, i.e. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the PoF remains very low and the condition and PoF would not be expected to change significantly for some time;
- medium values of HI, in the range 4 to 7, represent significant deterioration, degradation processes starting to move from normal ageing to processes that potentially threaten failure. In this condition, the PoF, although still low, is just starting to rise and the rate of further degradation is increasing; and
- high values of HI (>7) represent serious deterioration, advanced degradation processes now reaching the point that they actually threaten failure. In this condition the PoF is significantly raised and the rate of further degradation will be relatively rapid.

The detail of the HI formulation is different for each asset group, reflecting the different information and the different types of degradation processes. That said, there is an underlying structure for all asset groups as outlined below.

- For a specific asset, an initial age related HI is calculated using knowledge and experience of its performance and expected lifetime, taking account of factors such as original specification, manufacturer, operational experience and operating conditions (duty, proximity to coast, etc).
- Where condition information relating to specific degradation processes can be used to identify potential end of life conditions (e.g. oil test results for transformers), a separate factor is derived for each degradation process, calibrated by linking a defined condition to a specific HI value. This gives rise to a number of multipliers, one for each potential end of life condition. These are then combined to give a 'combined condition factor'.
- Additional information that is indicative of condition but cannot be directly related to specific degradation processes is used to create additional 'factors' that modify the basic age related HI described above. Examples include factors relating to fault/defect history and reliability issues associated with specific equipment types (e.g. different manufacturers).

Calculation of failure rates to assess asset performance

The relationship between the HI and probability of failure for any asset group is determined by matching the HI profile with the recent failure rate. CitiPower uses three condition failure modes according to the following broad definitions:

(i) minor — an incident resulting in no loss of supply; e.g. a stuck mechanism on a trip test;

(ii) disruptive — an incident resulting in loss of supply where the asset can be repaired; and

(iii) catastrophic — the non-repairable failure of an asset resulting in loss of supply and possible damage to adjacent assets.

Non-condition failures, e.g. those caused by external factors such as weather or third party damage can also be included in the CBRM model. However, CitiPower has set the number of non-condition failures in the model to zero such that only condition related failures are considered.

The failure rates in the CBRM have been updated since the AER's 2010 Distribution Determination where the AER criticised the then use of international failure rates within the model on the basis that the failure rates were inconsistent with CitiPower's own historical data.[12]

In 2012, CitiPower reviewed its failure rates and calibrations. Failure rates in each of the three condition failure modes have been calculated by:

- obtaining the average of the number of observed failures over the previous 19 year period for transformers (excluding minor failures) and five year period for circuit breakers using data from the maintenance management system to estimate the number of failures per year; and
- dividing the average number of observed failures per category (as above) by the population of assets.

The longer time period for the disruptive failure rate for transformers is because CitiPower has only experienced four disruptive failures since 1995, and seven events requiring transformer out-of-service other than routine maintenance. The number of failures per year is thus calculated as 11 events over 19 years, or 0.5789 failures per year. Using a five year time period would have removed the observations from the data set.

CitiPower has not experienced catastrophic failure rates for transformers and 66kV circuit breakers. For transformers, CitiPower has used catastrophic failure rate of transformers experienced by Powercor, which has the same asset management processes and a larger fleet. For circuit breakers, CitiPower has thus assumed that, on average, the number of catastrophic failure rates would be around 10 per cent of the number of disruptive failures. This is considered to be a conservative assumption as it is lower than failure rates in published international studies.

12 AER, *Victorian Distribution Determinations – Final Decision*, Appendix P, pp. 613-614.

Table 3.4 CitiPower failure rates used in CBRM

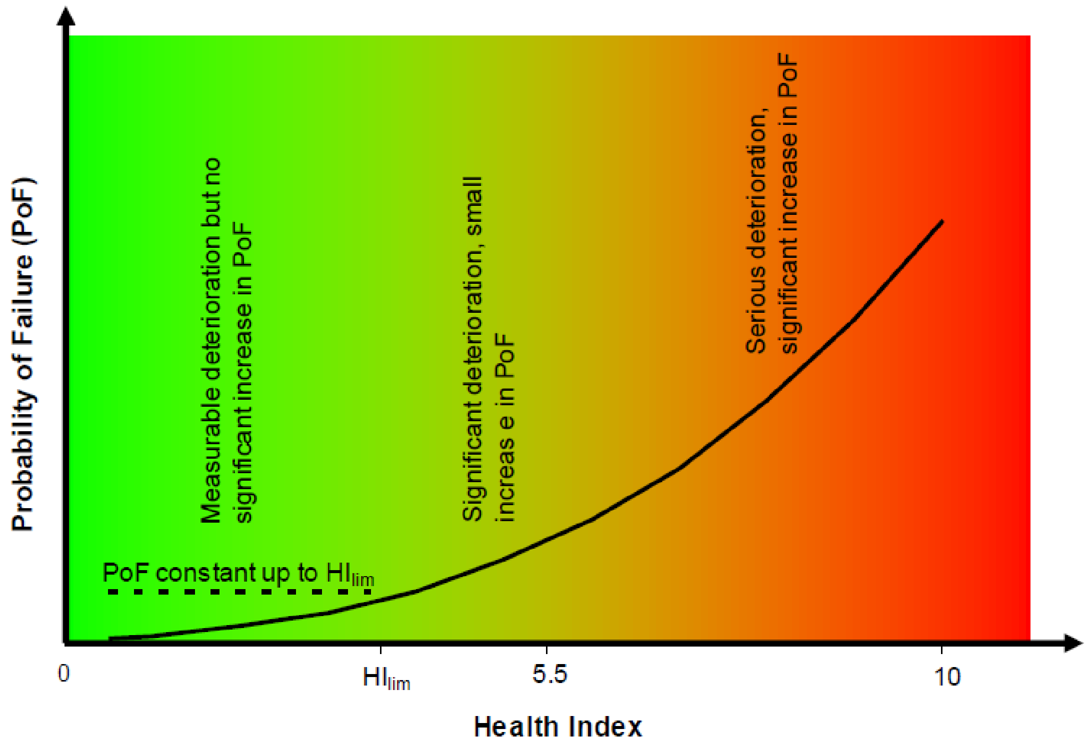
	Transformers		66kV circuit breakers		HV switchgear	
Failure Mode	No. failures per year	Failure rate (no. per asset – year)	No. failures per year	Failure rate (no. per asset – year)	No. failures per year	Failure rate (no. per asset – year)
Minor	62	0.5636	1	0.0133	10	0.0098
Disruptive	0.5789	0.0053	0.0867	0.0012	0.3296	0.0003
Catastrophic	0.074	0.0067	0.0087	0.0001	0.0330	0.0000

Source: CitiPower

The failure rate is calculated from the number of failures per year and divided by the number of assets. There are 110 transformers, 75 66kV circuit breakers and 1005 HV switchgear assets used in the calculation.

The relationship between the HI and condition-related PoF for any asset group is shown schematically (solid line) in the figure below.

Figure 3.10 Relationship between health index and probability of failure



Source: CitiPower

The relationship is not linear. An asset can accommodate significant degradation with very little effect on the risk of failure. Conversely, once the degradation becomes significant or widespread, the risk of failure rapidly increases. The CBRM model uses a third-order polynomial to define the relationship between the HI and the Probability of Failure, which takes into account the HI above the limit value denoted as HI_{lim} in the figure.

This calculation enables CitiPower to estimate the HI that would result in 2020 if it did not undertake intervention works to reduce the risk of failure, such as through replacement or refurbishment works.

Consequence of failure to identify risk

The CBRM assesses four categories of consequences of failure and the units of measurement to quantify the impact, including:

- network performance;
- safety;
- financial (e.g. cost of replacement); and
- environmental impact.

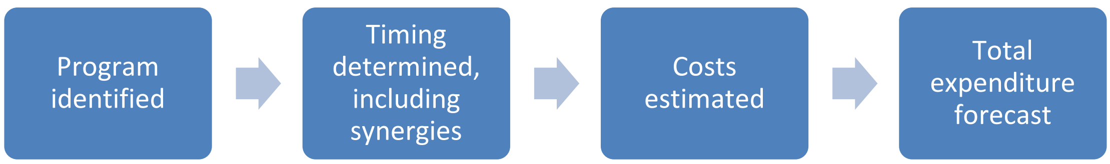
CitiPower quantifies the average consequences using actual data of faults and failures from the last five to ten years, where possible. The environmental consequences are intended to reflect the value that CitiPower places on the various environmental impacts, rather than the cost of clean-up. Generally, the environmental consequence for the failure of a network asset is small, and is unlikely to be the major driver for investment. The possible exceptions to this are oil-filled switchgear and power transformers, where the environmental risk associated with the oil loss makes a significant contribution to the overall risk.

The CBRM output includes a list of the 30 highest ranking assets based on the 'future year delta risk', i.e. the difference between the risk in a future year if the asset is not replaced and the risk that would result if the plant is replaced. CitiPower assesses the various options to deliver the risk reduction for these projects. In addition, CitiPower considers replacement of other assets where there are other drivers or needs for the replacement.

Forecasting costs for transformers and switchgear

The process to forecast assets using the CBRM methodology is set out in figure 3.11.

Figure 3.11 Process for forecasting expenditure for larger assets



Source: CitiPower

The programs are identified through the output of the CBRM process, together with reported maintenance defects of associated equipment, or through the safety-related asset management policies.

The timing of each program is considered in relation to the condition of the asset and the risk associated with the PoF, or in conjunction with other asset projects such as a planned augmentation or customer connection.

Cost estimates have been obtained from a supplier for each of the material replacement projects for transformers and switchgear. For other projects, the cost estimates have been derived from historical project costs for similar projects, where materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

Unit rates

Although CitiPower is required to provide unit rates for the replacement or refurbishment of transformers and switchgear, they have not been used to forecast expenditure given the unique characteristics of each project, such as the location and installation.

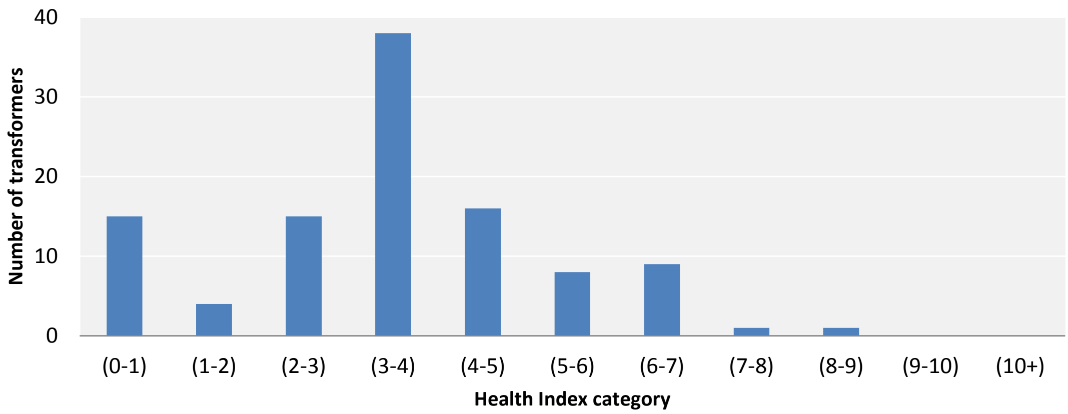
Subject matter experts have verified the reasonableness of the costs based on their knowledge and experience.

Checking the appropriateness of the forecasts using top-down measures

The CBRM process uses the HI of an asset in its current state, and also projects the HI that would result if intervention works were not undertaken, i.e. current and future states.

The HI profile across all assets can be used as a visual tool to understand at a high level the condition of categories of major plant assets, at a point in time. The HI profile of CitiPower's transformers in zone substations at the start of the 2016–2020 regulatory control period is shown in figure 3.12.

Figure 3.12 Forecast health index of transformers at zone substations at the start of 2016



Source: CitiPower

As noted above, the HI is presented in a range from 0 to 10, where 0 is a new asset and 10 represents end of life.

CitiPower focuses on those assets with a HI of seven or above. This represents the stage where planning for replacement is required as the asset is showing signs of end of life and the PoF is increasing. As shown in figure 3.12, at the start of the 2016–2020 regulatory control period, CitiPower will have two zone substations with transformers with HI of seven or above, and they are the Brunswick (**C**) and Russell Place (**RP**) zone substations.

In order to check that the expenditure forecasts are reasonable, sustainable and enable CitiPower to prudently and efficiently manage its ageing and deteriorating large assets using current strategies, maintenance policies and operating practices, the CBRM models are used to generate HI profile predictions for future years.

The profiles are compared using a ‘do nothing’ approach against the forecast replacement (and network reconfiguration) strategies to ensure that, over the forecast period, the HI profile for the total transformer fleet is appropriately managed. A HI profile similar at the end of the forecast period to the current profile infers that:

- no changes to asset management processes are required over the forecast period;
- no backlog of pending replacements at the end of the forecast period; and
- no over-replacement is forecast.

If the HI profile increases over the forecast period, then it may suggest that a step up in expenditure is required.

Other items of plant and equipment

Condition-based monitoring is not possible for all types of plant and equipment. Some plant and equipment rely upon condition-based inspection regimes, similar to poles and wires. For other plant and equipment where condition-based monitoring or assessments cannot be carried out, then other factors may be relied upon to determine the requirement for replacement of the assets. For example:

- earthing cables are replaced following an inspection and/or test of their condition;
- surge arrestors are replaced after they operate, otherwise they are replaced upon age or when there is a change in the plant or configuration of the zone substation;
- indoor combination switches in distribution substations are replaced based on age together with deliverability and risk, given that neither the condition nor performance can readily be measured;
- underground cables are replaced based on performance, given that there is no effective technically viable condition monitoring available on a network level to determine replacement; and
- property is generally replaced based upon condition, such as visible defects in cable ducts, roofs, fences and buildings. Fences may also be replaced following a change in the security requirements for a particular zone substation or other network asset.

Further details of the replacement requirements for these assets are set out in the relevant asset management plans.

Costs for the replacement of these items of plant and equipment have been based on historical or current costs for similar projects, where materials, contract labour and services are sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects. Cost estimates have been obtained from a supplier for the material replacement programs.

3.2.3 Comparison of unit rates

As discussed in the regulatory proposal, benchmarking of costs across distributors can only be appropriate when the following conditions hold:

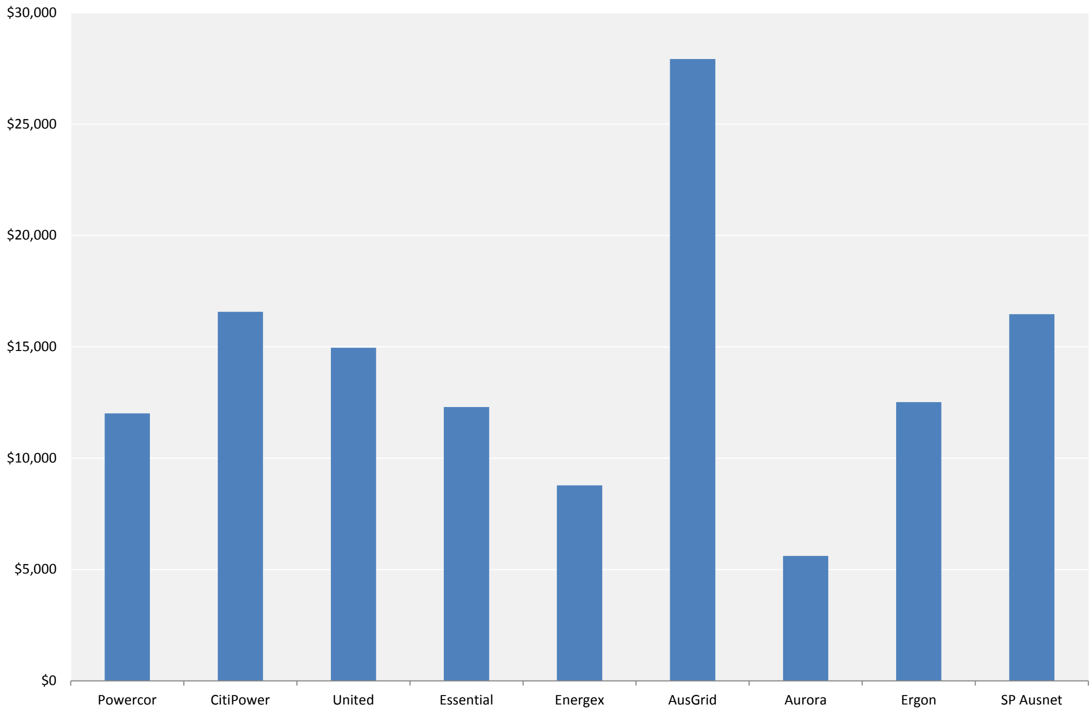
- consistent reporting and interpretations of costs;
- exogenous differences in operating environment are normalised; and
- costs reflect a representative and appropriate sample.

These conditions do not hold for the data for replacements contained in the 2013 Category Analysis RIN, and therefore the AER should be cautious in using the data to inform any of its decisions for the Regulatory Proposal.

Example 1 – replacement of 66kV wooden poles

Take for example the replacement of 22kV to 66kV wooden poles. The unit rate data shown in figure 3.13 represents the average cost over the period from 2009 to 2013, calculated by dividing the total expenditure by the total volumes over the period. Powercor's unit rate appears to be slightly below the average unit cost across all distributors, whereas CitiPower has one of the highest average unit rates.

Figure 3.13 Replacement of 22kV to 66kV wood pole ($/pole)



Source: Category Analysis RIN, CitiPower analysis
Note: distributors with no data have been excluded from the graph

There is a significant difference in the number of wooden poles that the distributors have replaced over the reporting period. The Queensland distributors reported replacing over 1,000 poles each, Powercor replaced 220 poles, whereas CitiPower replaced 26 poles. The low volumes for CitiPower raises concerns that the sample size is not sufficient to be statistically significant.

Further, the operating conditions vary between distributors, as there are exogenous cost differences between undertaking works in an urban environment compared to a rural one. In an urban environment, the physical and temporal access issues include:

- **more complex environment** — CitiPower operates in a complex environment where access to services can be more complex given the existence of tram networks, train tracks, and other services. Works may involve co-ordination with operators of these various services as well as councils and other government bodies;
- **working to tighter timeframes** — given the restrictive window of time in which works can be undertaken as a result of clearways, traffic flow distribution, or timeframes imposed by

VicRoads, local councils or Yarra Trams and as a result, multiple site visits may be required to complete the required works;

- **greater congestion of services** — as the networks of other services such as telecoms, cable TV, NBN, gas, or water may be underground, or in some cases on a pole, such that it may increase the time taken to complete works as it involves working around or connecting and disconnecting these other services;
- **higher traffic management costs** —as traffic management is more complex in an urban environment with greater congestion from motorists, pedestrians and public transport including trains, trams and buses;
- **higher excavation costs** — as it is more frequent and complex in an urban environment and typically entails digging through pavements or roads made of bluestone, pebbles, asphalt, concrete and rock, whereas rural environments often have easier terrain such as grass and pastures. In urban environments, the works may also be have related heritage permission issues, additional traffic management, congestion from other services and potentially hand digging at time;
- **higher reinstatement costs** — following excavation works where CitiPower is required to restore a site to its original condition, both structurally and aesthetically, of a range of surfaces including roads, specialised deep base roads, kerbs and footpaths. Urban roads have a concrete layer under the asphalt, further increasing the costs compared with rural areas where reinstatement may only involve grass or soil; and
- **contamination costs** — where the soil or water may be contaminated at a site, it needs to be tested, excavated, transported and then disposed. In CitiPower and Powercor's experience, contaminated soil and water is more prevalent in urban environments.

The methodology by which costs have been captured is likely to differ between distributors. As noted above, CitiPower is unlikely to undertake a single job to replace a pole, rather it undertakes a package of work which may also involve replacement of the crossarm, transformer, and other assets. As it is more efficient to undertake a package of works, most distributors would also be required to undertake an allocation of costs to the AER reporting categories. The allocation methods are likely to vary between distributors.

Given the uncertainty of the cost allocation methods between distributors, the different operating conditions, and in some cases the sample sizes are not large enough to determine unit costs, it is clear that the data should not be relied upon for benchmarking purposes.

Example 2 – replacement of 66kV circuit breakers and transformers

Comparison of unit rates from the Category Analysis RIN data relating to plant and stations is significantly impeded by difficulties and inconsistencies between distributors. This is apparent from the widespread variability between the unit rates.

For CitiPower, there was a high degree of imprecision in mapping data from its internal reporting systems to the AER's Category Analysis RIN categories. This is because its internal asset management systems were established to capture data relating to the physical assets, but not the associated financial data. CitiPower has separate systems that report financial data.

To populate the Category Analysis RIN, CitiPower has obtained data from its asset register relating to the volume of assets. However, the asset register does not make a direct link between the asset created and the driver for the asset, i.e. whether the asset was a replacement asset or a new asset.

Also, the internal asset reporting systems do not have a direct link to the cost of the creating the asset.

Costs are also not recorded at the asset level, but rather allocated to the internal reporting categories, i.e. function codes. But these codes are not at the level of granularity sought by the AER in the Category Analysis RIN.

Overall, population of the RIN has required shoehorning of the information from CitiPower's IT systems into the AER's categories, which has involved considerable estimation, and despite best efforts, may be subject to error in terms of allocation of costs and volumes to asset groups and sub-categories. CitiPower was not able to map all data from its systems to the AER categories.

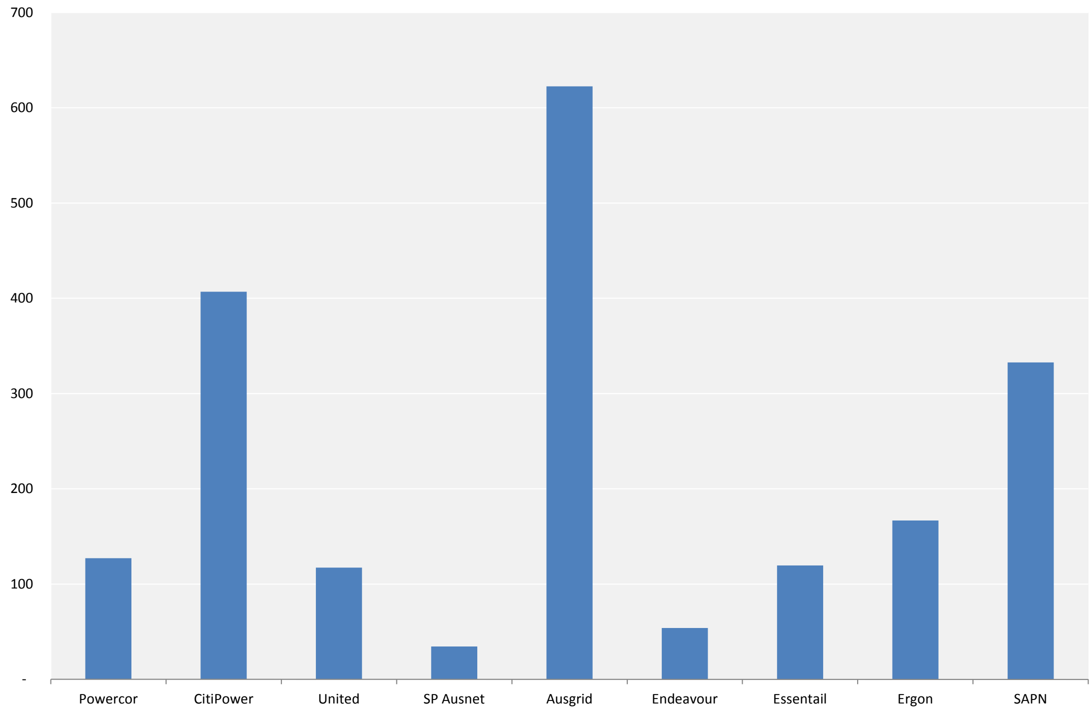
CitiPower considers that its difficulties in providing accurately mapped information were widely shared with other distributors on the basis of:

- its industry knowledge of typical industry practice;
- the basis of preparation documents indicating that various estimation processes were undertaken; and
- several unit rates of other distributors are below realistic material-only costs.

The variability of unit rates for 66kV circuit breakers and 66kV transformers is shown below. It is clear from CitiPower's comments below that the unit rate information from the Category Analysis RIN cannot be relied upon by the AER for benchmarking purposes.

The average unit rate for circuit breakers that operate above 33kV but less than or equal to 66kV is calculated by dividing the total expenditure by the total volumes over the period. The average is shown in figure 3.14.

Figure 3.14 Replacement of 66kV circuit breakers ($000/unit)



Source: Category Analysis RIN, CitiPower analysis

There is a wide variance in the unit rates reported with averages as low as $34,000 per circuit breaker to $622,000 per unit. There is no apparent trend between similar distributors.

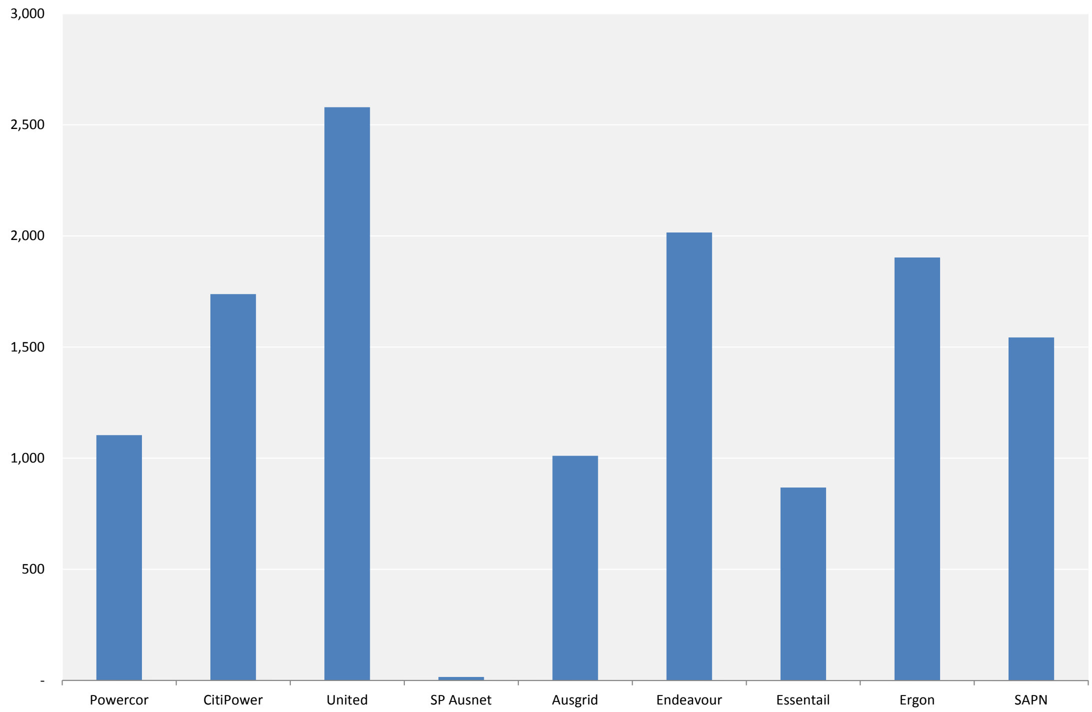
Some variance may be explained by the different types of circuit breakers, which differ by make and model. Currently, CitiPower uses oil breakers, sulphur hexafluoride (SF6) and vacuum breakers in the network. For oil breakers, the oil needs to be filtered every five years, but the life can be extended if spare parts are available. An SF6 circuit breaker has a longer inspection cycle to check the gas levels, however is more costly to replace. Vacuum circuit breakers are relatively new, with lower maintenance costs to check the seal and the pressure and where necessary to replace the vacuum bottle, but are only used for voltages up to 22kV.

The type of circuit breaker installed in the network depends on the operating conditions. Powercor mostly has outdoor circuit breakers, whereas CitiPower has more indoor circuit breakers which use oil. For CitiPower, it is not always possible to individually replace a circuit breaker as it is part of the switchboard, and to replace would generally involve transfer of the entire load away from the zone substation or installation of a temporary switchboard.

Some variance in the unit rates may also be partly explained by the small reported volumes, where there is not a sufficient sample size to provide a robust average cost. It is noted that during the reporting period, CitiPower replaced 11 66kV circuit breakers and Powercor eight 66kV circuit breakers.

A second example is 66kV transformers. The average unit rate for ground outdoor/indoor chamber mounted transformers that operate above 33kV but less than or equal to 66kV, at rating of greater than 15 MVA but less than or equal to 40 MVA, is calculated by dividing the total expenditure by the total volumes over the period, and is shown in figure 3.15.

Figure 3.15 Replacement of 66kV transformers (000s/unit)



Source: Category Analysis RIN, CitiPower analysis
Note: distributors with no data have been excluded from the graph

Again, there is a wide variance in the unit rates reported, with rates from as low as $16,000 per transformer to $2.5 million.

Variance in the unit rates may partly be explained by the low volumes in the reporting period, such that the data is not statistically significant to draw any conclusions. CitiPower replaced one transformer that fitted the criteria. Powercor installed five replacement transformers.

Some variance in the unit rates may also be explained by the fact that the replacement of a transformer at a zone substation can involve the replacement of many other assets, such as fans, heat exchanges or water cooling systems, relays for controllers. The Category Analysis RIN data indicates that some, but not all, distributors included the additional costs associated with replacing a transformer. Others have included physical volumes that may relate to other assets. It is unclear what costs have been included by SP AusNet, given that the costs appear to be lower than the material cost of a transformer before labour and other costs are taken into account.

It appears, however, that for circuit breakers and transformers, the large variance in unit rates is primarily driven by difficulties and inconsistencies between distributors in completing the Category Analysis RIN. This is driven by the fact that the IT systems were not established to capture information in the manner sought by the AER, as the distributors have not required the information in that format to operate their businesses.

3.3 Historic spend

CitiPower has continued to deliver a safe and reliable electricity supply during the 2011–2015 regulatory control period.

As a result of the asset inspection regime where the condition of each asset is reviewed, in the period from 2011 to 2013 CitiPower:

- replaced nearly 400 poles;
- replaced over 30km of underground cables, including 11km in the CBD;
- replaced 20km of overhead cables;
- replaced a transformer, switchboard and 20 associated circuit breakers at the Richmond (**R**) zone substation;
- replaced a transformer at Fitzroy (**F**) zone substation, as well as three 66kV circuit breakers and three HV circuit breakers at other zone substations; and
- replaced control and protection equipment at 16 zone substations.

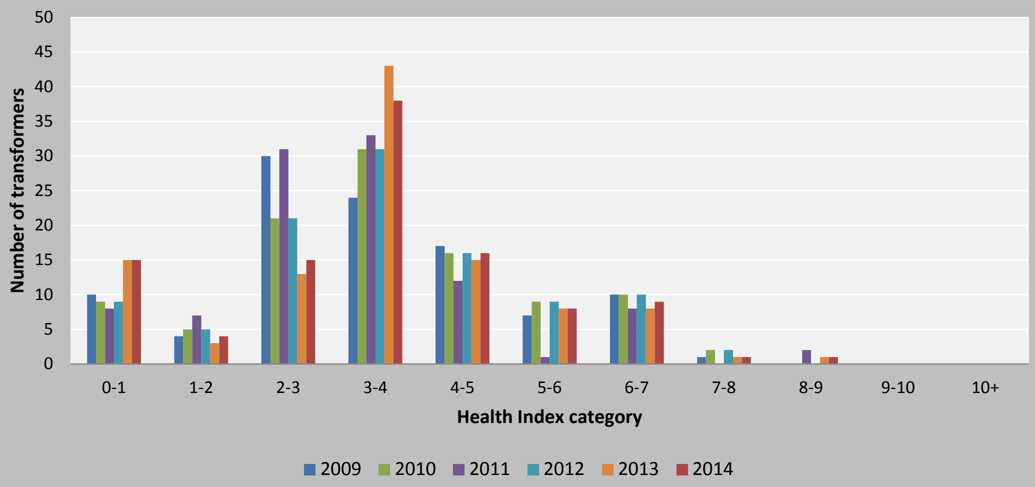
> ‘*Based on the information provided, and performance to date, ESV is satisfied that all the safety programs proposed to the AER and agreed with ESV will be achieved by CitiPower by the end of 2015*’
>
> Source: ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, p. 9.

The above statistics do not include those assets that CitiPower has refurbished or undertaken remedial action to correct defects to maintain and/or prolong the asset life.

Maintaining the health index

CitiPower has maintained the HI profile of its transformers in zone substations over the current regulatory period, as shown in the figure below.

Figure 3.16 Maintaining the Health Index over the current regulatory control period



Source: CitiPower

This demonstrates that CitiPower's expenditure during the 2011–2015 regulatory control period was appropriate, with neither overinvestment nor underinvestment.

CitiPower forecasts that it will underspend its regulatory allowance for replacements in the 2011-2015 regulatory period by 22 per cent. The underspend is driven by two factors:

- knock-on impact of the delayed upgrade to Brunswick Terminal Station (**BTS**) onto replacement projects; and
- efficiencies from network strategies to align major plant replacements and network augmentations.

In terms of the delay to BTS, this impacted the timing of the refurbishment of the Brunswick (**C**) zone substation. The C zone substation is served by 22kV sub-transmission lines from West Melbourne terminal station (**WMTS**). As part of the refurbishment, CitiPower intended to upgrade the zone substation to 66kV, given the long term strategy to replace the ageing 22kV sub-transmission network with the 66kV sub-transmission network. However as WMTS66 is overloaded, CitiPower could only connect the upgraded C zone substation to BTS when it is upgraded to 66kV. The BTS delay has therefore delayed this project.

CitiPower originally intended to replace the assets at Prahran (**PR**) zone substation, which are in in poor health. It was determined that it would be more cost effective to transfer the entire load to the adjacent Balaclava (**BC**) zone substation, by constructing new 11kV feeders and adding a new transformer at BC, thus allowing the ageing assets at PR zone substation to be decommissioned. These works are underway, but are treated as a non-demand related augmentation.

Similarly, the ageing assets at Russell Place (**RP**) zone substation were intended to be replaced. These assets are in poor condition, with two of the transformers having HI scores around a level of seven. However, through the CBD Security and Metro projects, CitiPower determined that it would be more cost effective to transfer the entire load to the new Waratah Place (**WP**) zone substation, thus allowing the ageing assets at RP zone substation to be decommissioned. These works are have been impacted by the delay to BTS, but will predominately be treated as a non-demand related augmentation.

3.4 Forecast spend

CitiPower requires a 74 per cent increase in replacement expenditure compared to its actual spend during the 2011-2015 regulatory control period. The expenditure forecast is driven by:

- completing the refurbishment works intended to take place during the current regulatory period, but which have been delayed as a result of delays to the upgrade of BTS;
- demolition and rebuilding a multi-story zone substation in the CBD area;
- age and condition of large plant and equipment;
- increasing failure rate on poles and crossarms;
- compliance with environmental regulations; and
- age and condition of protection relays and lines.

These factors are discussed in turn below.

Deferred projects from the current regulatory period

As noted previously, the upgrade of BTS was delayed during the current regulatory period.

The timeline below details the steps taken by CitiPower and AusNet Services from May 2008, up to the final decision at Victorian Civil and Administrative Tribunal (**VCAT**) in 2014, to finalise the planning permit requirements for the BTS development.

Figure 3.17 Timeline of Brunswick Terminal Station upgrade delays

2008
- May: Regulatory Test consultation paper published
- August: BTS regulatory test final report

2009
- December: AusNet services lodges planning permit with Moreland Council, proposing use of outdoor air insultation switchgear

2010
- March: AusNet letter of Offer to CitiPower stated completion expected three years from signing
- June: planning application rejected by Moreland City Council

2011
- March: revised regulatory test published, proposing use of indoor gas insulated switchgear
- May: final revised regulatory test report published
- July: revised planning permit lodged with Moreland City Council
- November: revised planning application rejected by Moreland City Council

2012
- February: Minister approves amendment to Moreland Planning Scheme, rezoning site to Special Use Zone and establishing BTS Incorporated Document
- August: AusNet signs contracts with AEMO and CitiPower

2013
- February: Demolition works commence. Community concerns raised about tree removal. Council advises AusNet that removal of existing trees and excavation below one metre requires additional planning approval

2014
- February: AusNet submits revised planning permit application to include existing tree removal and excavations below one metre
- June: Moreland City Council issues notice of decision to grant a planning permit
- July: VCAT revoke planning permit as a result of community concerns
- August: VCAT mediation sessions unsuccessful in resolving issues. VCAT hearing held
- September: VCAT upholds Moreland City Council's planning permit, and AusNet is issued with permit

Source: CitiPower

Those projects must now be undertaken.

The Brunswick (**C**) zone substation redevelopment is required to address the age and condition of its transformers and switchgear. This replacement project is overdue, as it was delayed as a result of delays to the upgrade of BTS.

The switching substation in Waratah Place, referred to as W, is in a deteriorating building. As the station is being upgraded to a new zone substation (**WP**), CitiPower will demolish the existing building and rebuild. This is necessary for the new facility to be capable of safely and securely housing new 66kV switchgear that is part of the CBD Security of Supply project, as well as housing a zone substation. This project was delayed as a result of the delays to the upgrade of BTS, but is now underway.

The WP zone substation will take the entire load from Russell Place (**RP**) zone substation which will be decommissioned. However, defects in the building structure at the RP zone substation need to be rectified to minimise public safety hazards, regardless of the zone substation decommissioning.

Age and condition of large plant

Many of CitiPower's transformers were installed in the 1960s. These assets have high health indices and are in need of replacement. In addition to C zone substation, the transformers in the Richmond (**R**) zone substation and Dock Area (**DA**) zone substation and Russell Place (**RP**) need to be replaced, and the latter will also involve the zone substation being upgraded to be served at 66kV.

The condition of the following assets indicates that the following require replacement:

- switchboard: at Flinders Ramdsen (**FR**) and RP zone substations;
- cooling towers: at FR and Little Bourke St (**JA**) zone substations;
- 66kV circuit breakers: at Armadale (**AR**), Collingwood (**B**), North Richmond (**NR**) and Port Melbourne (**PM**) zone substations; and
- building: Little Queen (**LQ**), W and RP.

It is also noted that the buildings, transformers and switchgear associated with the 22kV sub-transmission network are also in poor condition. Rather than undertake a like-for-like replacement of these assets, CitiPower intends to decommission the network and transfer the load to the 66kV sub-transmission network and zone substations.

The main reason for the timing of a number of these projects is to achieve synergies with the asset refurbishment plans of AusNet Services at their West Melbourne Terminal Station (**WMTS**). When the decommissioning of the 22kV zone substation network supplied from WMTS is carried out, AusNet Services will not be required to invest around $41 million of expenditure to replace their ageing 220/22kV transformers and switchgear at WMTS.[13]

Given CitiPower's strategy to retire the 22kV network, it would be inefficient for AusNet Services to rebuild the 22kV switchyard at WMTS. However, CitiPower needs to offload the Bouverie St/Bouverie Queensberry (**BSBQ**), Spencer St (**J**), Tavistock Place (**TP**) and Laurens Street (**LS**) zone substations served by WMTS22, and upgrade the Dock Area (**DA**) zone substation to 66kV supply from WMTS66, in collaboration with AusNet Services completing the rebuild of WMTS thus providing the most prudent combined transmission and distribution solution.

This project is further discussed in the augmentation chapter.

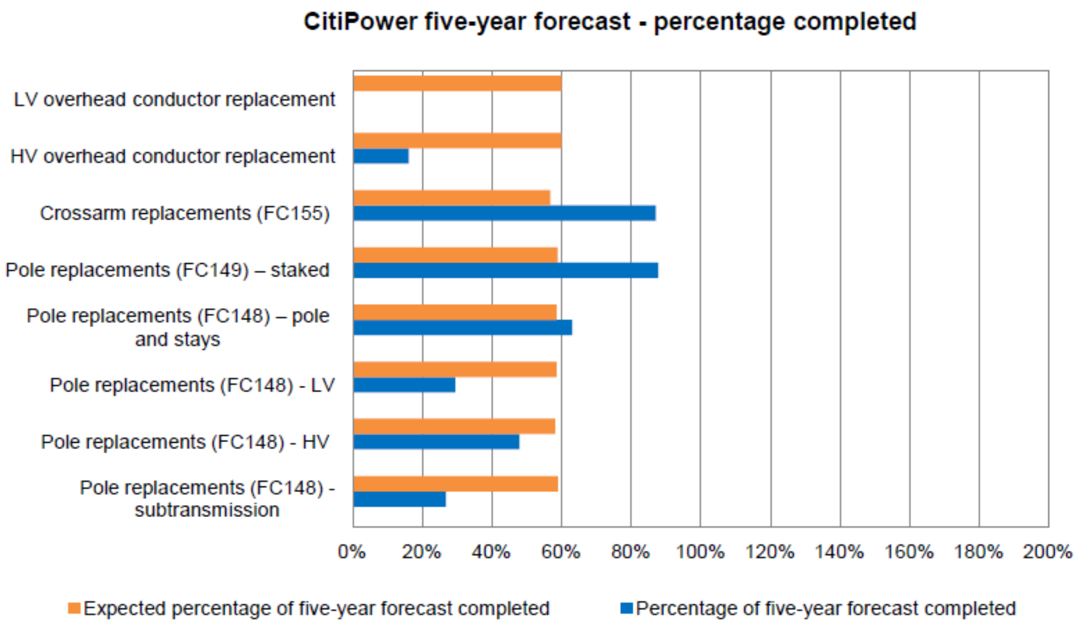
Increasing failure rate on poles and crossarms

In the 2011–2015 regulatory control period, CitiPower replaced significantly more than forecast volumes of poles and crossarms. This was observed by ESV. Figure 3.18 shows the forecast replacements supplied by CitiPower to the AER for the 2010-2015 revenue determination and annualised by the ESV to monitor progress.[14]

[13] AusNet Services, *Letter to CitiPower re: West Melbourne Terminal Station 22kV Asset Replacement Avoided Cost*, 4 March 2015.

[14] ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, pp. 35-37.

Figure 3.18 ESV view of CitiPower five-year forecast – percentage completed



Source: ESV, *Safety Performance Report on Victorian Electricity Networks 2013,* June 2014, p. 35.

However, CitiPower still experienced an increase in the failure rates on poles and crossarms during that time. This indicates that the increasing replacement rates are necessary to maintain the performance of the assets.

As the ESV noted:[15]

> *Over time, the network operating environment, duty cycle and network events contribute to the ageing of assets. These require maintenance or replacement to reduce the probability and rate of asset failure. The rapid rate of electrification of Victoria during the middle of last century means that* many assets are nearing the end of their initial design life….
>
> *Despite a targeted condition assessment and asset replacement program to reduce breakdowns, the number of asset failures has not reduced for all asset classes, especially crossarms and HV fuses. To reduce the asset failure rate, the industry may need to review its condition assessment techniques and reliability approach to asset replacement…*

Poles and crossarms are maintained using the reliability and safety regime process that has been discussed above. The process involved using the historical defect rate for these assets, combined with the forecast number of poles to be inspected, to estimate the forecast number of defects over the 2016-2020 regulatory control period. A higher number of defects is estimated for the forecast period compared with the 2011-2015 period. This is a driver of the increase replacement capital expenditure required for the 2016–2020 regulatory control period compared to the current period.

Compliance with environmental regulations

Electricity networks can create noise pollution through the operation of network equipment for switching, transforming and delivering energy. Whist most forms of noise pollution are transient in

15 ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, p. 31.

nature (for example the operation of a circuit breaker for a few seconds), of particular concern to the public is any constant loud hum generated by power transformers.

The transformers in the Armadale (**AR**) and Montague (**MG**) zone substations are emitting noises that are exceeding the limits permitted by the State Environment Protection Policy (Control of noise from industry, commerce and Trade) No. N-1, also known as SEPP N-1.

CitiPower intends to remove the two noise generating transformers at AR, and the three noise generating transformers at MG, and replace them with low noise transformers. This will ensure compliance with the relevant noise regulations and standards. It is noted that the works at MG will be carried out after the resolution of the matters relating to the renewal of the lease agreement, which is discussed in appendix G.

Protection relays

CitiPower has an ageing protection relay fleet. Modern protection relays also provide significant system information and self-diagnose faults. CitiPower's older fleet of relays has no relay health monitoring, meaning that faulty relays will only be identified when they fail to operate to clear a fault or during a relay maintenance activity.

To prevent an increased probability of the primary protection failing at the same time as the backup protection, and the associated risk of a safety incident, network damage or a lengthy customer outage, it is necessary to increase the rate at which the older protection relays are replaced.

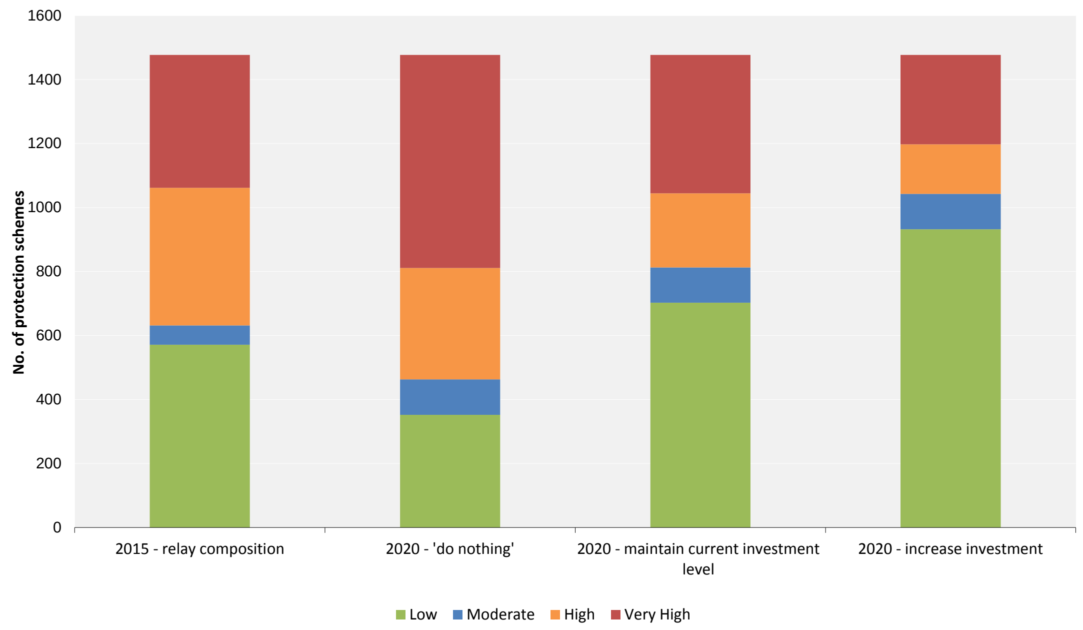
Currently, these assets are managed using the reliability and safety regime process where the risk of the relays failing is based on an assessment of a range of factors including:

- age;
- failure history;
- spares availability;
- serviceability;
- technical skills retention; and
- functional fit to protection policy and standards.

The risk is reflected as a score in the categories of low, moderate, high or very high risk of failure.

By the end of 2015, it is estimated that 57 per cent of CitiPower's assets will be in the high or very high risk categories. Based on the current level of expenditure, this will be 45 per cent by the end of 2020 although the proportion in the very high risk category will remain unchanged. This is shown in figure 3.19.

Figure 3.19 Risk profile of protection relays



Source: CitiPower

CitiPower proposes to both increase the rate of replacement and to target the highest risk relays at the front end of the program to reduce the risk of a protection relay fault impacting the network and safety. For the 2016–2020 regulatory control period, CitiPower intends to reduce the proportion of relays in the high and very high risk categories.

Replacing the ageing relay fleet with modern protection relays will both reduce the safety risks associated with protection relay faults and provide operational benefits such as real time information to help manage the network, self-diagnosis of protection relay faults, fault event data capture for post event fault analysis, better ability to cater for embedded generation and the ability to remotely change relay settings and protection sequences when carrying out modifications to the network.

Checking the reasonableness of the forecasts

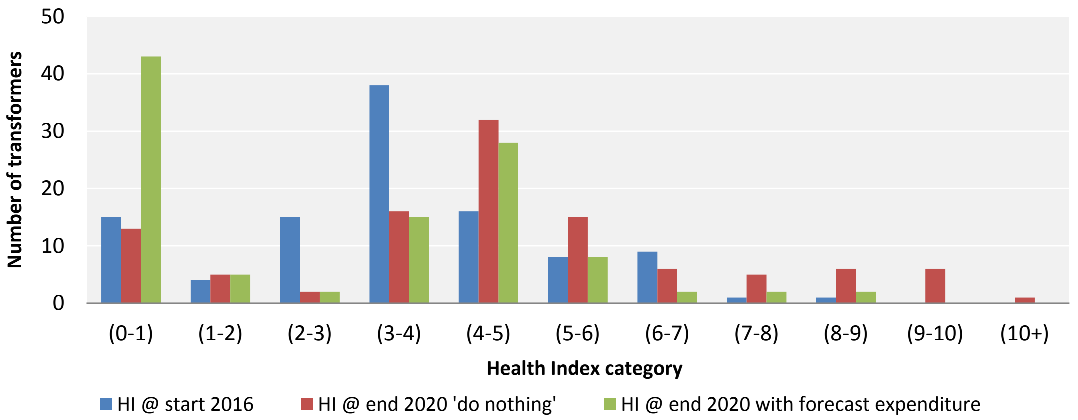
As noted above, CitiPower is able to undertake a top-down check that its expenditure forecasts for transformers and switchgear are reasonable, sustainable and will enable the prudent and efficient management of its ageing and deteriorating large assets using current strategies, maintenance policies and operating practices by using the HI profile predictions for future years.

CitiPower has created the HI profile at the start of the 2016–2020 regulatory control period and compared that to:

- the profile that would occur in the 'do nothing' scenario over the 2016–2020 regulatory control period; and
- the profile that would occur if it undertakes the investments set out in this regulatory proposal.

Using transformers in zone substations as an example, figure 3.20 shows that CitiPower's forecast expenditure is reasonable as it is able to appropriately maintain the number of transformers with a HI of seven or above, as well as maintain the overall HI profile. If CitiPower did not undertake any investment over the 2016–2020 regulatory control period, then the number of zone substations with transformers with a HI of seven or above would rise from two to seven.

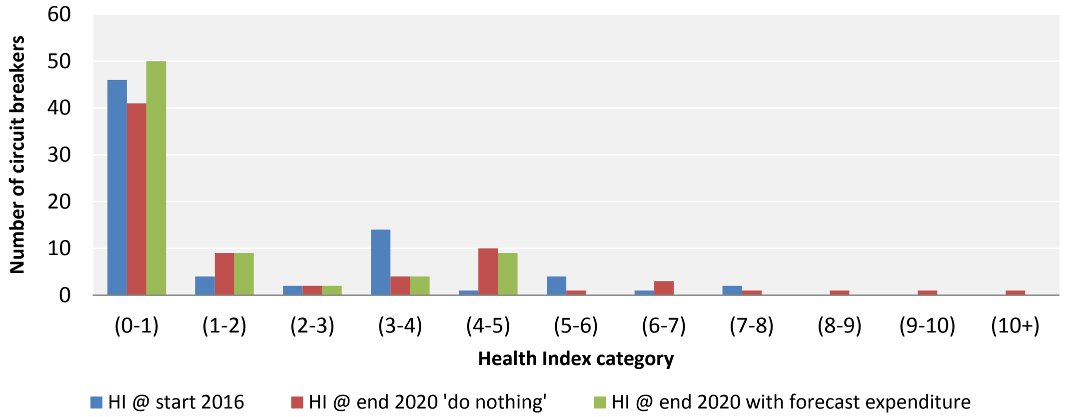
Figure 3.20 Transformers health index in 2020 with and without investment



Source: CitiPower

CitiPower has undertaken similar analysis for its 66kV circuit breakers, as shown in figure 3.21. The figure clearly demonstrates that without remedial action, four circuit breakers will have high values of the HI with an associated high probability of failure.

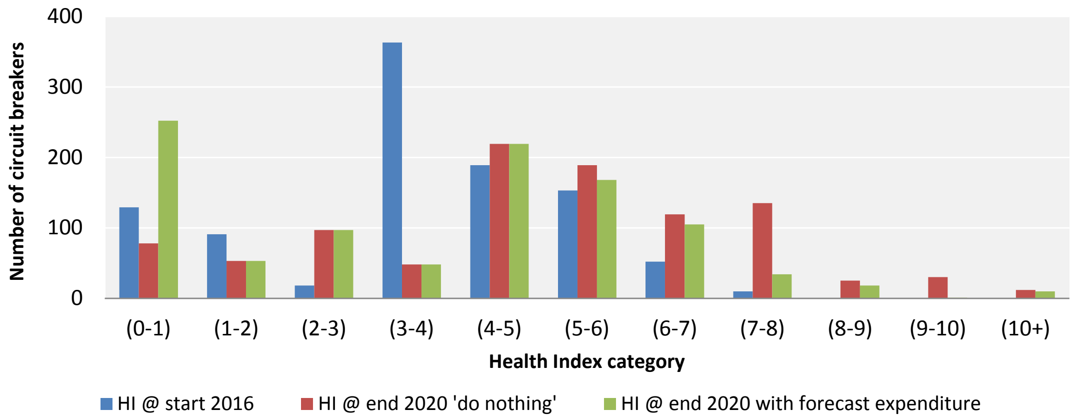
Figure 3.21 Health index of 66 kV circuit breakers



Source: CitiPower

Finally, CitiPower has undertaken analysis of the health indices of its switchgear, comprising 22kV, 11kV and 6.6kV circuit breakers, per figure 3.22. It can be seen that a large number of circuit breakers will have a high value HI unless the investments outlined in this regulatory proposal are undertaken in the 2016-2020 regulatory control period.

Figure 3.22 Health index of switchgear (22kV, 11kV and 6.6kV circuit breakers)



Source: CitiPower

CitiPower's expenditure forecast is targeted at replacing or refurbishing those assets with a HI of seven or greater over the 2016–2020 regulatory control period. The accelerating effort to maintain the HI profile reflects the large proportion of switchgear that is approaching end of life, given that the majority were installed in the 1960s and 1970s.

3.4.1 Programs and projects

Table 3.5 provides an overview of the large programs of work over $5 million that CitiPower intends to undertake during the 2016-2020 regulatory control period.

Table 3.5 Network service material projects

Project name	Driver	Direct cost ($2015, million)	Material project #
W: building replacement (LQ, W & RP)	Condition	6.80	REPL 01
Low voltage paper based cable replacement	Condition	10.3	REPL 02
Redevelopment of C zone substation	Condition	14.2	REPL 03
Replacement of indoor combo switches	Safety	6.6	REPL 04
Protection relays replacement	Condition	20.4	REPL 05
Environmental noise program (AR)	Environmental compliance	5.6	REPL 06
Environmental noise program (MG)		9.2	REPL 07
Replacement of underground pits	Safety	5.3	REPL 08
Environmental bunding program	Safety	4.4	REPL 09

Source: CitiPower
Note: direct costs excluding real escalation

Replacement and upgrading of the switching substation in Waratah Place, referred to as W, to a new one substation (**WP**) was discussed above. Similarly, the replacement of protection relays and environmental noise programs were discussed above.

Low voltage paper-insulated lead sheath cable replacement

CitiPower manages 1,400km of low voltage mains and service cables, including single phase and multi-phase cables and circuits. It includes low voltage underground cables which are made of paper-insulated lead sheath and at or near end of life. Failures of this type of cable are typically due to moisture ingress into the insulating papers as a result of cracks in the ageing lead sheath.

Repairs are only reliable if joints can be made to ends of cable that are not affected by moisture. The age of the cable network is such that faults and failures are common and becoming more difficult to repair. In some cases the cables have been bypassed by other cables or temporary overhead conductors.

CitiPower intends to replace the entire fleet of paper insulated lead sheath low voltage cables over the 2016–2020 regulatory control period with modern cable types, to maintain safe and reliable supply of electricity to customers.

Redevelopment of C zone station

The Brunswick (**C**) zone substation serves the Brunswick area and has ageing assets and associated network equipment that are in poor condition and require replacement. It consists of four 22kV/6.6kV transformers, although the fourth transformer is out of service as a spare transformer, and is supplied via underground 22kV sub-transmission cables from Brunswick Terminal Station.

The transformers at C have high health indices are require replacement, as shown in table 3.6. The switchgear at C also has high health indices.

Table 3.6 Health Indices of Brunswick (C) zone substation transformers

Transformer	Health index @ start 2016	Health index @ end 2020 (no intervention)
C No 1 22/6.6kV transformer	6.60	8.39
C No 2 22/6.6kV transformer	8.27	10.78
C No 3 22/6.6kV transformer	6.60	8.39
C No 4 22/6.6kV transformer	6.16	7.98

Source: CitiPower

Based on rigorous asset condition based assessment, a number of indicators have confirmed that the C zone substation and its assets are at end of life, specifically:

- the existing four 22kV/6.6kV transformers are aged and in poor condition;
- the existing transformers are fixed tap therefore regulation of customers voltage is not always possible;
- the existing 6.6kV switchboard is aged and in poor condition;

- the substation is supplied by aged and poor condition 22kV sub-transmission cables from BTS, which were installed approx. 1940; and
- the existing transformers are separately supplied by cable and there are no 22kV bus ties, limiting flexibility and supply security.

This represents significant risk of failure and in terms of this type of circuit breaker and this type of switchboard, a catastrophic failure of one circuit breaker may cause irreparable damage to the switchboard bus and expose personnel to unacceptable health and safety risk.

CitiPower intended to upgrade C zone substation during the current regulation control period, however this was delayed as a result of delays to the upgrade of BTS.

CitiPower now intends to redevelop the C zone substation, and at the same time upgrade the supply to 66kV. This will allow connection to the 66kV sub-transmission line from West Melbourne terminal station to Northcote (**NC**) zone substation which runs adjacent to the southern boundary of the C zone substation property.

Replacement of indoor combo systems

In some CitiPower areas, indoor substations use wall-mounted air insulated single phase arc chute switches and covered conductor cabling to provide ring switching. In these arrangements the transformer switches control wall mounted HV powder filled fuses that in turn supply the transformer(s). The transformer switch fuse units of this type are generally known as combo units. Indoor wall mounted arc chute switches have phase barriers of compressed fibre board. Some of these switches may still contain asbestos sheet phase barriers.

These units require operation via HV operations stick. Such method of operation within an indoor substation places the 'operator' at additional risk. As the units are fully exposed they are also vulnerable to shorting out by vermin as has been experienced in a number of cases throughout the network.

The age of the units combined with the fact that they are manual type switches (i.e. operator dependent) also supports replacement. Many, if not all units, are mounted on asbestos material which limits the level of maintenance that can be achieved. Hence the replacement of such units also allows for removal of associated asbestos material.

CitiPower intends to progressively replace these switches over time with standard ring main units (**RMU**). The prudent rate of replacement has been determined to be approximately ten switches per annum over an extended period of time.

Replacement of underground pits

CitiPower owns and manages approximately 1,000 pits in the CBD. These pits form part of the conduit and pit system throughout the CBD that facilitates the installation of CitiPower's HV, LV and communications cables. Pits are used to access the conduits and cables without the need to excavate roads and footpaths in the CBD. Installation of new and replacement cables is generally possible by opening adjacent pits and pulling cables though the conduits that connect between the pits. Cable jointing is also carried out in these pits.

Of the total population of pits, 474 pits are in roadways or footpaths in the Melbourne CBD. In the past few years a number of pits accessed for planned cable works or fault rectification have been identified as unsafe due to the extent of corrosion of the supporting steel structures and spalling of concrete. Corrosion will occur in most pits due to the presence of moisture that seeps in though the walls and openings as well as via the banks of conduits. Loss of strength of the supporting steel and reinforcing within the concrete due to corrosion results in the hazard of roof or opening (covers) failure. Such failures could result in collapse of the pit roof or collapse of the pit covers at the surface opening. The consequence of a roof or cover opening could be catastrophic in terms of serious injury to the public and CitiPower personnel.

CitiPower intends to remediate the highest risk pits founds to be defective through the inspection program over the next five years.

Bunding program

Electricity networks may potentially create soil contamination and groundwater pollution through the operation of network equipment containing significant volumes of oil. Such equipment is used for switching, transforming and delivering energy. One of the largest oil filled network elements that present a risk to the environment of oil leakage are power transformers in zone substations which may leak material volumes of oil as their condition deteriorates.

Victorian contamination and wastewater protection is regulated by the Environment Protection Authority under the State Environment Protection Policy (**SEPP**). The SEPP for contamination stipulates that the occupier of any site must ensure that the land is managed to prevent contamination and must apply best practice in this regard. The SEPP that governs groundwater contamination states that all practicable measures must be taken to prevent pollution of ground water and stormwater.

One of the recognised most effective treatments for transformer oil leak risk is the containment and treatment of leaks via bund walls. A bund wall is a complete enclosure built around the transformer that contains any oil spills within the wall boundary until such time that it can be treated or removed. Coupled to this is the treatment of water at the site to separate oil from water before it enters the storm water or ground water systems.

CitiPower has an ongoing program to install bunding and drainage at zone substations, where insufficient bunding and drainage exists, so as to meet regulatory requirements and the Australia Standard 1940.

For the 2016–2020 regulatory control period, CitiPower has identified the Fishermans Bend (**FB**), Collingwood (**B**), Riversdale (**RD**), Southbank (**SO**) and Collingwood (**CW**) zone substations as having the highest environmental risk where it will undertake bunding and drainage programs to ensure compliance with environmental regulations and standards.

3.5 AER repex model

In the Forecast Assessment Expenditure Guidelines, the AER indicated that it will use the 'repex model' as part of its assessment of the proposed replacement capital expenditure. The repex model is a high-level probability based model that forecasts replacement for various asset categories based on their condition (using age as a proxy) and unit costs.[16] This model has previously been applied to CitiPower by the AER in the 2011-2015 regulatory determination.

The AER recognises that there are a range of factors that can influence the replacement life for an asset, including the:

- operational history;
- environmental condition (e.g. damp or dry, or coastal or inland); and

[16] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, p. 185.

- quality of its design and installation (including early-life failures of assets).[17]

The AER considers that the remaining life of an asset is a function of a number of factors, most notably its condition, and therefore a population of similar assets will have a range of lives.

Given the complexity of predicting the replacement of individual assets, the AER considers the purpose of the repex model is to simplify the analysis but still maintain some accuracy at the aggregate level.[18]

The repex model simplistically predicts the volume of replacement based on the age of system assets on a distributor's network. To do this, the model requires information for each asset category on the age profile, replacement lives including the mean replacement life and standard deviation, and unit costs. The 'base case' model is then calibrated to determine the asset lives and unit costs that represent the historical replacement level of the distributor over the preceding five year period. The calibrated model is considered the 'benchmark model' in circumstances where the AER is satisfied that the historical replacement levels reasonably reflect prudent and efficient expenditure.

As the repex model simplifies a complex range of factors to forecast the replacement of assets, it has inherent limitations including:

- the life of assets replaced in the past is assumed to be the same as for assets replacement in the future, such that the repex projections are backward looking and may differ significantly from a truly optimal forward looking replacement program;
- assumption that recent past replacement expenditure reflects implementation of an optimal replacement strategy;
- the number of units replaced in the past is directly proportional to historical expenditure;
- use of asset age as a proxy for the many factors that drive individual asset replacement, where other drivers such as safety or environmental standards may be the primary driver for particular asset categories;
- assumption of a normal distribution profile around the mean for the replacement life of each asset category, where there is likely to be a high degree of variability around the 'mean' age that limits the accuracy of its use in predicting volumes for replacement; and
- sample sizes may be too small for some asset sub-categories to be statistically significant, and thus may lead to inaccurate results.

In light of the limitations of the model, the AER suggests that it will only use the repex model to cross-check the forecasts of a distributor where those forecasts appear to be deficient. The AER notes:[19]

> *It should be recognised that the mangers of capital assets will frequently rely on alternative techniques to determine their asset replacement strategies. A particular approach may include critical impact, condition based or risk based techniques or a mix of these or other techniques. The repex model approach does not replace those techniques. They are all valid approaches and may give superior estimates of replacement need in particular circumstances. However, if the explanations of proposed replacement volume or cost are found on closer examination to*

[17] AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013, p. 9.

[18] AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013, p. 9.

[19] AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013, p. 10.

> *be deficient, then the repex model will provide an alternative point of reference for consideration.*

CitiPower has therefore provided below a cross-check of its own forecasts with the repex model to demonstrate that its replacement expenditure forecasts are robust.

3.5.1 Output of the repex model

As noted above, the AER's repex model simplistically predicts the volume of replacement based on the age of system assets on a distributor's network.

The AER's model indicates that the largest category of replacement costs will be for underground cables, followed closely by transformers. CitiPower's own forecasts have transformers and switchgear as the largest categories of expenditure.

The repex model uses history to 'calibrate' the average replacement lives of assets across the business. This leads to results that are outside the normal industry expectations. For example, in reviewing the model in 2010, Parsons Brinckerhoff found that the asset lives determined by the repex model were not reasonable, noting:[20]

> *PB considered the case of CP's underground cables which comprise 43% of the network replacement value. From our analysis we noted that the calibrated average life of 87 years for CP is 17 years longer than that applied for Jemena and United at 60 years, and 44 to 45 years longer than that applied for SP AusNet and Powercor at 42 and 43 years respectively. Given the average life of 87 years, and Nuttall's standard deviation approximation, this suggests an expectation that 20% of the cable population will remain in service for over 95 years, with 8% remaining in service for over 100 years. PB is not aware of any Australian distributor that would expect any cables to remain in service for over 100 years. Therefore we consider that the calibrated life input to the model does not appear to be aligned with industry expectations.*
>
> *Similarly, PB notes that in the case of CP's Secondary Systems, an average life extension of 6 years has been applied over the PAL proposed life of 49 years. In our opinion this ignores the fact that equipment of this type are typically replaced due to obsolescence, withdrawal of vendor support, or the unavailability of spares, and PB considers that the likelihood of achieving an average service life extension of this magnitude is extremely low without accepting the considerable amount of additional risk, or incurring mitigating expenditure associated with operating obsolete equipment.*

As a result, the repex model may understate the level of capital expenditure that CitiPower will require to replace some categories of assets.

A detailed description on the data and methodology that CitiPower has used in populating the repex model is provided in the attached report by Jacobs, *CitiPower repex modelling review*.[21] This report includes an independent review and validation of the population and running of the model, which was compared against the AER's *Replacement expenditure model handbook*.

3.5.2 Reconciliation

The repex model forecasts a lower level of overall expenditure for replacement related works compared to CitiPower's forecasts. For the elements of replacement expenditure where the cost

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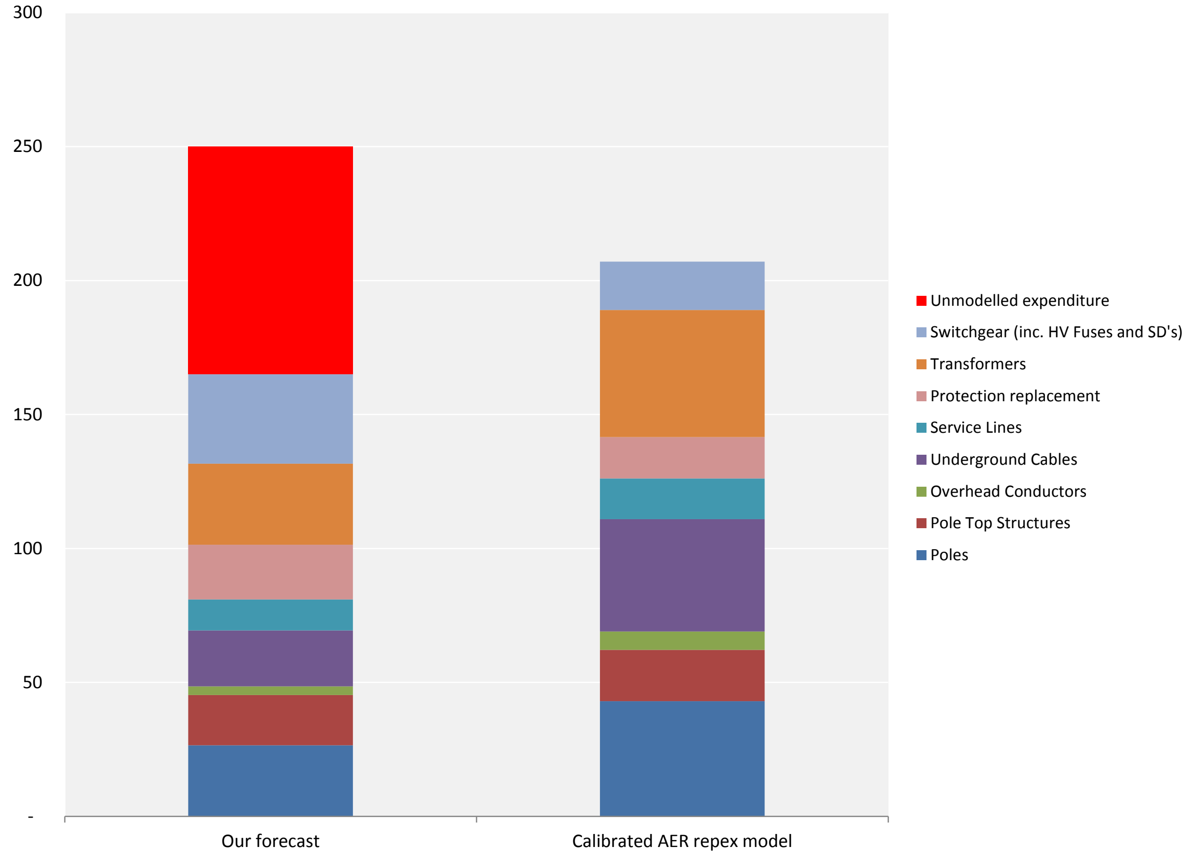
20 Parsons Brinckerhoff, *Repex model review CitiPower – Powercor*, July 2010, p. v.

21 Jacobs, *CitiPower repex modelling review*, 17 April 2015.

drivers are covered by the repex model for standard control services, CitiPower's forecasts are 20 per cent lower than the forecasts from the repex model. This is shown in figure 3.23.

Figure 3.23 Comparison of CitiPower's forecast to repex model forecast output ($million, 2015)



Source: CitiPower
Note: direct costs excluding real escalation

Categories where the forecast is higher than the repex

CitiPower's expenditure forecast proposes more capital expenditure than the AER's repex model in the categories of switchgear and protection.

CitiPower notes that:

- switchgear — the CBRM model is used to determine when the replacement or refurbishment of switchgear in a zone substation is required. The CBRM considers that condition of the asset together with environmental factors, rather than solely relying upon the age of the asset; and
- protection — a large number of protection relays have been assessed to be at a high or very high risk of failing, and therefore it has a program to increase the replacement rate of these assets.

Unmodelled replacement expenditure

The repex model is not expected to reflect all of the replacement costs for assets incurred by a distributor. The AER 'expects that the chosen sub-categories should represent between 70 to 80 per cent by value of replacement expenditure'.[22] CitiPower calculates that the drivers of the repex model covers around 66 per cent of its replacement expenditure.

The repex model does not cover those assets that are either not replaced by age, or are not defined by a detailed asset age profile required by the repex model, including:

- property, buildings and associated facilities,
- asset refurbishments and component replacements; and
- environmental expenditure.

AER's repex model does not include costs such as property refurbishments, such as replacing a roof on a zone substation, replacement of fences, and general maintenance activities. These costs are essential to maintaining the distribution network, but are not associated with an age profile and thus are excluded from the repex model. For example, it does not include building civil replacement costs associated with the Brunswick (**C**), Russell Place (**RP**) zone substations or the Waratah Place switching station (**W**), nor does it cover costs associated with fire systems, lifts or cooling systems.

Costs associated with the program to remediate the highest risk underground pits in the roadways or footpaths in the Melbourne CBD are also excluded from the repex model. Some pits opened for cable works have been found to be in a deteriorated and dangerous condition. The significant hazard is the sudden collapse of the pit covers or lids under the weight of traffic or pedestrians.

The repex model also does not capture expenditure associated with management of environmental matters, for example, the reduction of noise pollution in excess of Environmental Protection Authority standards, or the replacement of line coverings preventing bird interference.

[22] AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013, p. 13.

4 Augmentation

> To ensure that CitiPower continues to support the growth and development of its communities, investment in high growth areas needs to be targeted to meet expected demand. That is, the capacity of the network needs to be increased where it is forecast that customers will demand more electricity than the network capacity in that location, particularly on extremely hot days when air-conditioners drive up demand.
>
> CitiPower's proposed capital expenditure will also allow it to undertake augmentation to maintain the security, reliability and quality of supply of the network.

This section discusses CitiPower's historical and forecast augmentation expenditure as well as its approach to calculating the expenditure.

4.1 Overview

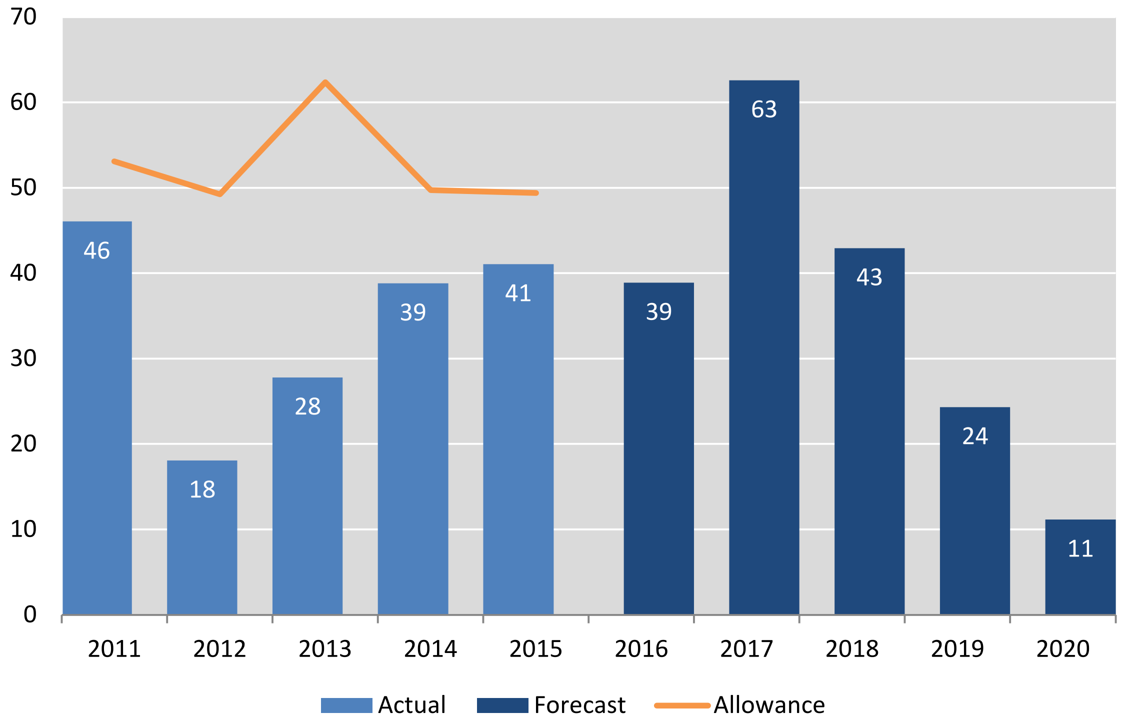
Augmentation capital expenditure relates to capital expenditure required to achieve the capital expenditure objective to meet or manage the expected demand for standard control services over the 2016-2020 regulatory control period.

Augmentation capital expenditure comprises:

- demand driven expenditure to upgrade the capacity of the existing distribution network, in response to spatial demand growth;
- non-demand expenditure required to address the security of supply of the network; and
- non-demand expenditure required to address the maintenance of reliability and quality of supply of the network.

An overview of the historical and forecast expenditure is shown in figure 4.1.

Figure 4.1 Augmentation direct capital expenditure ($ million, 2015)



Source: CitiPower

The impact of the delays to the upgrade of Brunswick Terminal Station (**BTS**) on the CBD Security Upgrade and Metro projects can be seen in the above profile, as expenditure has been deferred.

CitiPower's customers support the increase in capacity of its network to meet load growth. In response to the Directions and Priorities consultation, the City of Melbourne noted that:[23]

> *Yes, we are satisfied that the investments are targeted and focused on building infrastructure where it is needed most.*

However, the majority of CitiPower's augmentation expenditure is not to address localised growth in demand. Rather, the key programs of work which will drive the increase in expenditure is related to:

- non-demand related augmentation works related to replacing capacity due to the decommissioning of the 22kV sub-transmission network; and
- security of supply related works, including the CBD Security and Metro upgrades.

4.2 Background information

This section describes the methodology for forecasting augmentation capital expenditure.

4.2.1 Key drivers for expenditure

Augmentation expenditure is generally driven by an increase in peak demand, which may result in a shortage of capacity for the network assets, as determined by the planning policies of CitiPower.

[23] City of Melbourne, *Directions and Priorities Consultation Paper response*, 17 October 2014, p. 7. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/13.City-of-Melbourne-17-October-2014.pdf.

However, augmentation expenditure may also be driven by non-demand factors such as delivering security of supply to a different planning standard if the requirements of a Regulatory Test or Regulatory Investment Test for Distribution (**RIT–D**) need to be met; or ensuring quality of supply to maintain voltage or fault levels within the thresholds required by the regulations or equipment design.

At times, augmentation expenditure may be driven by both demand and non-demand factors. For example, the forecast increase in demand on a sub-transmission line may also result in voltage levels being forecast to exceed the allowable threshold. In such cases, the expenditure will be categorised as demand driven as that is the primary driver of the augmentation.

Similarly, if a single customer is connecting a new or additional load, then the augmentation required to supply that customer will be categorised as connection and customer driven works capital expenditure. The driver in this case is the connection to the single customer.

4.2.2 Network planning standards

In general there are two different approaches to network planning.

- **Deterministic planning standards** — this approach involves prescribing the amount of redundancy that must be built into the network to avoid supply outages. The level of redundancy is prescribed in 'N-x' terms, where 'x' the number of network elements that could fail without electricity supply being lost. For example: N-1 means electricity supply will not be disrupted if one element of the network fails.

  A strict use of this approach may lead to inefficient network investment as resilience is built into the network irrespective of the cost of the likely interruption to the network customers, or use of alternative options.

- **Probabilistic planning approach** — the deterministic N-X criterion is relaxed under this approach, and simulation studies are undertaken to assess the amount of energy that would not be supplied if an element of the network is out of service. As such, the consideration of energy not served may lead to the deferral of projects that would otherwise be undertaken using a deterministic approach. This is because:
  - under a probabilistic approach, there are conditions under which all the load cannot be supplied with a network element out of service (hence the N-1 criterion is not met); however
  - the actual load at risk may be very small when considering the probability of a forced outage of a particular element of the sub-transmission network.

CitiPower adopts a probabilistic approach to planning its augmentations. The probabilistic planning approach involves estimating the probability of an outage occurring within the peak loading season, and weighting the costs of such an occurrence by its probability to assess:

- the expected cost that will be incurred if no action is taken to address an emerging constraint; and therefore
- whether it is economic to augment the network capacity to reduce expected supply interruptions.

The quantity and value of energy at risk (which is discussed in section 4.2.3) is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint. Probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints; and
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, recognising that very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under conditions of extreme loading. The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower unserved energy.

This approach provides a reasonable estimate of the expected net present value to consumers of network augmentation for planning purposes. However, implicit in its use is acceptance of the risk that there may be circumstances (such as the loss of a transformer at a zone substation during a period of high demand) when the available network capacity will be insufficient to meet actual demand and significant load shedding could be required. The extent to which investment should be committed to mitigate that risk is ultimately a matter of judgment, having regard to:

- the results of studies of possible outcomes, and the inherent uncertainty of those outcomes;
- the potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of peak demand, and catastrophic equipment failure leading to extended periods of plant non-availability; and
- the availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk.

4.2.3 Forecasting methodology

CitiPower has undertaken a bottom-up build of its augmentation expenditure forecasts, factoring in any synergies between replacement and augmentation projects. The output of this process is then verified by assessing the reasonableness of the outcomes against the forecast key network risks metrics labelled Load Indices and Health Indices.

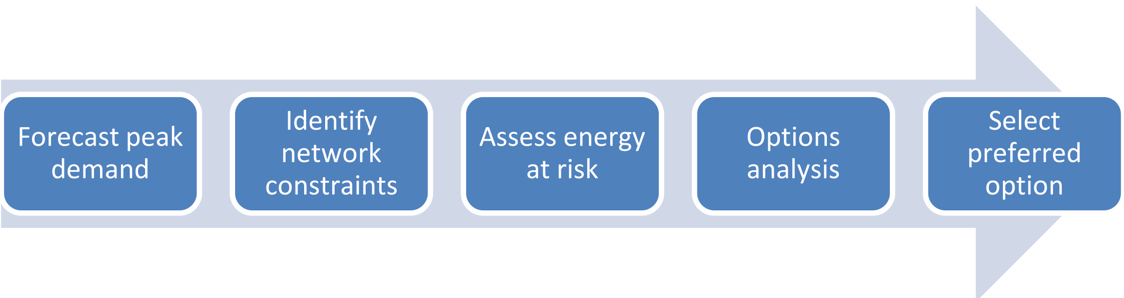
The methodology for forecasting the expenditure depends on the driver for the augmentation, namely if it is demand or non-demand driven.

Demand driven forecasts

For augmentations that are driven by increasing demand on the distribution network, CitiPower has undertaken the steps outlined below. This process is consistent with the methodology that is set out in the Distribution Annual Planning Review (**DAPR**) published each year by CitiPower.

The steps undertaken in forecasting augmentation capital expenditure is shown in figure 4.2. These are further discussed below.

Figure 4.2 Process to forecast augmentation capital expenditure



Source: CitiPower

It is noted that constraints at the transmission connection points can also lead to requirements to augment the distribution network. The transmission connection assets are located within terminal stations, which are owned, operated, and maintained by the transmission asset owner, generally AusNet Services. The methodology for identifying those constraints is set out in the Transmission Connection Planning Report (**TCPR**) which is prepared and published annually by the five Victorian distributors.

Where a transmission connection asset constraint is identified, a Regulatory Test for Transmission (**RIT-T**) is undertaken to determine the preferred option to address that constraint, which is the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market. Such a test would generally be conducted jointly with AEMO, which has responsibility for planning the Victorian shared transmission network.

Step 1: Forecast peak demand

The detailed process for forecasting peak demand for a network asset is set out in Appendix C. The forecasting and planning processes take into account a number of factors including statistical temperature forecasts, new connections, usage patterns and economic factors to estimate the required capacity of the network. At a high level, the forecasting process consists of:

- top–down independent econometric forecasts at the terminal station using the regional models prepared by the Centre for International Economics (**CIE**), which is consistent with the best practice methodology described by ACIL Allen in their 2013 report the Australian Energy Market Operator (**AEMO**) for connection point forecasting;[24]
- bottom-up forecasts for demand at high voltage (**HV**) feeder and each zone substation, taking into account information about customer connections and embedded generators, which has been reconciled to the top-down CIE forecasts; and
- the reconciled zone-substation forecasts have been used to model forecasts of maximum demand on each sub-transmission line using the powerflow analysis tool called Power System Simulator for Engineering (**PSS/E**).

As peak demand in CitiPower is very temperature dependent, the actual peak demand values are normalised in accordance with the relevant temperatures experienced across any given summer loading period. The correction enables the underlying year-by-year peak demand growth to be estimated, which is used in making future forecasts and investment decisions.

The temperature correction is used to determine the '50th percentile maximum demand'. The 50th percentile demand represents the peak demand on the basis of a normal season (summer and winter). For summer, it relates to a maximum average temperature that will be exceeded, on average, once every two years. By definition therefore, actual demand in any given year has a 50 per cent probability of being higher than the 50th percentile demand forecast. The 50th percentile forecast can therefore be considered to be a forecast of the 'most-likely' level of demand, bearing in mind that actual demand will vary depending on temperature, and other variables such as the day of the week. It is often referred to as 50 per cent probability of exceedance (**50% PoE**).

For the purposes of the regulatory proposal, CitiPower has also forecast peak demand at 10 per cent PoE, to prepare contingency plans for maximum demand during periods of very high or extreme temperatures.

[24] ACIL Allen Consulting, *Connection point forecasting – a nationally consistent methodology for forecasting maximum electricity demand*, Report to Australian Energy Market Operator, 26 June 2013.

It is also noted that in preparing the augmentation expenditure forecasts, CitiPower has used the demand forecast at each level of the network (i.e. zone substation, sub-transmission lines, HV feeders) to determine the future requirements. The sub-transmission lines and HV feeder forecasts are derived from the zone substation load forecasts, and these are provided in template 5.4 of the Reset RIN.

Step 2: Identify constraints on network assets

Under the probabilistic planning approach, CitiPower assesses and values the amount of load and energy that would not be supplied if an element of the network is out of service.

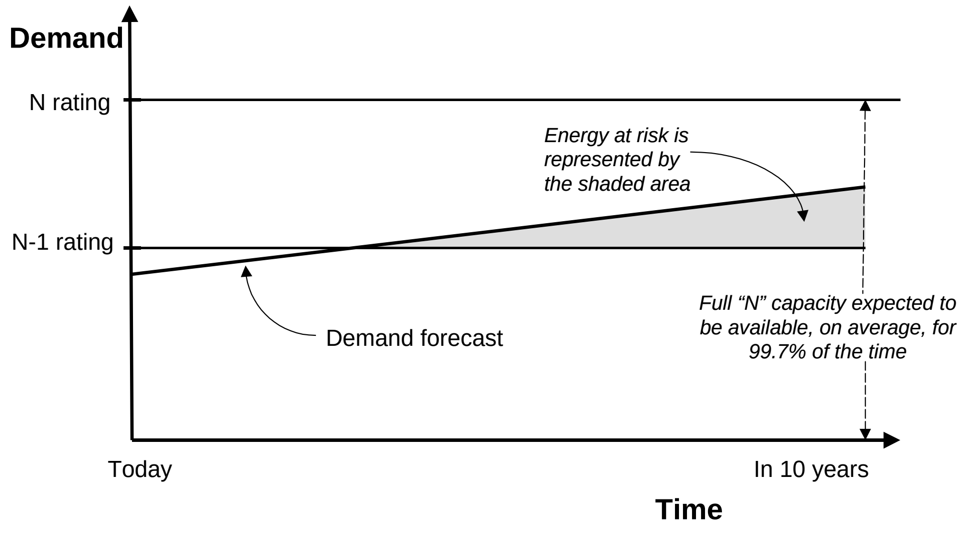
Take for example a zone substation. In this case, **energy at risk** is defined as:

> *The amount of energy that would not be supplied from a zone substation if a major outage of a transformer occurs at that station in that particular year, the outage has a mean duration of 2.6 months and no other mitigation action is taken.*

This statistic provides an indication of magnitude of loss of load that would arise in the unlikely event of a major outage of a transformer without taking into account planned augmentation or operational action, such as load transfers to other supply points, to mitigate the impact of the outage.

The capability of a zone substation with one transformer out of service is referred to as its 'N minus 1' rating. The capability of the station with all transformers in service is referred to as its 'N' rating. The relationship between the N and N-1 ratings of a station and the energy at risk is depicted in figure 4.3 below.

Figure 4.3 Relationship between N, N-1 rating and energy at risk



Source: CitiPower, *Distribution Annual Planning Report*, December 2014, p. 26.

Note that:

- under normal operating conditions, there will typically be more than adequate zone substation capacity to supply all demand; and
- the probability of prolonged outages of a zone substation transformer leading to load interruption is typically very low.

Step 3: Assess energy at risk against risk thresholds

The amount of energy at risk, as determined by step 2, is compared against CitiPower's internal policy to determine whether the energy at risk is sufficient to trigger a review of the network constraint.

An extract of the planning policy from the *Network Augmentation Planning Policy & Guidelines* is provided in table 4.1.

Table 4.1 Planning policy overview

Asset			Planning Criteria Trigger to Review Project Risks					
Type	Format	Section	Load Magnitude	Nominal Security Standard	Customer Interruption Time	Load Control Scheme	Maximum Load* as % of Rating	Maximum Time over Firm rating, Hours
Sub-transmission lines	Radial Overhead Line (Rural)	3.3.1.1	<20MVA	N	Best Practice	N/A	110	80
	Looped Line (Rural and Urban)	3.3.1.2	>20MVA	N-1	<1 minute	^Plant Protection	120	120
	Meshed Cable (CBD)	3.3.1.3	Any	N-1	<1 minute	N/A	120	120
	Meshed Cable Enhanced Security (CBD)	3.3.1.4	Any	N-2 after 30 minute switching	<1 minute	N/A	120	120
Sub transmission zone substations	Single Transformer Zone Substation (Rural)	3.3.2.1	<15MVA	N	Best Practice	N/A	100	0
	Multiple Transformer Banked Zone Substation (Rural)	3.3.2.2	15-20MVA	N-1	<4 hours	N/A	110	120
	Multiple Transformer Switched Zone Substation (Rural and Urban)	3.3.2.3	>15MVA	N-1	<1 minute	^Plant Protection	110	120
	CBD Zone Substations	3.3.2.3	>15MVA	N-1	<1 minute	N/A	100	0
Distribution lines	Radial Line (Rural Short & Rural Long)	4.2.1	Any	N	Best Practice	N/A	100	0
	Looped Line (Rural Long)	4.2.2	Any	N	Best Practice	N/A	80	0
	Looped Line (Urban & Rural Short)	4.2.3	Any	N	Best Practice	N/A	67	0
	Looped Line (Urban - CitiPower)	4.2.3	Any	N	Best Practice	N/A	67	0
	CBD Cable	4.2.4	Any	N	Best Practice	All in group except 1	100	0
						1 x standby	0	0
	SWER	4.2.5	<125kVA	N	Best Practice	N/A	125	0
Trans lines and Zone	Economic Criteria	>$1M Project value	The Annualised Cost of the Capital Project is less than the reduction in Annual Value of Expected Energy at Risk					

Source: CitiPower, *Network Augmentation Planning Policy & Guidelines*.

Step 4: Options analysis

Where the energy at risk is sufficient to trigger a review of the network constraints, as determined by step 3, then CitiPower assesses a range of options to address the network constraint.

For smaller augmentation projects, CitiPower conducts a detailed investigation into possible network and non-network solutions to address the network constraint. Further discussion of non-network solutions is contained in section 4.2.4.

For large augmentation projects over $5 million that are subject to a RIT-D, CitiPower undertakes a detailed assessment process to determine the economic efficiency of different investment options, including non-network solutions.

To determine the economically optimal level and configuration of distribution capacity (and hence the supply reliability that will be delivered to customers) for the purposes of the RIT-D, it is necessary to place a value on supply reliability from the customer's perspective.

Estimating the marginal value to customers of reliability is inherently difficult, and ultimately requires the application of some judgement. Therefore, CitiPower relies upon surveys undertaken by the AEMO to establish the VCR. For the purposes of the Regulatory Proposal, CitiPower has used the values for Victoria set out in AEMO's *Value of Customer Reliability Review* published in September 2014,[25] as set out in table 4.2.

Table 4.2 AEMO's value of customer reliability

Sector	VCRs for 2013 ($/kWh)	VCR for 2014 ($/kWh)
Residential (Victoria)	27.19	24.76
Commercial (NEM)	113.05	44.72
Agricultural (NEM)	147.76	47.67
Industrial (NEM)	44.93	44.06[26]
Composite- all sectors		39.50

Source: AEMO

The values have been applied in a manner consistent with AEMO's *Application guidelines* published in December 2014.[27]

The large reduction in the AEMO VCR values between 2013 and 2014 resulted in the deferral of some anticipated projects from the 2016–2020 regulatory control period to 2021 and beyond. This includes the deferral of the redevelopment and upgrade of Prahran zone substation, the installation of a third transformer at Kew zone substation and the construction of new 11kV feeders from North Richmond zone substation.

25 AEMO, *Value of Customer Reliability Review*, Final Report, September 2014.

26 Excludes industrial customers that are directly connected to the transmission network.

27 AEMO, *Value of customer reliability—application guide, final report*, December 2014. Available from: http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review.

Step 5: Selection of preferred option

For projects subject to RIT-D, CitiPower prepares a list which identifies all credible options to address the identified need, which includes both network and non-network solutions. Except where the options are to address a reliability issue, market benefits and costs of each option will be quantified. The credible option with the highest net economic benefit will receive the highest ranking and be the preferred option. Cost estimates have been obtained from a supplier for each material augmentation project, and where the projects have already commenced, detailed cost estimates have been utilised that have been through CitiPower's robust internal governance process.

For other augmentation projects, the most cost effective solution that also satisfies the risk based triggers in the Planning Guidelines is chosen as the preferred option. Detailed cost estimates have been derived from historical project costs for similar projects, where materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

Non-demand driven augmentation expenditure

As noted previously, augmentation expenditure may also be driven by non-demand factors such as:

- ensuring the security of supply of the network; and
- maintaining reliability and quality of supply of the network.

Security of supply is often considered alongside a demand-driven augmentation project. For example, this includes CitiPower's obligations under the Electricity Distribution Code to strengthen the security of supply in the Melbourne CBD.

Reliability of supply issues are often linked to replacement needs on the network. However, replacement projects can result in load being temporarily or permanently shifted around the network, leading to a need to augment the network. For example, the decommissioning of CitiPower's 22kV sub-transmission network will result in load being permanently shifted, and will drive the need to provide replacement capacity in the areas of the network taking up this load shift.

Quality of supply issues in the network are identified during the process to identify possible demand-driven constraints. That is, CitiPower considers whether the forecast changes in demand, both changes in load growth and embedded generation (e.g. solar PV growth), may result in the prospective fault current or voltage levels being outside the allowable limits.

Where there is no augmentation project planned for forecast changes in demand for a particular network asset where quality or security of supply issues have been identified, then CitiPower considers options to address the non-demand driven identified need.

CitiPower has undertaken a bottom-up build of the costs to address any forecast quality or security of supply issues on the network. Where the cost of the most expensive credible option is more than $5 million, CitiPower has applied the RIT-D process to determine the preferred option to address the quality or security of supply issue.

4.2.4 Non-network alternatives

This section discusses the consideration, and use, of non-network alternatives.

Consideration of non-network alternatives

Non-network solutions are an important component for the effective operation of the network and can involve either the reduction of customer electricity demand at peak times or the direct supply of electricity at the distribution level.

Effective and prudent use of non-network solutions can reduce the need for network augmentation and associated maintenance costs resulting in lower electricity bills for consumers.

There are a range of non-network solutions that can be used by electricity networks including:

- automated, contracted or voluntary demand management;
- shifting appliance or equipment use from peak periods to non-peak periods (eg: controlled load (off-peak) water heating);
- operating appliances at lower power demand for short periods (eg: air conditioner load control);
- converting the appliance energy source from electricity to an alternative (eg: switching from electric to gas heating);
- use of energy efficiency programs;
- use of pricing structures, such as Time of Use tariffs, to change consumer consumption patterns;
- voluntary load curtailment by customers, such as in response to a request to reduce electricity usage;
- voluntary load shedding and disconnection of non-critical loads by customers;
- power factor correction of customer equipment;
- operation of embedded generators using conventional and renewable fuel sources;
- use of stand-by generators to enable load transfer; and
- storage devices such as batteries that can store energy in times of reduced demand and convert back to electricity at times of peak demand.

When a network constraint is identified, a review of options that includes both reducing demand and increasing capacity is initiated. The goal is to find the most efficient and prudent solution. This may be a non-network solution.

The framework and process by which CitiPower engages with non-network providers is set out in the Demand Side Engagement Strategy.[28] Importantly, CitiPower maintains a demand-side register for parties to notify their interest in being advised of developments relating to the planning and expansion of the networks. CitiPower will use this register not only to consult with interested parties, but also to determine the level of interest and ability to participate in the process for the development of non-network options.

The DAPR also provides preliminary information on potential opportunities to prospective proponents of non-network solutions at zone substations or on sub-transmission lines where remedial action may be required.

Use of non-network alternatives

CitiPower has undertaken a range of demand management activities in the current regulatory control period, including:

[28] CitiPower Pty /Powercor Australia Ltd, *Demand side engagement strategy*, 31 August 2013.

- operating an inner urban demand management program which involved trialling large commercial and industry customers served by the Richmond Terminal Station to reduce maximum demand on very hot days;
- entering into contracts with network support providers for co-generation facilities; and
- engaging a consultancy firm to undertake a review of present fault level mitigation strategies to determine their long term effects. This will facilitate connection of embedded generation.

A complete list of the non-network alternative projects that CitiPower has undertaken during the current regulatory control period, and those that it has selected to commence or continue during the 2016–2020 regulatory control period, are set out in the *Non-network alternative projects* attachment.

4.2.5 Use of Load Indices

To enhance the use of probabilistic planning, CitiPower had collaborated with EA Technology to develop Load Indices. The indices are intended to provide a high level indication of demand-related network risk and performance. They are also used to assess the reasonableness of bottom-up augmentation expenditure forecasts.

Background to Load Index

Ofgem introduced load indices into the electricity distribution regulatory framework in the United Kingdom, together with health indices. These were designed by Ofgem to tie specific price control network investment to specific in-period risk reduction associated with the condition and loading of assets. The metrics link the longer-term key network risk metrics to a measurable deliverable within the Ofgem price control.[29]

The load index measures applied in the UK have been adapted by CitiPower to accommodate the greater spread of load conditions on its network, reflecting the use of probabilistic planning standards rather than deterministic standards.

The load index, which is a measure of asset utilisation, is generated from two factors;

- demand driver – measure of maximum demand relative to firm capacity; and
- duration and energy driver – measure of hours or energy at risk.

The load indices have been developed to cover a range of conditions, and are placed on a scale from 1 to 10. An index of one indicates that there is no load at risk under peak load conditions. There are several bands for increasing times over firm capacity (N-1 rating). An index of nine or ten indicates that the load is approaching or even exceeding the N capacity, and that load shedding is likely to occur, resulting in significant loss of supply and/or time required to restore supply.

The bandings are intended to provide sufficient breadth and sufficient discrimination to both visualise/communicate the overall level of load, and to show the effects of modest load increases over the next few years. The bandings are shown in table 4.3.

[29] Ofgem, *Strategy consultation for the RIIO-ED1 electricity distribution price control – reliability and safety*, Supplementary annex to RIIO ED1 overview paper, 28 September 2012, p. 8, paragraph 2.6. Available from https://www.ofgem.gov.uk/ofgem-publications/47145/riioed1sconreliabilitysafety.pdf.

Table 4.3 Load index bands

Load Index	Condition	Load%		Hrs % Firm Capacity	
		>Minimum	≤ Maximum	>Minimum	≤ Maximum
1	N-1	0	90	N/A	N/A
2	N-1	90	100	N/A	N/A
3	N-1	100	110	N/A	N/A
4	N-1	110	…	N/A	100
5	N-1	110	…	N/A	250
6	N-1	110	…	N/A	500
7	N-1	110	…	N/A	750
8	N-1	110	…	750	7500
9	N	90	100	N/A	N/A
10	N	100		N/A	N/A

Source: CitiPower

CitiPower uses the load indices for zone substations and sub-transmission lines.

The load indices are straightforward to apply. Take for example the McIllwraith Place zone substation. Given the peak demand forecasts contained in the 2014 DAPR, CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk.

Table 4.4 Estimated energy at risk at McIllwraith Place (MP) zone substation

WPD	2015	2016	2017	2018	2019	2020
Summer demand (MVA)	142.6	148.7	153.3	155.8	158.0	159.9
Summer overload (%)	12.6	17.3	20.8	22.7	24.4	25.8
Annual energy at risk (MWh)	282	681	1184	1539	1914	2265
Annual hours at risk (hrs)	55	106	160	192	221	246

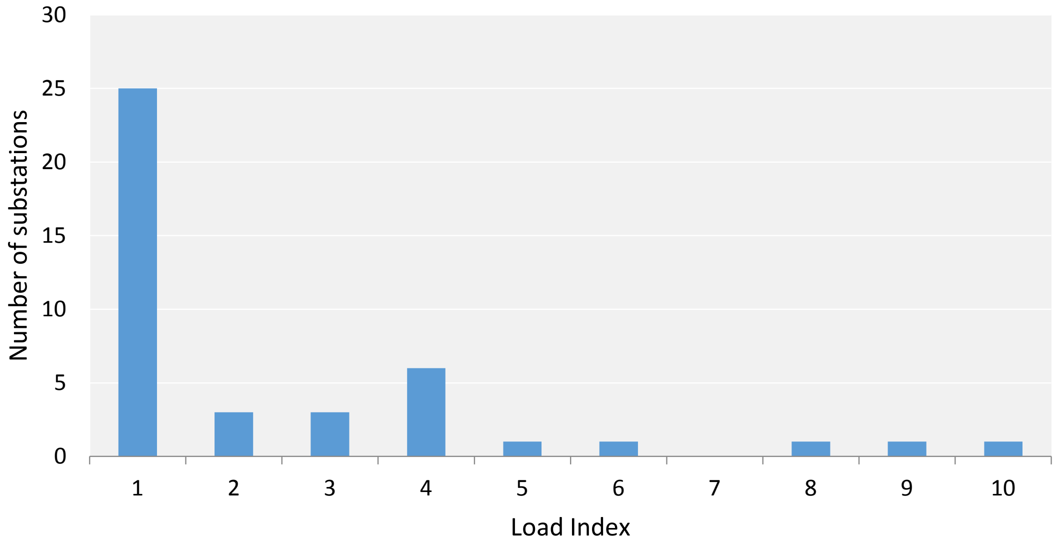
Source: CitiPower, *Distribution Annual Planning Report*, December 2014, p. 59.

Table 4.4 shows that in 2015, the summer overload above N-1 is forecast to be 12.6 per cent, and with 55 hours at risk. This indicates a load index of four.

Checking the reasonableness of the forecast

CitiPower's expected load index profile at the start of the 2016–2020 regulatory control period is shown in figure 4.4. This provides a visual tool to understand at a high level the loading and energy at risk on major assets.

Figure 4.4 Load index of CitiPower zone substations in 2016



Source: CitiPower

Similar to the HI approach, as zone substations move into the seven and higher categories, plans are required to manage or alleviate the loading constraints. The profile shows that CitiPower has several zone substations with a load index above seven, including one zone substation with an index of nine and one at ten. The load indices indicate that there is significant load at risk, and it is clear that CitiPower needs to augment the network.

The demand forecasts can be used to generate load index profile predictions for future years to check the appropriateness of the expenditure forecasts. The profiles are compared using a ‘do nothing’ approach, against the forecast augmentation projects to ensure that, over the forecast period, the load index profile for the total transformer fleet is appropriately managed.

A load index profile similar at the end of the forecast period to the current profile infers that:

- no changes to network planning processes are required over the forecast period;
- no backlog of pending augmentations at the end of the forecast period; and
- no significant reduction in utilisation is forecast.

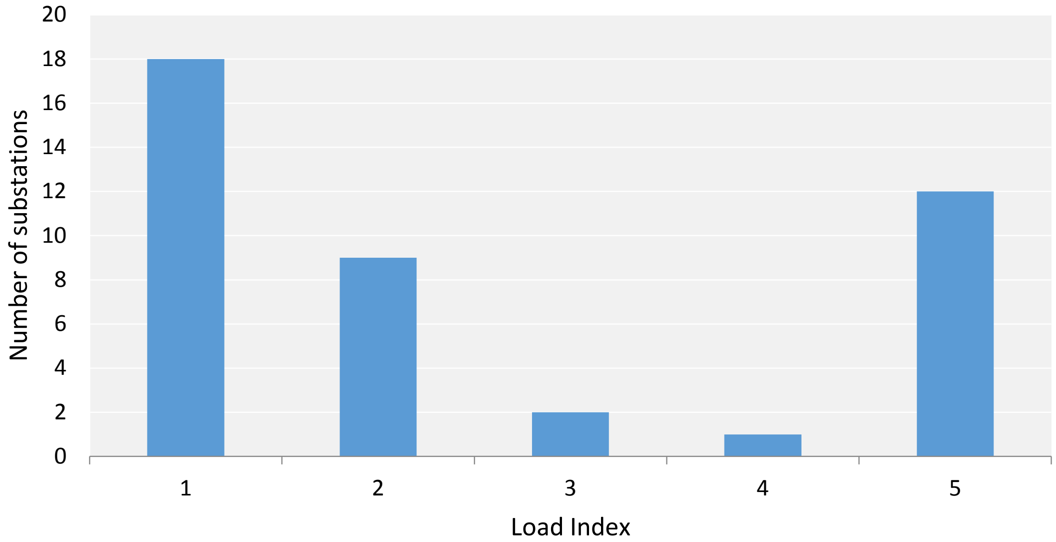
If the load index profile deteriorates over the forecast period, then it would suggest that a step up in expenditure is required.

Comparison with overseas

CitiPower adapted the UK load index measures to accommodate the greater spread of load conditions on its network, reflecting the use of probabilistic planning standards rather than deterministic standards.

If the scale that is applied in the United Kingdom was applied, then it would indicate that CitiPower has a large number of zone substations at the top of the scale.

Figure 4.5 2014 Load index profile at the start of 2016 using UK scale



Source: CitiPower

CitiPower understands that distributors in the United Kingdom are required to address assets with a load index above two. This would encompass over a third of CitiPower's assets.

4.2.6 Comparison of unit rates

As discussed in the regulatory proposal, benchmarking of costs across distributors can only be appropriate when the following conditions hold:

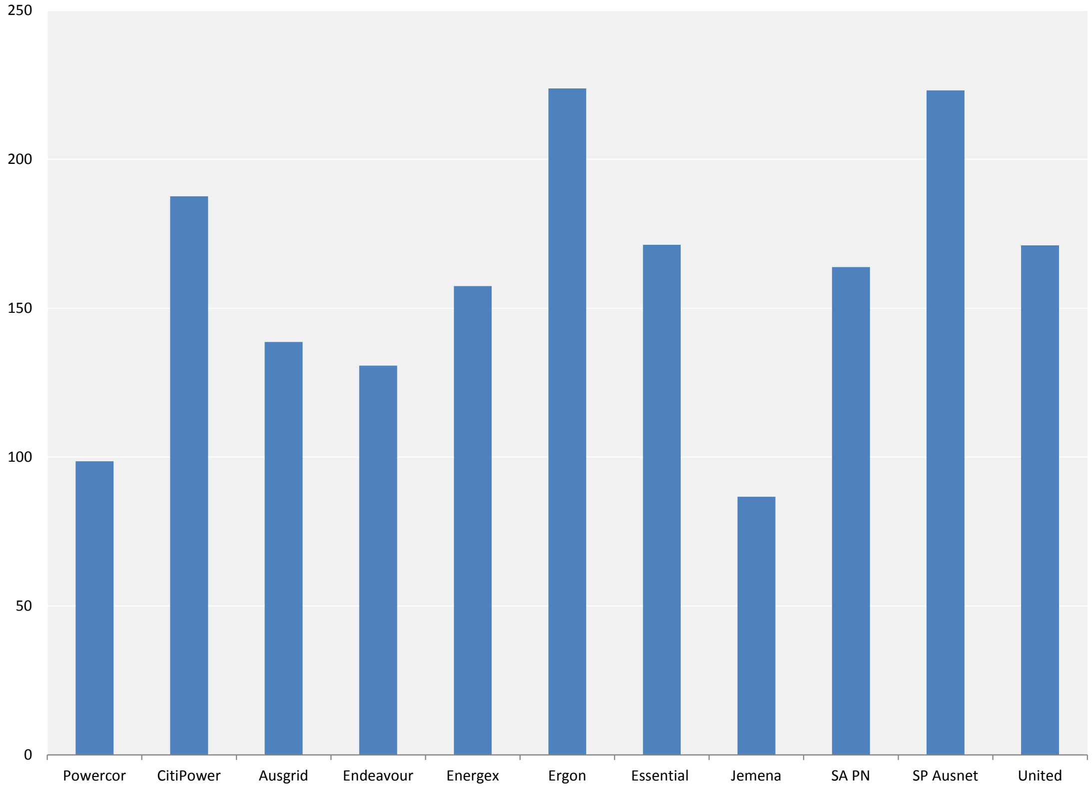
- consistent reporting and interpretations of costs;
- exogenous differences in operating environment are normalised; and
- costs reflect a representative and appropriate sample.

These conditions do not hold for the data for augmentations contained in the 2013 Category Analysis RIN, and therefore the AER should be cautious in using the data to inform any of its decisions for the Regulatory Proposal.

Example – upgrade of zone substations

Take for example the category of upgrade of zone substations. The unit rate data shown in figure 4.6 represents the average cost over the period from 2009 to 2013, calculated by dividing the total expenditure by the total volumes over the period. CitiPower's unit rate appears to be slightly above the average unit cost across all distributors, whereas Powercor's unit rate appears to be below the average unit cost.

Figure 4.6 Zone substations upgrades – capacity ($000/MVA, 2014)



Source: Category Analysis RIN, Powercor analysis
Note: distributors with no data have been excluded from the graph

The upgrade of a zone substation could involve:

- replacement of an existing transformer with a new transformer; or
- installation of a new transformer.

These activities could result in very different costs. The installation of a new transformer in a zone substation may involve works to the zone substation to provide space to cater for the new transformer, together with upgrade to the protection equipment or feeders. However, the replacement of an existing transformer with an increased capacity transformer may involve no additional works.

It is noted that CitiPower upgraded one zone substation at Bouverie/Queensberry (**BQ**) during the relevant period, which is not a statistically significant sample size to draw a conclusion on average costs. The upgrade to the building, located just north of the Melbourne CBD in the suburb of Carlton, involved extensive works to the building for it to be brought up to standard to cater for the new transformer. In contrast, Powercor upgraded five zone substations with a mix of projects, including upgrading the transformers at the Sunshine East (**SSE**) zone substation as well as installing a new transformer at the Castlemaine (**CMN**) zone substation.

The method to calculate the Megavolt Ampere (**MVA**) added appears to differ between distributors. The nameplate rating relates to the ongoing capacity determined by the plant manufacturer, whereas the cyclic rating is the capacity of the transformer after jurisdictional planning standards, the cooling profile of the transformer and environmental conditions are taken into account. The cyclic rating of a transformer is higher than the nameplate rating. CitiPower has used the nameplate rating to determine the MVA added by each transformer, however it appears that other distributors have used the cyclic rating.

It is clear that distributors have interpreted the data requirements differently, costs vary depending on the type of upgrade of capacity to the zone substation undertaken, and in some cases the sample sizes are not large enough to determine unit costs. As a result, the data should not be relied upon for benchmarking purposes.

4.3 Historic spend

In the 2011–2015 regulatory control period, CitiPower delivered a significant portion of the CBD security of supply upgrade plan, as well as the Metro capacity project. This has included the delivery of:

- new 66kV switching station as part of the Victoria Market (**VM**) zone substation with GIS 66kV switchgear, together with two new sub-transmission cables from Bouverie/Queensberry (**BQ**) zone substation to VM, and a new sub-transmission cable from VM to near Brunswick terminal station (**BTS**);
- two new sub-transmission cables from BQ to near the proposed new Waratah Place (**WP**) zone substation; and
- redevelopment of BQ as a 66kV zone substation with GIS 66kV switchgear, together with a new 66kV sub-transmission cable from BQ to near BTS.

CitiPower also closed out the construction of a new zone substation at Southbank (**SB**), which replaced the decommissioned South Melbourne (**SM**) zone substation. This was the first part of the plan to decommission the 22kV sub-transmission network and integrate the supply into the 66kV sub-transmission network. As part of this plan, an additional 11kV switchboard and transformer was installed at Balaclava (**BC**) zone substation and a new sub-transmission line from RTS to Toorak (**TK**) was also constructed (which forms part of the sub-transmission loop that serves BC) in readiness to decommission the ageing Prahran (**PR**) 22kV zone substation.

To allow further embedded generation into the network and to manage the fault levels from existing generation, 'Normally Open Auto Close' schemes were installed which open the bus-tie circuit breakers at the four constrained zone substations to divide the fault current path, as well as a 66kV reactor for extra impedance at a zone substation.

Several new 11kV feeders were also constructed, as well as new capacitor banks at two zone substations. CitiPower uprated the sub-transmission line from Springvale terminal station (**SVTS**) to Riversdale (**RD**) zone substation together with United Energy Distribution.

Overall, CitiPower forecasts that it will underspend its augmentation regulatory allowance in the 2011-2015 regulatory period by 35 per cent. The primary driver for the underspend was the delay to the CBD Security Upgrade and Metro projects as a result of community and local government objections to the planning permit for the upgrade to the Brunswick Terminal Station (**BTS**). The timeline for the delays to BTS were shown in Figure 3.17. As a result, the following CBD security of supply distribution works were delayed and are now proceeding to revised targets:

- establish two sub-transmission cables from BTS to BQ zone substation;
- establish a sub-transmission cable from BTS to VM zone substation, and associated protection equipment;
- install two transformers at the rebuilt WP zone substation, 16 circuit breakers and associated switchgear and protection equipment;

- establish two sub-transmission cables from BQ to WP zone substation and associated protection equipment; and
- establish 66kV connections and associated protection co-ordination at BTS.

Related works to establish additional 11kV feeder transfer capacity and distribution remote switching at the Little Bourke Street (**JA**), McIllwraith Place (**MP**), Celestial Avenue (**WA**) and Little Queen (**LQ**) zone substations were also impacted by the BTS delay. These works are intended to be carried out in conjunction with demand growth projects on 11kV feeders from these zone substations at the completion of the CBD Security upgrade project.

As a result of delays to BTS, CitiPower undertook a number of alternative projects in a co-ordinated strategy with Jemena, United Energy, AusNet Services and AEMO. These projects were designed to mitigate some of the risks in the short term from the BTS delay, including:

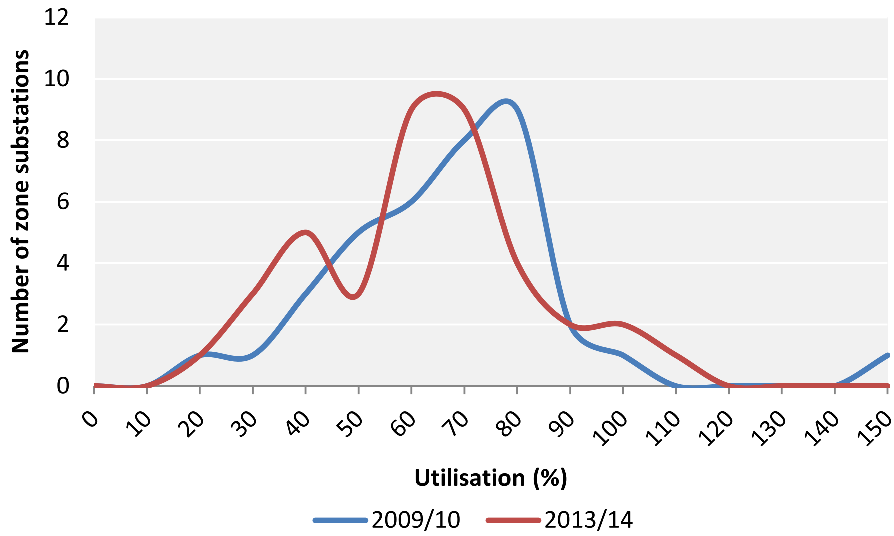
- installation of temporary transformer capacity at Richmond terminal station (**RTS**) until the upgrade of BTS is completed;
- construction of an emergency 66kV sub-transmission line from RTS to Templestowe terminal station; and
- construction of an emergency 66kV sub-transmission line from RTS to Malvern terminal station.

4.3.1 Efficiencies of past actual expenditure

The AER has considered the decreasing average utilisation levels at zone substations in the NSW draft determinations to suggest that there is excess capacity in their network that needs to be utilised ahead of additional augmentation investment.[30]

CitiPower notes that its average utilisation has also fallen over the period from 2008/09 to 2012/13 in its zone substations, from 63 per cent to 58 per cent.

Figure 4.7 CitiPower utilisation profile for zone substations



Source: Jacobs analysis for CitiPower

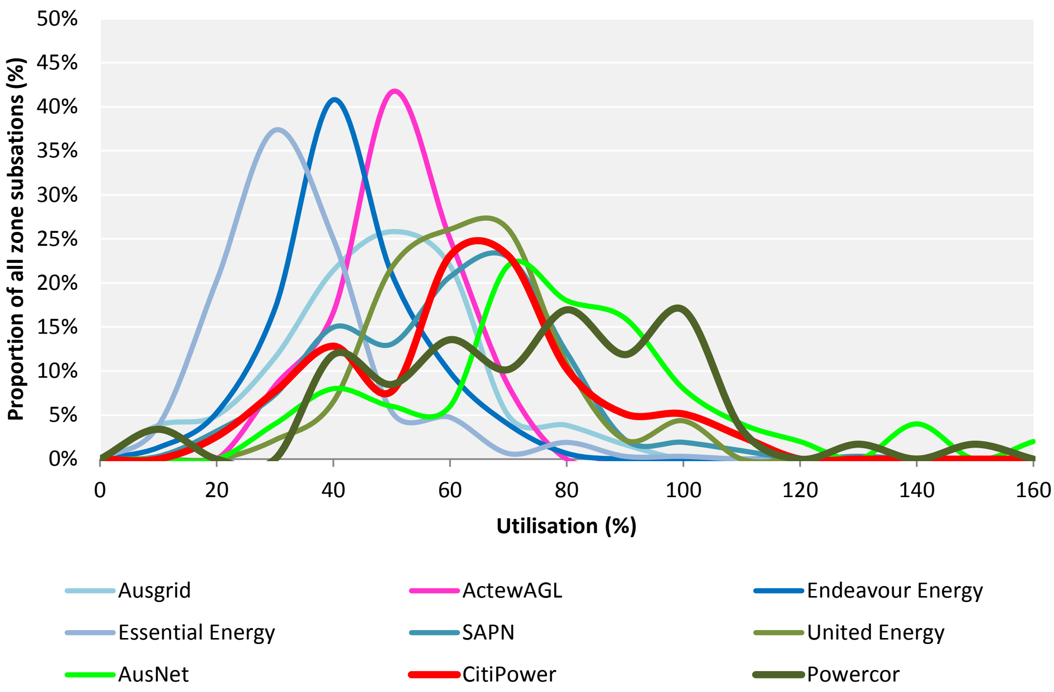
30 For example, see AER, *Draft decision Ausgrid distribution determination 2015–16 to 2018–19*, November 2014, p.6-38.

The fall in average utilisation is not a particular concern for CitiPower, as augmentation is only undertaken to address a particular localised constraint. For example, CitiPower has upgraded the BQ zone substation in Carlton and a new zone substation in the SB area to address peak demand constraints as well as replacement needs. The additional zone substation may have lowered the average utilisation, but this does not suggest that augmentation expenditure has created excess network capacity.

The primary concern for CitiPower is managing the zone substations that have a very high utilisation rate. It is noteworthy that the number of zone substations with a peak demand utilisation rate over 90 per cent increased from two in 2008/09 to three in 2012/13. As a result, CitiPower is managing additional risk on its network.

The utilisation profiles, however, demonstrate that the probabilistic planning approach used in Victoria compared to the deterministic planning standard that was then used in the northern states results in higher asset utilisation on average. Figure 4.8 shows the utilisation profiles across distributors in NSW, Queensland, Victoria and South Australia normalised for the number of zone substations.

Figure 4.8 Normalised zone substation utilisation 2012/13 for all distributors



Source: AER Category Analysis RIN, Jacobs analysis
Note: the data for SA Power Networks relates to 2013/14

4.4 Forecast spend

CitiPower requires a 5 per cent increase in augmentation expenditure compared to its actual spend during the 2011–2015 regulatory control period. However, if the CBD Security project had been undertaken as planned in the 2011–2015 regulatory control period, then CitiPower would be seeking a reduction in expenditure for the 2016–2020 regulatory control period.

The key drivers underpinning the forecast augmentation capital expenditure are:

- localised demand growth in established residential and commercial areas;

- need to provide replacement capacity following the decommissioning of the 22kV sub-transmission network. This strategy is being co-ordinated with AusNet Services to alleviate the need for like-for-like replacement of the ageing 22kV assets both within the terminal stations and in CitiPower's network; and
- completion of the CBD Security of Supply and Metro projects.

Each of these drivers is discussed below.

Demand based growth

A large number of small projects to increase capacity in the feeder network are driven by expected growth in peak demand.

Projects to install a third transformer at the BQ zone substation, and the upgrade of the Dock Area (**DA**) zone substation from 22kV to 66kV supply out of West Melbourne termination station (**WMTS**) were intended to be undertaken in the 2011–2015 regulatory control period, but were efficiently deferred. These will now be undertaken in the 2016–2020 regulatory control period. The latter project is also required as a result of the decommissioning of the 22kV sub-transmission network from WMTS.

Checking the reasonableness of the forecasts

As noted above, CitiPower is able to undertake a top-down check that its expenditure forecasts are reasonable, sustainable and will enable it to prudently and efficiently manage the network constraints by using the load index to generate profile predictions for future years.

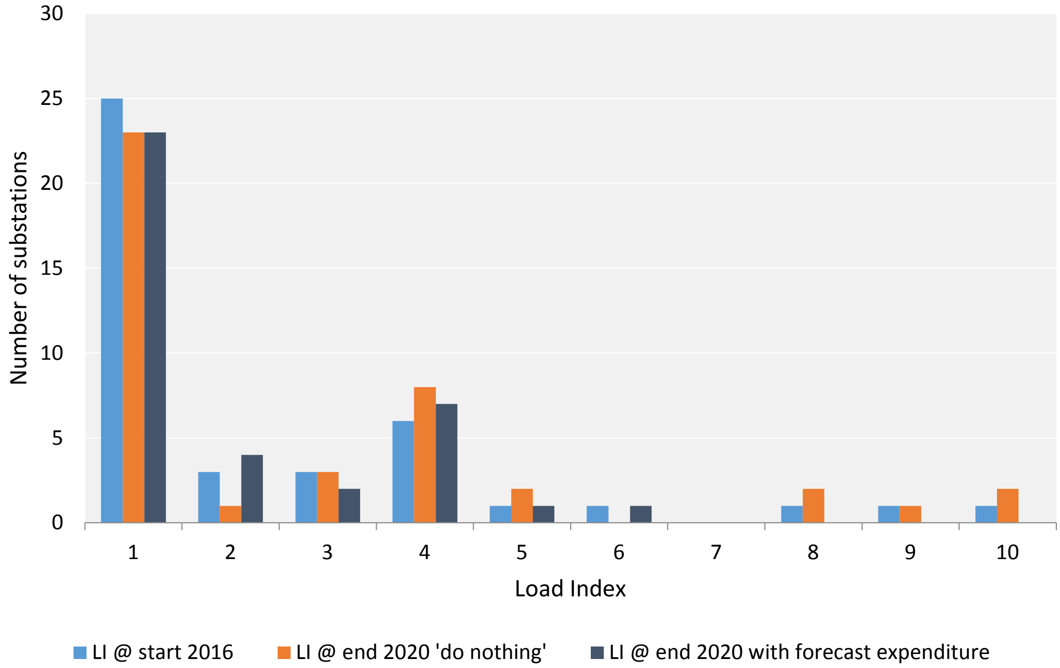
CitiPower has created the load index profile at the start of the 2016–2020 regulatory control period and compared that to:

- the profile that would occur in the 'do nothing' scenario over the 2016–2020 regulatory control period; and
- the profile that would occur if it undertakes the investments set out in this regulatory proposal.

The comparison of these profiles allows CitiPower to ensure at a top-down level that the network constraints at zone substations or on sub-transmission lines are being appropriately managed. This is particularly applied to that portion of the profile that is greater than or equal to seven.

Using transformers in zone substations, figure 4.9 shows that CitiPower's forecast expenditure is reasonable as it is able to appropriately maintain the number of transformers with a load index of seven. In respect to the transformers which at the start of 2016 had a load index of above seven, one was due to the delay in BTS (WB) and the other two (Albert Park (**AP**) and North Richmond (**NR**)) have fault level constraints and will be addressed through non- demand related projects.

Figure 4.9 Load index at the end of 2020 with and without augmentation



Source: CitiPower

In the 'do nothing' scenario, five zone substations will be approaching or exceeding the normal capacity of the transformers at the time of peak demand, which may result in outages. With the proposed augmentation projects, no zone substation will be exposed to such risk.

Non-demand driven augmentation expenditure

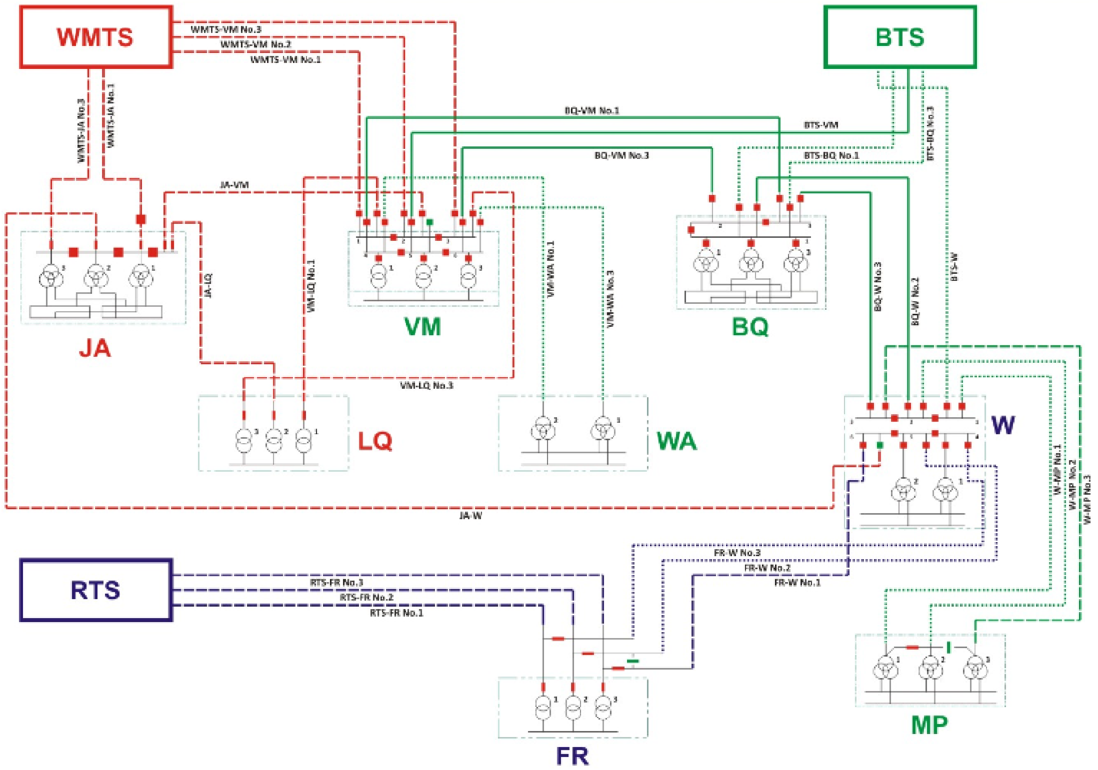
Completion of the CBD Security of Supply and Metro projects

The Melbourne CBD security upgrade is an obligation under clause 3.1A of the Victorian Electricity Distribution Code. This obligation followed the publication of a Regulatory Test final report that economically justified the scope of the works defined to upgrade the 66kV sub-transmission network in the Melbourne CBD to an 'N-1 Secure' standard.

The CBD Security of Supply and Metro projects were intended to be completed during the 2011-2015 regulatory control period. However, as a result of community and local government objections to the planning permit for the BTS upgrade the works were delayed.

The works will now be completed by the end of 2017. The expected schematic for the network following the completion of these works is shown in figure 4.10.

Figure 4.10 Expected schematic of the network following completion of the security works



Source: CitiPower

Replacement of the 22kV sub-transmission network

CitiPower has commenced a program to replace the 22kV sub-transmission network with the 66kV sub-transmission network. The program will involve augmentation of the network as it will result in a need to replace this capacity through the construction of feeders and new transformers to allow for the decommissioning-related works to take place.

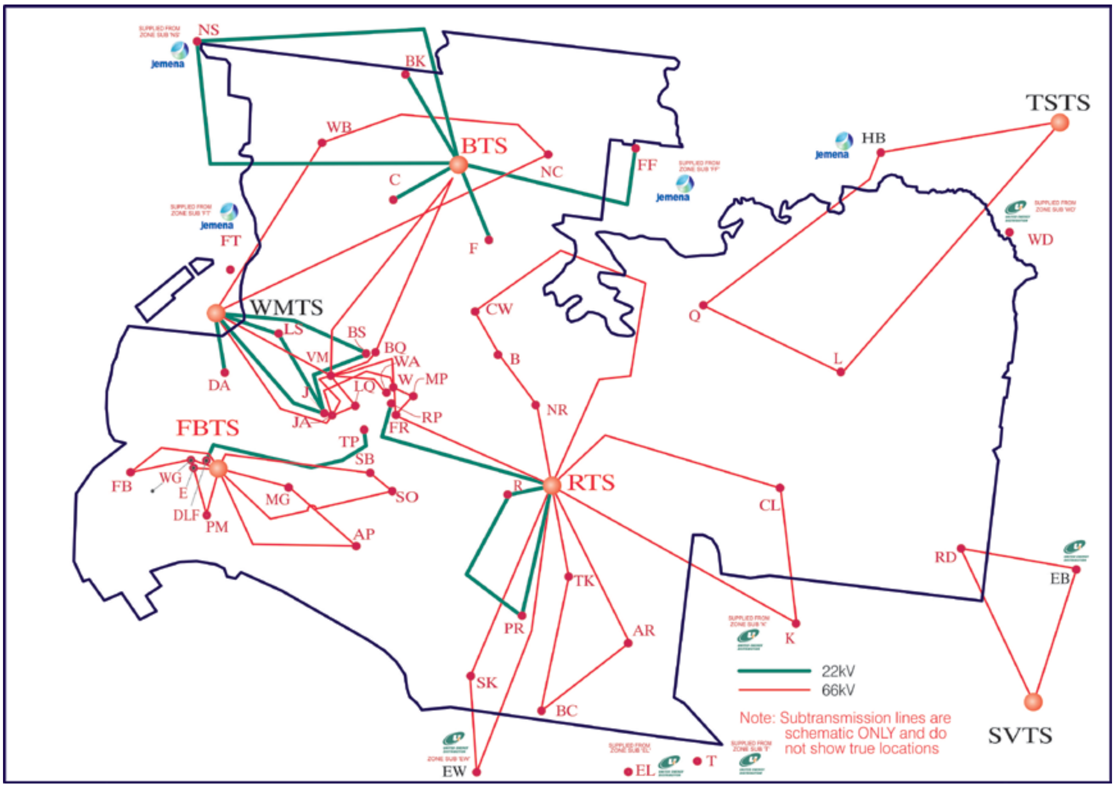
The replacement program is necessary as many of the ageing assets that are in poor condition exist within the 22kV sub-transmission network, including transformers and indoor switchboards within existing zone substations.

Some of these zone substations have secondary voltages of 6.6kV, which is inconsistent with the present 11kV standard in the CBD and inner suburbs. These non-standard 6.6kV secondary voltages have many technical limitations when compared with the standard 11kV secondary voltage. Having 6.6kV distribution feeders limits system flexibility with regard to load transfers and effectively creates islands within the network. CitiPower intends to upgrade the associated 6.6kV distribution network to 11kV as part of the replacement program.

Operation of the sub-transmission network at the higher voltage of 66kV also reduces the amount of distribution losses from the network.

A schematic of the current 22kV sub-transmission network is set out in figure 4.11.

Figure 4.11 Schematic of the 22kV sub-transmission network



Source: CitiPower

CitiPower intends to retire three zone substations and upgrade one zone substation supplied from WMTS 22kV, two from RTS and one zone substations supplied from Fishermans Bend terminal station (**FBTS**) over the 2016–2020 regulatory control period, as set out in table 4.5.

Table 4.5 Decommissioning the 22kV sub-transmission network

Zone substation	2020 transformer Health Index (no augmentation)	Serving terminal station	Solution
Dock Area (DA)	4.34, 5.74, 5.81	West Melbourne terminal station (**WMTS**)22	Upgrade to 66kV and connect to WMTS66
Bouverie Street (BS)	8.31, 9.12, 9.12	WMTS22	Transfer load to Bouverie/ Queensberry (**BQ**) and decommission
Laurens St (LS)	4.18, 5.39, 5.17 (circuit breakers both 10.30)	WMTS22	Transfer via new 11kV feeders to BQ and decommission
Spencer St (J)	6.42, 6.45, 5.51, 4.84	WMTS22	Transfer load to Little Bourke Street (**JA**) and decommission
Tavistock Place (TP)	6.81, 7.84	Fishermans Bend terminal station (**FBTS**)	Transfer via new 11kV feeders to Southbank (**SB**) and decommission
Russell Place (RP)	9.76, 9.32, 7.65	Richmond terminal station (**RTS22**)	Transfer load via new 11kV feeders to new Waratah Place (**WP**) zone substation and decommission
Prahran (PR)	4.08, 5.53, 6.39 (most circuit breakers above 9.19)	RTS22	Transfer load to Balaclava (**BC**) via feeders that are currently being constructed, and decommission

Source: CitiPower

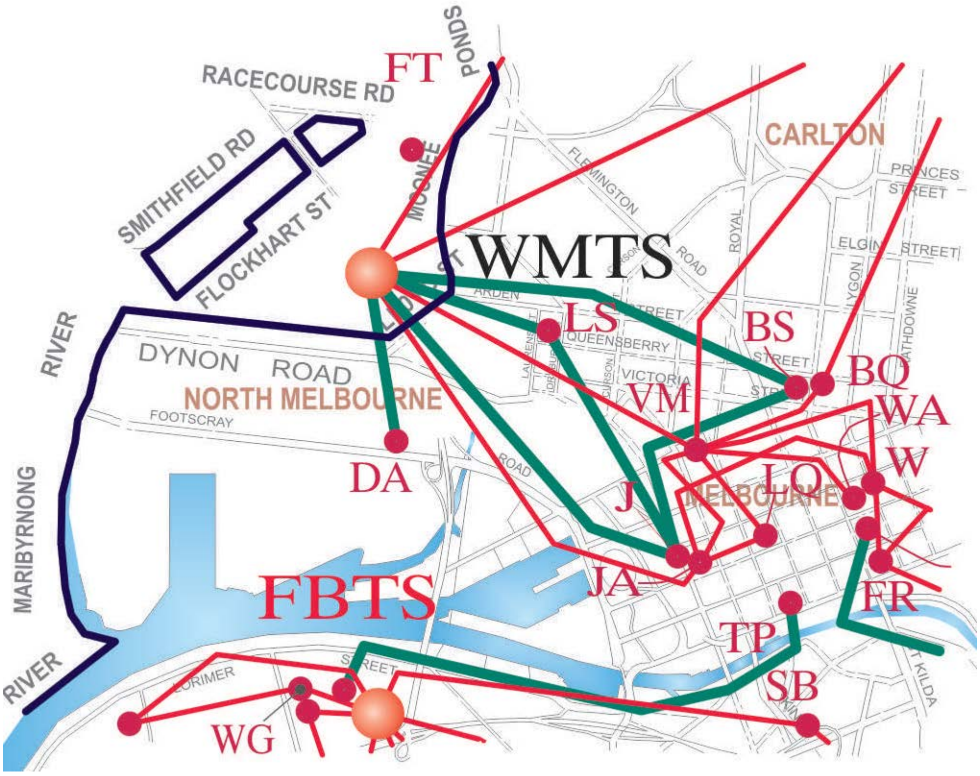
Many of the zone substations targeted for decommissioning are served by WMTS. AusNet Services is undertaking works to rebuild the WMTS due to the condition and age of the plant and equipment.[31]

Given CitiPower's strategy to retire the 22kV sub-transmission network, it would be inefficient for AusNet Services to rebuild the 22kV switchyard at WMTS. AusNet Services has advised CitiPower that it will avoid costs of around $41 million of not proceeding with the replacement of the WMTS22 switchyard and transformers.[32] The replacement of CitiPower's assets served from WMTS22 must therefore be co-ordinated with the timing of the AusNet Services rebuild of WMTS.

31 AER, *SP AusNet Transmission Determination 2014–15 to 2016–17*, Final Decision, January 2014, pp. 73-74. http://www.aer.gov.au/sites/default/files/AER%20final%20decision%20for%20SP%20AusNet%27s%202014-17%20regulatory%20control%20period%20-%2031%20January%202014.pdf.

32 AusNet Services, *Letter to CitiPower re: West Melbourne Terminal Station 22kV Asset Replacement Avoided Cost*, 4 March 2015.

Figure 4.12 Zone substations served from West Melbourne terminal station



Source: CitiPower

The TP zone substation must be decommissioned at the same time as the J zone substation. This is because TP and J form a CBD feeder group with secondary voltages of 6.6kV rather than feeders at 11kV, and provide back-up for each other. The transfer of the load from TP to SB will involve the construction of new 11kV feeders across the Yarra River.

The DA zone substation is served by a sub-transmission line from WMTS that is built to the 66kV standard, despite currently only supplying electricity at 22kV. This will be upgraded to 66kV as part of the replacement works.

4.5 Material augmentation projects

Demand-driven augmentation projects, where the cost of the most expensive credible option is greater than $5 million, are required to satisfy the regulatory investment test for distribution (**RIT-D**). This test was introduced on 1 January 2014.

Where CitiPower commenced assessing a project prior to the RIT-D commencement date, then those projects were assessed under the Regulatory Test.

For those augmentation projects where demand is not the primary driver of the project, then a RIT-D or Regulatory Test is not required. CitiPower has provided an explanation of the options and preferred solution for these material projects.

4.5.1 Forecast capital expenditure that has satisfied the regulatory test

This section identifies the forecast augmentation capital expenditure for the 2016-2020 regulatory period that have satisfied the regulatory test, RIT-D or the regulatory investment test for transmission (**RIT-T**).

Table 4.6 Network service projects that have satisfied the regulatory tests

Project name	Test type	Cost ($ million, 2015)	Date of final report(s)	Material project no.
BTS upgrade	Regulatory Test	30.8	14 August 2008 31 May 2011	AUG 11
MP to BQ and WP 11kV feeders	Regulatory Test	6.99	July 2014	-

Source: CitiPower
Note: direct costs excluding real escalation

Each of these projects is discussed in turn below.

BTS upgrade and CBD security of supply

Following significant outages in the Melbourne CBD in 2001, CitiPower undertook a comprehensive review of the planning criteria and options to improve redundancy into the CBD. CitiPower provided a proposal to the then regulator, Essential Services of Commission (**ESC**) in 2006 which recommended, among other things:[33]

- the 66kV sub-transmission network planning criteria for the CBD should be changed from the existing N-1 criterion to the more onerous 'N-1 secure' criterion, where the network can withstand the loss of one network element and be re-configured to withstand a further outage without loss of supply. However, during the anticipated 30 minutes it would take to reconfigure the network there is a risk of loss of supply should the second loss occur;
- the development of Brunswick Terminal Station (**BTS**) to a 220/66kV station provides the best long-term solution for the CBD supply in terms of costs, achievability, ultimate capacity, load reduction at West Melbourne terminal station (**WMTS**) and Richmond terminal station (**RTS**), and the capability to transfer load between adjacent terminal stations; and
- both the West Brunswick (**WB**) – Brunswick (**C**) – Northcote (**NC**) 66kV sub-transmission loop (ex WMTS) and the Collingwood (**CW**) – Collingwood (**B**) – North Richmond (**NR**) 66kV sub-transmission loop (ex RTS) should be connected to BTS.

At that time, CitiPower submitted a regulatory test to the ESC in support of its proposal. In its final decision, the ESC determined that the Electricity Distribution Code be amended to oblige CitiPower to deliver this higher level of security to CBD and inner Melbourne customers.[34]

A separate regulatory test in 2008 revealed that the upgrade to the BTS was the most cost effective option to relieve the projected capacity constraints at RTS and WMTS and yielded the greatest net economic benefit in the majority of reasonable scenarios. The option also included:[35]

33 Sinclair Knight Merz, *CitiPower Review of CBD security of supply and planning standards, updated final report*, 22 August 2006, p. 40.

34 ESC, *Final Decision CBD Security of Supply*, February 2008, p. vi.

35 CitiPower, *Brunswick Terminal Station*, Final Report, 2008.

- installation of two 66kV 120MVA sub-transmission cables from BTS to BQ with protection works at each end;
- installation of two 66/11kV 60MVA transformers and 11kV switchgear and secondary works at BQ, as well as nine 66kV circuit breaker and isolators; and
- refurbishment of BQ and civil works for switch bay floors.

Following the rejection of the BTS planning permit application by Moreland City Council in June 2010, CitiPower, AEMO and AusNet Services worked together with interested stakeholders to develop a range of options to address the projected capacity constraints, including a number of alternative design options. Given the nature and cost of the alternative supply options varied from those originally contemplated in 2008 regulatory test, the regulatory test was reapplied for the BTS component in 2011.

The revised regulatory test recommended the upgrade of BTS, with 220kV gas insulated switchgear (**GIS**) located in a new building, 22kV switchgear located in an existing building but with improvements for visual amenity, 66kV GIS located inside a new building and transformers located in an enclosure. [36]

It is also noted that part of the revised regulatory test was to reduce the load at RTS by transferring the RTS-CW-B-NR-RTS 66kV sub-transmission loop to BTS.[37] As a result of delays to the construction of the 66kV point of supply at BTS, a constraint subsequently arose on the RTS-FR sub-transmission lines.

An alternative solution was identified that would address both the constraints at RTS as well as on the RTS-FR sub-transmission lines. That alternative solution involves the transfer of the McIllwraith Place (**MP**) zone substation from being served by RTS and the RTS-FR sub-transmission cables to instead being served by BTS. To achieve this alternative solution, CitiPower proposes to reconfigure existing cables and construct a new sub-transmission cable:

- BTS-W, construct a new sub-transmission cable;
- FR1-WP1, reconfiguring the existing FR1-MP1;
- FR2-WP2: reconfiguring the existing FR2-MP2;
- MP1-WP1, reconfiguring the existing FR1-MP1; and
- MP1-WP2: reconfiguring the existing FR2-MP2.

The estimated cost of this alternative solution is significantly lower than the original solution. This project has a planned commissioning date of November 2017.

Overall, these works at BTS will enable CitiPower to carry out its obligations under the Electricity Distribution Code to increase resilience into the Melbourne CBD through the security of supply and metro projects.

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[36] NERA Economic Consulting, *Proposed augmentation for Melbourne inner suburbs and CBD supply – a final report prepared for CitiPower and AEMO*, 31 May 2011, pp. vi, xii.

[37] NERA Economic Consulting, *Proposed augmentation for Melbourne inner suburbs and CBD supply – a final report prepared for CitiPower and AEMO*, 31 May 2011, pp. 9, 40.

MP to BQ and WP 11kV feeders

CitiPower completed a regulatory test relating to new 11kV feeders at the BQ and WP zone substations in July 2014.[38]

The new feeders from BQ to MP and WP to MP are both required to relieve the emerging N-1 load at risk at MP, and N-2 on the Flinders Ramsden (**FR**) to MP 66kV sub-transmission cables. These feeders are required as part of the overall network development scenario to enable the CBD security of supply upgrade plan works to be completed. This project has a planned commissioning date of November 2017.

4.5.2 Large projects

Not all large augmentation projects have completed the RIT-D process. This section discusses those projects that cost more than $5 million but where a RIT-D will not be undertaken as the project falls within the exceptions set out in clause 5.17.3 of the Rules, or where a RIT-D has not being completed.

Table 4.7 Network service material projects

Project name	Drivers	Cost ($ million, 2015)	Proposed RIT-D start date	Material project no.
WMTS 22kV decommissioning	Replacement	29.7	N/A	AUG 10
Establish WP zone substation	Replacement	See AUG 11	N/A	See AUG 11
NR reactors	Fault levels	4.0	Commenced	AUG 12

Source: CitiPower
Note: direct costs excluding real escalation

Replacement of the 22kV sub-transmission network associated with WMTS was discussed above. The remaining projects are described below.

Establish Waratah Place zone substation

CitiPower intends to build a new zone substation in WP, located in the Chinatown district of the Melbourne CBD. It will replace the existing switching station, known as W.

Elements of the new zone substation are required as part of the Melbourne CBD security program which seeks to increase resilience into the 66kV sub-transmission network given the critical nature of reliable electricity supply to the area.

The new zone substation is required to transfer load away from the decommissioned 22kV Russell Place (**RP**) zone substation which currently has ageing assets, with transformer HI scores of 7.22, 6.93 and 5.34, and a 6.6kV switchboard HI score of 5.34.

Other benefits of the zone substation are to reduce load at MP and Celestial Avenue (**WA**), and reduce load such that there is adequate capacity to sustain two outages on the FR to MP 66kV sub-transmission lines.

[38] CitiPower, *CBD Security of Supply Upgrade Plan: MP to BQ & WP 11kV feeders Regulatory Test Report*, 22 July 2014.

The planned commissioning date for the WP zone substation is November 2017. As these works are driven by the replacement of RP, and that augmentation is incidental, CitiPower has not undertaken a RIT-D.

Reactors at North Richmond zone substation

The North Richmond (**NR**) zone substation has a summer N-1 rating of 56.1 MVA comprised of two 23/28 MVA transformers and one 20/27 MVA transformer operating at 66/11 kV. Due to the lower than normal impedance of two of the three transformers at NR, one of the NR transformers is on hot standby with the 11 kV transformer circuit breaker opened.

The combination of load customers and distributed generation connected to NR has resulted in high fault levels. By 2017, CitiPower estimates the prospective fault current may exceed the allowable limits, even with one transformer on hot standby.

In December 2014, CitiPower made a determination under clause 5.17.4(c) of the Rules that there will not be a non-network option that is a potential credible option, or that forms a significant part of a credible option, for the RIT-D project to address the identified need at NR zone substation.[39]

CitiPower's preferred option is to install a new 66kV reactor, two 11kV reactors, one capacitor bank and a new 11kV bus. This combination of works will enable future embedded generation connections, access the existing capacity of all three transformers, create additional feeder positions to connect new load, and defer the need to replace the existing transformers. This works are expected to be completed by 2017.

4.6 Augex model

In assessing augmentation expenditure forecasts, the AER indicates in its *Expenditure Forecast Assessment Guidelines* that it will use several tools to review each distributor's forecasts:[40]

- assess a distributor's forecasting approach, by assessing the processes, documentation and models used to derive components of the forecast;
- perform detailed reviews of a sample of projects, with assistance from technical and other consultations, paying particular attention to the extent that non-network solutions were considered;
- infer the finding of those reviews to the rest of the augmentation expenditure population;
- undertake individual project cost analysis, by using average cost benchmarking from a database of costs and volumes from major augmentation projects; and
- apply the 'augex' model, which uses information on capacity, utilisation and demand patterns in network segments, and unit costs to produce an alternative forecast.

The augex model is a new tool that Nuttall Consulting has developed for the AER, and it has not yet been applied in regulatory determinations. The AER has previously attempted to assess augmentation using modelling, where Nuttall Consulting determined an average weighted probability of forecast augmentation and applied that to the distributor's forecast in the 2010 draft

[39] CitiPower, *Notice of Determination under clause 5.17.4(c) of the National Electricity Rules North Richmond (NR) Zone Substation 2015–2017*, December 2014.

[40] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, pp. 167-168.

determination.[41] However, the AER decided not to rely upon that tool in the final determination, noting that:[42]

> *…the AER agrees in principle that the weighted average probability assessment recommended by Nuttall Consulting is a credible and valid methodology. However, the AER acknowledges that this methodology requires further testing in order to be used to reliably determine what the total forecast reinforcement capital expenditure that would reasonably reflect the capital expenditure criteria over the forthcoming regulatory control period. For these reasons, the AER has decided not to apply this methodology to determine the total reinforcement capex in this final decision.*

The AER's concerns about the ability of the forecasting tool to provide forecasts that achieve the capital expenditure criteria remain valid and must be demonstrated if it is to rely upon the augex model. This is because:

- Nuttall Consulting noted that augex model is a 'Regulatory tool **NOT** planning/management tool';[43]
- the AER indicates that it may use the model in a deterministic manner, noting in the *Expenditure Forecast Assessment Guidelines* that:[44]

  > *We do not intend to use the augex model as the sole reference point to deterministically set the augex component of a DNSP's capex forecast. …However, this does not preclude us from substituting some or all of the forecasts from the augex model for some or all of the augex components of a NSP's capex forecast.*

- the capital expenditure criteria in clause 6.5.7 of the Rules requires the AER to accept the forecast of required capital expenditure if it reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives. This includes the requirement to meet or manage the expected demand, and well as the quality, reliability or security of supply for standard control services.

CitiPower is therefore concerned about the juxtaposition of the uses of the augex model to forecast the capital expenditure necessary to meet expected demand but not being appropriate to be used as a planning tool.

4.6.1 Overview of the augex model

The AER's aim of the augex model is to 'simplify the analysis of complex forecasting methods while still maintaining some ability at the aggregate level to allow for the main drivers of augmentation'.[45]

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41 AER, *Victorian electricity distribution network service providers distribution determination 2011-2015*, draft decision, June 2010, p. 316.

42 AER, *Victorian electricity distribution network service providers distribution determination 2011-2015,* final decision, October 2010, Appendix P, p. 522.

43 AER, AER expenditure workshop no.4 slides – DNSP replacement and augmentation capex – 8 March 2013, available from https://www.aer.gov.au/node/19508.

44 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, p. 169.

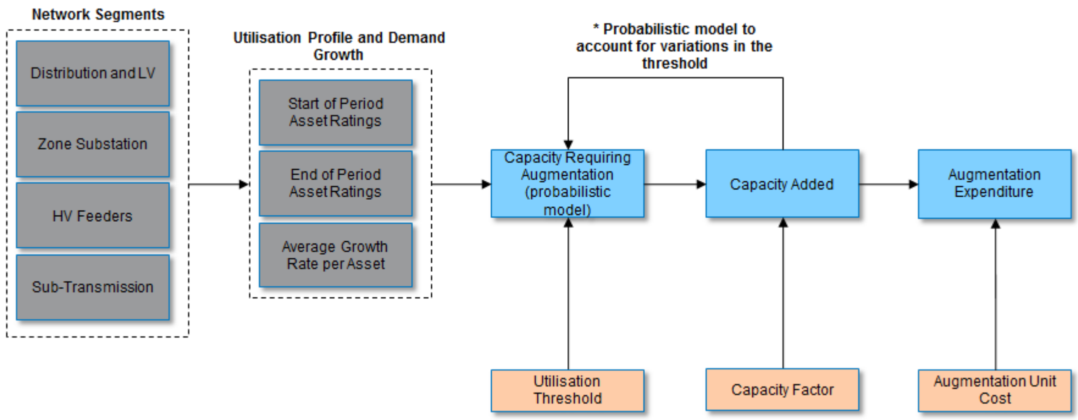
45 AER, *AER augmentation model handbook*, Guidance document, November 2013, p. 14.

The augex model only models demand-driven network capital expenditure. The model determines whether an asset needs augmentation based on the utilisation of the asset. When the peak demand of the asset reaches a certain proportion of its capacity, then it triggers augmentation.

The thermal rating of an asset is used as the basis for its capacity. The asset utilisation at a point in time reflects the proportion of a limit being used at that time i.e. the demand/ thermal rating.

An overview of the model is provided in figure 4.13.

Figure 4.13 Overview of the AER's augex model



Source: CitiPower

The model uses three planning parameters to prepare forecasts, in particular:

- utilisation threshold — defines the point, on average, when assets need to be augmented, i.e. they will breach reliability standards or exceed the economic point of maximum utilisation;
- capacity factor — the amount of capacity that needs to be added to an asset for each unit that is found to require augmentation; and
- augmentation unit cost — represents the average cost for providing an additional unit of capacity to the network.

The model uses four assets classes, namely, zone substations, sub-transmission lines, HV feeders, and LV feeders and distribution substations. Assets can be further divided into sub-categories, such as grounding by the primary type of areas served, or by the length of the lines. Different planning parameters are applied to each of these asset categories and subcategories.

Using the above information, the model simulates year-by-year forecasts of network augmentation over a 20 year period. The simulation uses an augmentation algorithm that contains the following three elements:

- capacity requiring augmentation — assuming a normal distribution for the utilisation threshold, defines the proportion of assets that will need to augmentation as the utilisation increases in the future, taking into account the demand growth rate;
- capacity added — the model multiplies the capacity requiring augmentation by the capacity factor parameter, however the model also considers whether this augmented capacity will also require augmentation later in the simulation period by feeding it back through the step above; and

- expenditure forecast — calculated as the total capacity added in the year by the augmentation unit costs.

4.6.2 Limitations of the augex model

The augex model attempts to simplify the analysis of a range of complex forecasting methods to predict augmentation expenditure for a given distributor. Essentially, the model assumes a distribution network with rigid, deterministic planning criteria, and predicable augmentation methods. In reality, there are ranges of different ways in which distributors plan and operate their networks. The simplifications in the augex model necessarily lead to a reduction in accuracy of the planning outcomes that would be expected from a distributor.

In summary, the augex model includes the following limitations:

- the model is very sensitive to small changes in parameters;
- sub-categories of assets may have small sample sizes, which can impact the accuracy of parameters;
- larger projects for some asset classes can have significant variability in scope, project costs and amount of capacity added to the network, resulting in historical data that is not appropriate for forecasting purposes; and
- history may not be a good predictor for the future.

These matters are discussed in turn below.

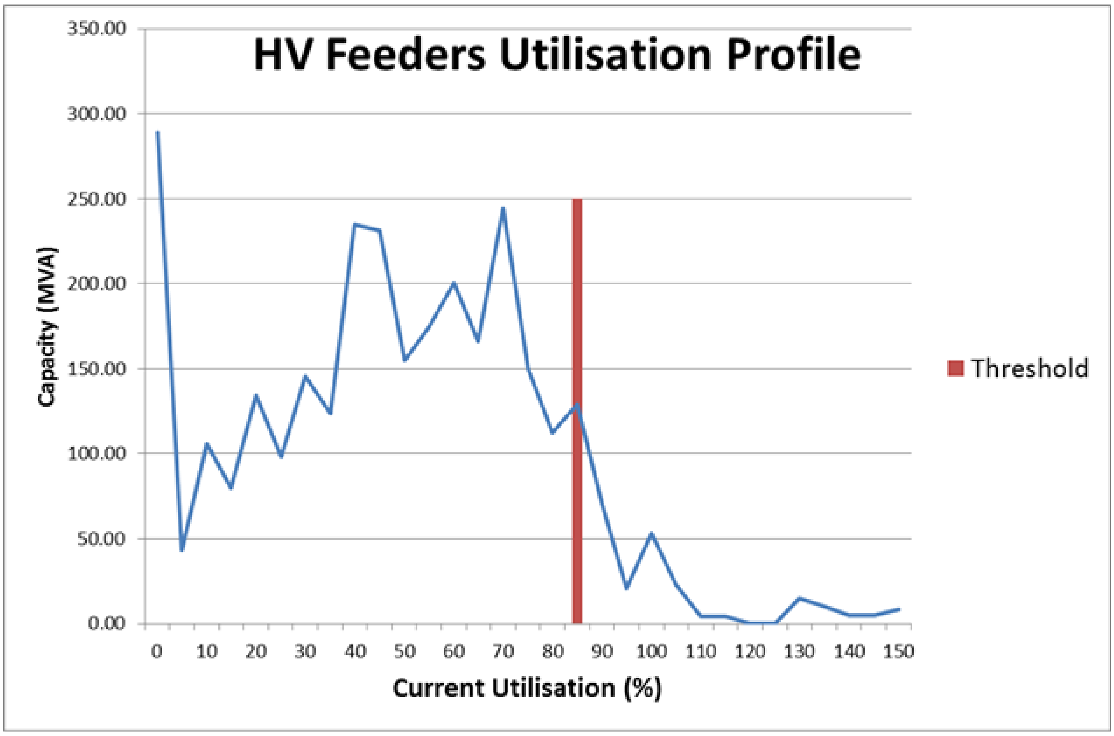
The model is very sensitive to small changes in parameters

The model is quite sensitive to small changes in the utilisation threshold and utilisation standard deviation.

For a given asset, there will typically be a large amount of capacity not too far below the augmentation point. In this case, a threshold a little too low will augment far too much capacity, while if it is set a little too high the forecasts get delayed rapidly.

Take for example the utilisation profile for CitiPower’s HV feeders, shown in figure 4.14.

Figure 4.14 Utilisation profile for HV feeders



Source: Jacobs, *CitiPower AER Augex modelling assistance*, 25 November 2014, p. 10.

Figure 4.14 shows that the threshold for utilisation is approximately 85 per cent, based on historical data. The bulk of assets are a little below the threshold, with some capacity near the augmentation point, and a few assets overloaded. The assets with high utilisations will have individual reasons why they haven't been augmented yet – with augmentation likely to occur in the next few years.

The augex model is also sensitive to the utilisation threshold standard deviation. Figure 4.14 shows that some of the highest utilised assets are about as far above the threshold as the bulk of the assets are below it. The 'standard deviation' parameter controls for this effect, as capacity is not augmented all at once when it hits the threshold, but gets spread out over a few years. However, the augex model assumes a normal distribution, with augmentation equally as likely above and below the threshold point.

Therefore, if the augex model uses a low standard deviation, it will immediately augment everything that is highly utilised, while if the deviation is set too high, the augex model will consider assets substantially below the threshold as potentially in need of augmentation.

Getting sensible input parameters is challenging with a small number of samples

The model is also sensitive to forecast planning parameters, particularly the Capacity Factor. The Capacity Factor represents the response of the distributor to highly loaded assets, and is typically based on historic data. However, especially in the case of sub-transmission and zone substation asset classes, there are typically only a few historic projects from which to derive this forecast planning parameter.

The small sample sizes mean that the results may not be statistically representative of the actual results. This will lead to inaccuracies in the modelled outputs.

Variability in scope of historical projects

Larger projects of these asset classes can have significant variability in project scope, costs, and amount of capacity added to the network.

For example, there are many potential drivers for augmentation of the sub-transmission network, including constraints at a zone substation or on feeders. Solutions to overcome the capacity constraints are therefore unique to the location of the constraint and the network configuration. The number of constraints and associated augmentation projects at this level of the network is generally small, and as such there is no 'average' sub-transmission project.

This has been observed by Jacobs in reviewing the augex model inputs for CitiPower. In its report, Jacobs observed that planned network augmentations over the 2016-2020 period involves construction of new substation assets, whereas such projects were not observed in the previous regulatory period.[46]

Jacobs noted that forecast planning parameters derived from the smaller numbers of samples, or from periods where program of works were different from current planning, tend to produce inconsistent forecasts.[47] That is, the augex model outputs would be significantly at variance with the actual expenditure requirements.

History may not be a good predictor of the future

The drivers of network augmentation are often outside of the control of the distributor. The augex model appears to assume that the past is a good predictor of the future, which implicitly assumes that the distributor has implemented an optimal augmentation strategy.

The augex model fails to account for changes in circumstances. For example, a network may have invested in overhead networks in the past but may need to invest in the more costly underground networks going forward. As a result, the augex model may underforecast required expenditure.

4.6.3 Populating the augex model

Jacobs assisted CitiPower in populating the augex model. It has prepared a report which outlines the steps that were undertaken in the model population, as well as addressing the matters set out in paragraphs 7.2(a) and 7.2(d) of the RIN.[48]

At a high level, Jacobs has undertaken the following four steps in populating the input data for the augex model:

- configured the asset class groupings into categories and sub-categories, and avoiding detailed sub-categorisation or subgrouping as advised by the AER's augmentation model handbook;
- determined a 'base case' by establishing the value of the Utilisation Threshold Mean by observing the graphical pattern of the asset utilisation, and the capacity factor was derived from the available completed project data. Other input parameters were determined by either referring to the populated Reset RIN Tables corresponding to the respective asset class, or by referring the historical or/and planned demand driven project information, project cost, and estimation data;

46 Jacobs, *CitiPower AER Augex modelling assistance*, 25 November 2014, pp. 10-11.

47 Jacobs, *CitiPower AER Augex modelling assistance*, 25 November 2014, p. 11.

48 Jacobs, *CitiPower AER Augex modelling assistance*, 25 November 2014.

- modelled the capacity added after identifying input parameters that produced plausible capacity forecast; and
- modelled the cost forecast by using average unit costs from project cost data in a particular asset class.

Addressing the change in forecast work in the augex model

For sub-transmission lines, Jacobs observed that historical projects were not demand driven. In contrast, CitiPower's planned and committed construction in the 2016-2020 period involves demand driven augmentation. Therefore, Jacobs has derived the Capacity Factor from planned demand driven project data.

Source: Jacobs, *CitiPower AER Augex modelling assistance*, 25 November 2014, p.15.

The input parameters that Jacobs have used in its augex modelling are shown in table 4.8.

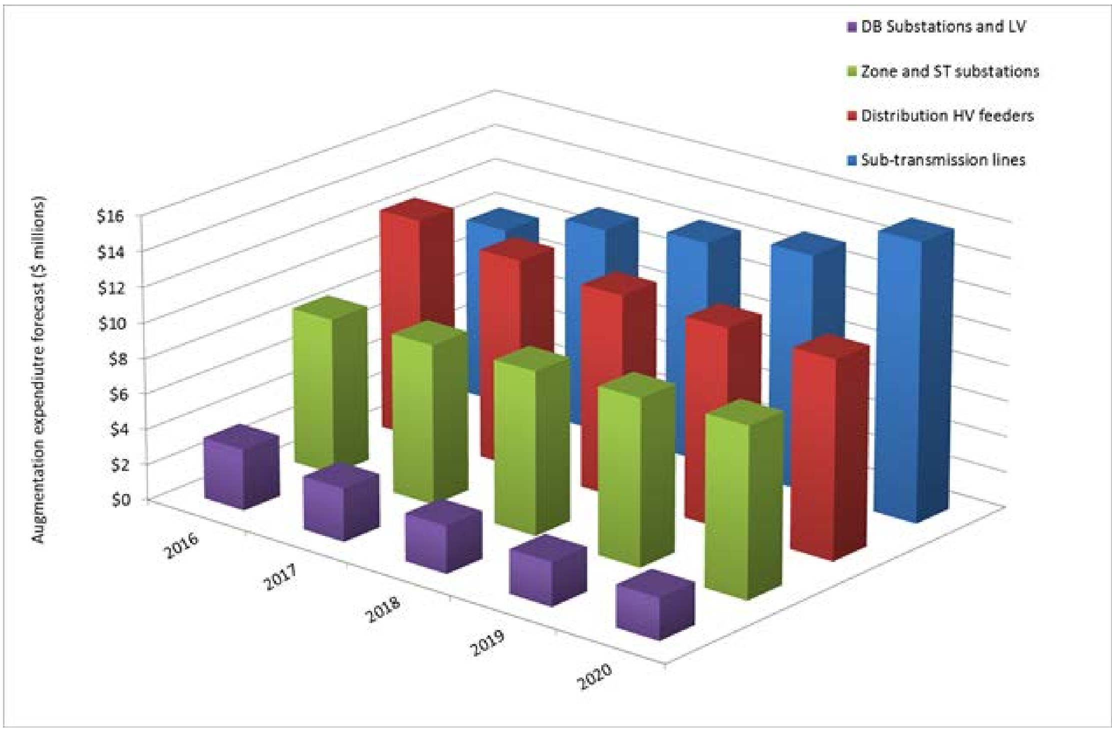
Table 4.8 Input values for AER augex model

Network segment title		AER segment group	Forecast planning parameters				
Asset class	Asset categories/ subcategories		000' $/MVA	Cap Factor	UT Mean	UT σ	Max Demand
Sub-transmission lines	<0% growth	1	$142.44	0.38	127.57%	9.0%	0.00%
	0 – 3% growth	1	$142.44	0.38	124.86%	9.0%	1.84%
	3 – 5% growth	1	$142.44	0.38	123.84%	9.0%	3.90%
	>5% growth	1	$142.44	0.38	126.46%	9.0%	7.26%
HV feeders	HV Feeder 0%-2% growth CBD	4	$196.95	0.75	100.0%	12.9%	0.79%
	HV Feeder 2%-4.5% growth CBD	4	$196.95	0.75	100.0%	12.9%	2.64%
	HV Feeder >4.5% growth CBD	4	$196.95	0.75	100.0%	12.9%	4.92%
	HV Feeder 0%-2% growth URB	5	$158.54	0.64	67.0%	12.9%	1.06%
	HV Feeder 2% - 4.5% growth URB	5	$158.54	0.64	67.0%	12.9%	3.07%
	HV Feeder >4.5% growth URB	5	$158.54	0.64	67.0%	12.9%	4.92%
Zone substation	CBD	3	$194.73	0.57	73.1%	28.5%	1.85%
	Urban	3	$194.73	0.57	62.3%	28.5%	1.68%
Distribution transformers and LV feeders	NA	8,9	$150.11	2.27	127.1%	10.7%	1.64%

Source: Jacobs, *CitiPower AER Augex modelling assistance*, 25 November 2014, p. 21.

Given the input parameters, the output of the augex model in terms of annual augmentation expenditure is shown in figure 4.15.

Figure 4.15 CitiPower's augex model forecast output summary – annual expenditure



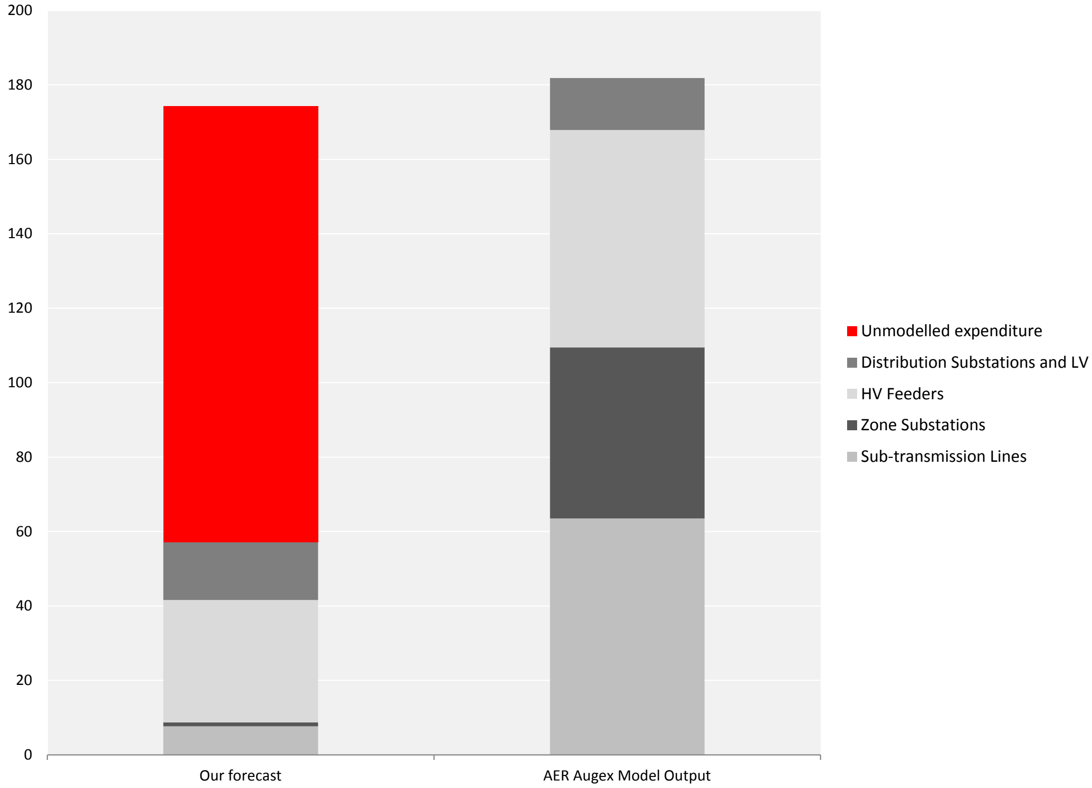
Source: Jacobs, *CitiPower AER Augex Modelling Assistance*, 25 November 2014, p. 6.

4.6.4 Reconciliation

CitiPower has not used the AER's augex model as the primary basis for forecasting augmentation expenditure, rather it has used the methodology outlined in section 4.2.3 to establish its forecast for augmentation expenditure.

The augex model forecasts a higher level of expenditure required for augmentation related works compared to CitiPower's forecasts, as shown in figure 4.16.

Figure 4.16 Comparison of CitiPower's forecast to augex model forecast output ($million, 2015)



Source: CitiPower
Note: direct costs excluding real escalation

CitiPower estimates that 33 per cent of its augmentation expenditure is covered by the drivers in the AER's augex model.

The AER's augmentation model handbook identifies instances that the augex model does not cover, including:[49]

- fault level mitigation works, which by their nature are not directly related to the peak loading of assets;
- augmentation to manage low demand situations; and
- augmentations driven largely by the connection of generation and the ability of the network to export the supply from the generation.

In addition to the above, CitiPower notes that the augex model does not cover:

- augmentation of distribution assets driven by transmission connection asset constraints;
- augmentation to deliver security of supply;
- augmentations to address supply quality (i.e. voltage compliance that is unrelated to peak demand); and

49 AER, *AER augmentation model handbook*, Guidance document, November 2013, p. 33.

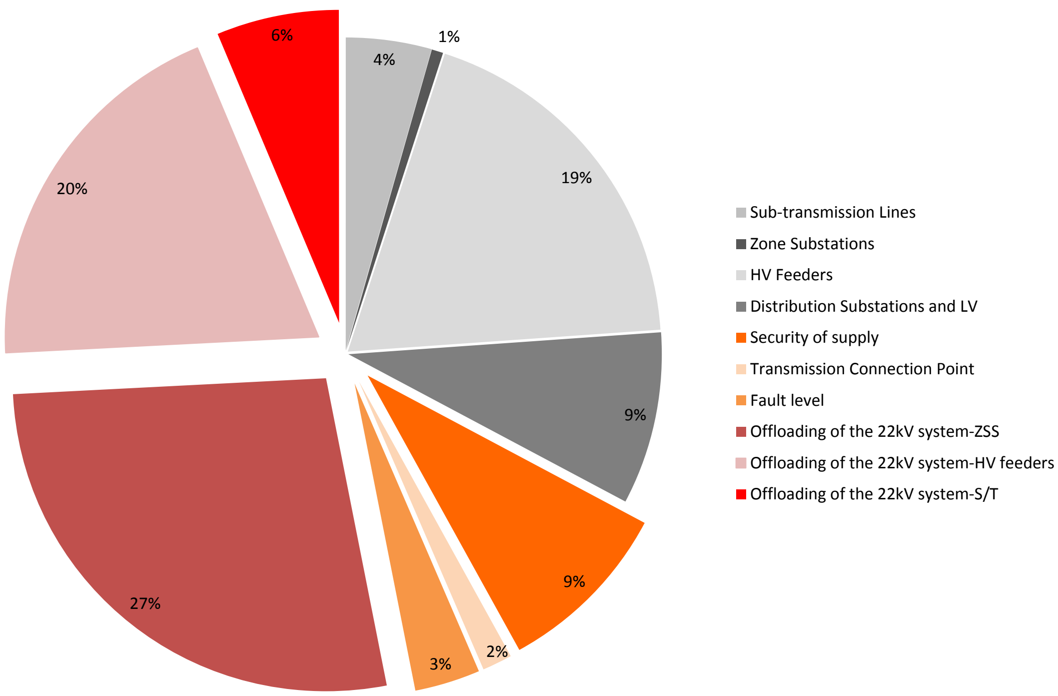
- ancillary costs associated with large augmentation projects, such as secondary control and protection equipment.

For CitiPower, the remaining 66 per cent of its augmentation expenditure that is not covered by the augex model relates to:

- non-demand related augmentation works related to the decommissioning of the 22kV sub-transmission network;
- security of supply related works, including the CBD Security of Supply upgrade plan in accordance with the Victorian Electricity Distribution Code;
- fault level mitigation works; and
- distribution works resulting from the need to address transmission connection point constraints at Richmond and West Melbourne terminal stations.[50]

This is shown in figure 4.17.

Figure 4.17 Augmentation expenditure not captured by augex model



Source: CitiPower

The replacement-driven works that will result in augmentation of the network have been discussed earlier in this chapter.

50 Refer to NERA, *Proposed Augmentation for Melbourne Inner Suburbs and CBD Supply, A Final Report prepared for CitiPower and AEMO*, May 2011.

The augex model also does not capture the costs of works to provide new 66kV cables to connect to the upgraded 66kV connection point at BTS, as these cables arise from constraints at the terminal station level. The augex model does not capture utilisation and demand at the terminal station level.

Additionally, the security of supply works relating to the CBD Security of Supply Upgrade Plan are not captured by the augex model. These works may result in an increase in service levels for a similar customer demand level.

Finally, fault level mitigation works are excluded from the augex model, as the model is not designed to cover current and forecast fault levels, only current and forecast peak demand utilisation. CitiPower will be installing new reactors at the North Richmond (**NR**) zone substation and installing a circuit breaker ‘normal open – auto close’ control scheme at Albert Park (**AP**) zone substation, to manage fault current levels that are approaching the allowable limits as a result of increasing levels of embedded generation

4.7 Synergies between augmentation and replacement

CitiPower is able to use both the load indices and health indices at zone substations to obtain an overall picture of the current load and condition of the zone substation transformers, and how this is expected to change overtime.

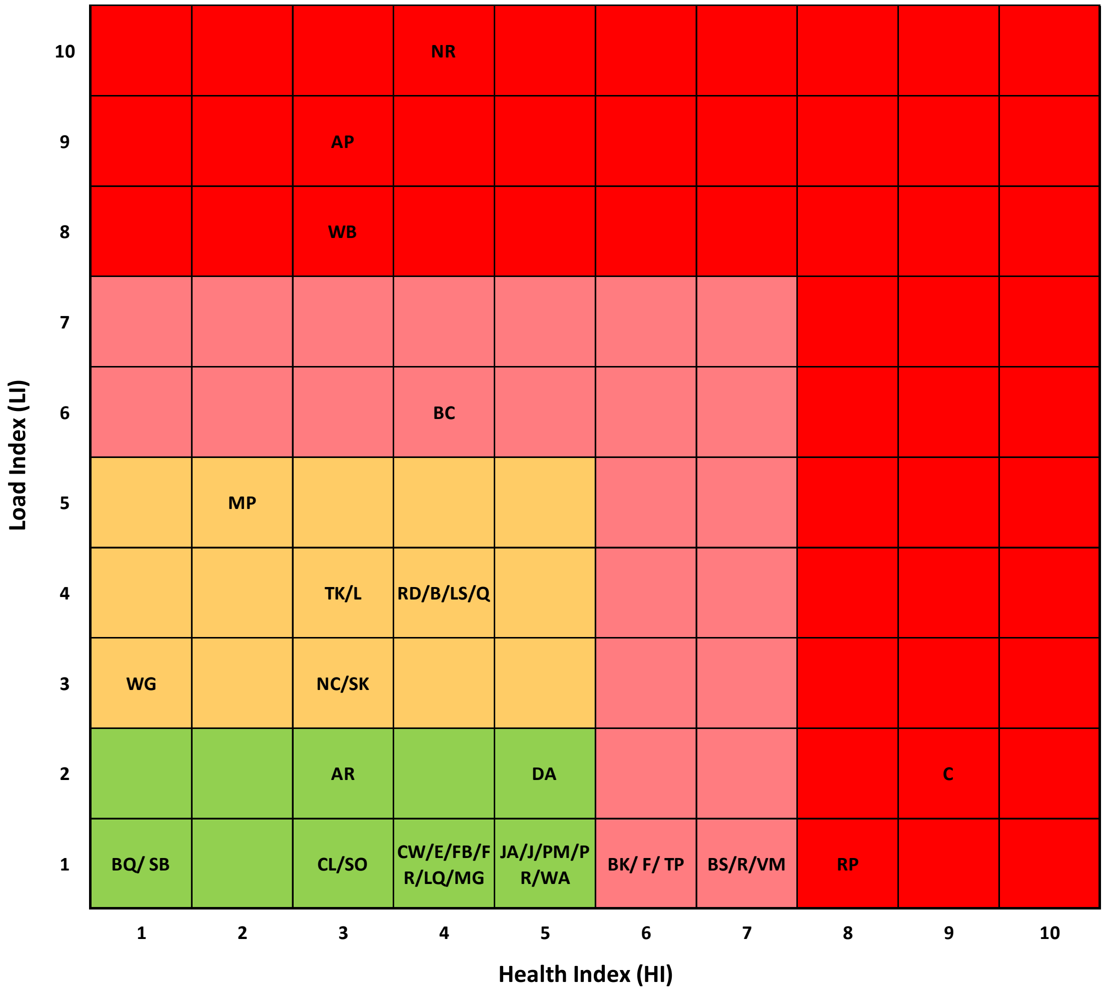
A matrix can show which zone substations have transformers that:

- have large amounts of energy at risk in peak times, and may require augmentation, with a high load index;
- are in poor health and in need of replacement, with a high HI; and
- have large amounts of energy at risk at peak times and are in poor health, with high load and health indices, where the transformers are in need of replacement with a higher capacity transformers.

The overall picture can highlight project synergies. For example, if a particular zone substation has a high load index and transformers with a poor HI, an augmentation project to replace the transformers with higher capacity units will reduce both the load related and health related index measures.

The matrix in figure 4.18 shows the load and health indices for each zone substation that is expected at the start of the 2016–2020 regulatory control period. This takes into account expected works during the 2015 calendar year.

Figure 4.18 Load and health indices at zone substations at start of 2016

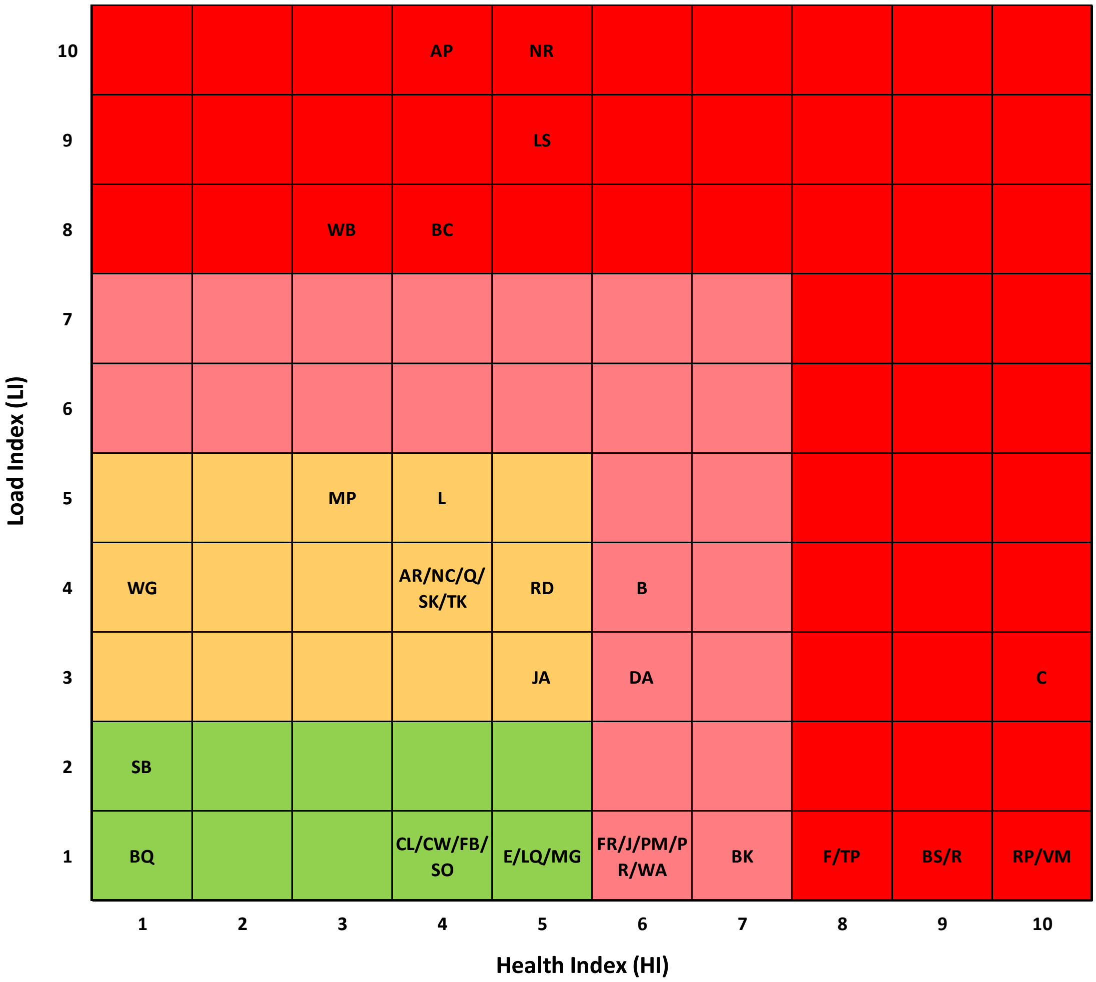


Source: CitiPower

As can be seen, CitiPower has high load indices at North Richmond (**NR**), Albert Park (**AP**) and West Brunswick (**WB**) zone substations. CitiPower also has high health indices at the Brunswick (**C**), Russell Place (**RP**), Bouverie Street (**BS**), Richmond (**R**), and Victoria Market (**VM**) zone substations.

If CitiPower does not invest in augmentation and replacement works over the 2016–2020 regulatory control period, i.e. 'do nothing', then an increasing number of zone substations will have load and health indices as shown in the matrix (figure 4.19) below.

Figure 4.19 Load and health indices at zone substations at the end of 2020 in the 'do nothing' scenario

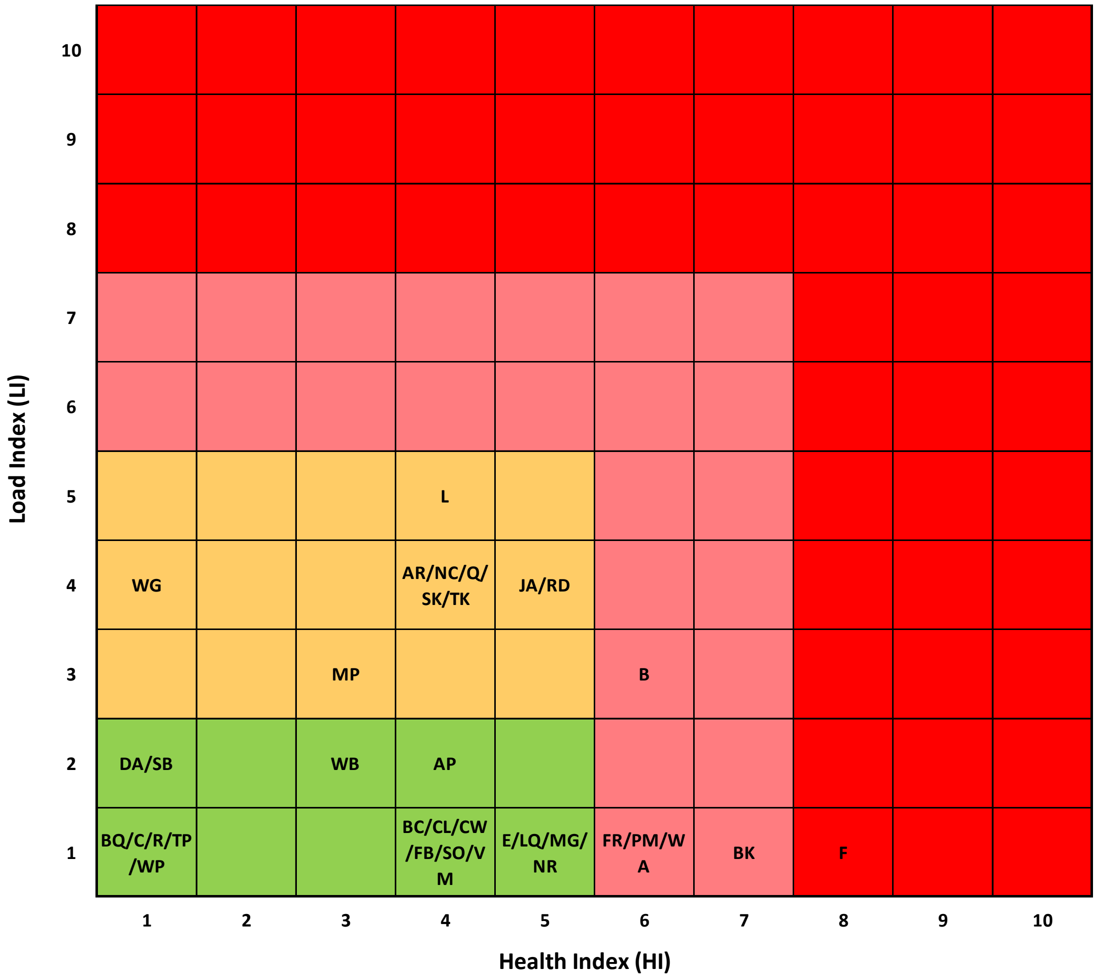


Source: CitiPower

If CitiPower does not invest, then five zone substations will have high load indices and eight zone substations will have high health indices including Brunswick (**C**), Bouverie St (**BS**), Richmond (**R**), Fitzroy (**F**), Tavistock Place (**TP**) and Brunswick (**BK**) which are all connected to the 22kV sub-transmission network. It is clear that if CitiPower does not invest, then its customers would experience a vast increase in the number of outages as the assets become overloaded and/or fail due to poor condition.

The matrix below shows the load and health indices for the zone substations given the expenditure contained with this regulatory proposal.

Figure 4.20 Load and health indices at zone substations at the end of 2020 with proposed expenditure



Source: CitiPower

This matrix demonstrates that CitiPower's proposed expenditure will address zone substations with high health and load indices. For example, the 22kV decommissioning program and the completion of the CBD Security Program will address the concerns at the BS, C, TP, LS and RP zone substations.

The fault mitigation projects at AP and NR will also address the very high load index levels at these zone substations.

5 Connections and customer driven works

When customers seek to connect to the network, or change their existing connection, then CitiPower needs to meet its customers' requirements.

The forecast expenditure will enable CitiPower to connect customers to its network, including to supply new residential customers, assist industrial customers in expanding their operations, and to support connection of renewable energy generators.

A significant portion of this expenditure will be directly recovered from the connecting customer via a customer contribution.

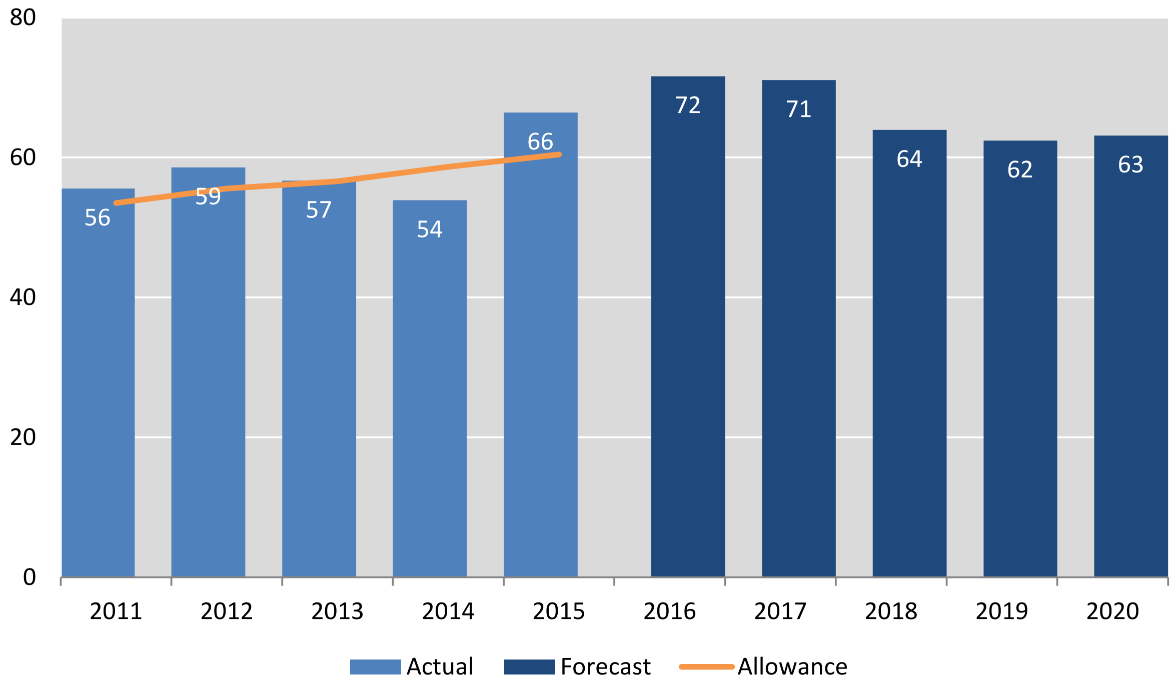
This section discusses CitiPower's historical and forecast connection and customer driver works expenditure as well as its approach to calculating the expenditure.

5.1 Overview

Connections and customer driven works relates to expenditure to connect residential, commercial and industrial customers to the distribution network, connections for embedded generators and customer requested relocations (i.e. recoverable works).

An overview of historical and forecast gross capital expenditure is shown in figure 5.1. However, CitiPower will receive funding directly from some customers towards their connection.

Figure 5.1 Gross connections direct capital expenditure ($ million, 2015) [51]



Source: CitiPower

[51] 2011 to 2014 are actual costs, 2015 to 2020 are forecast costs.

The profile shows that expenditure was fairly consistent during the period from 2011–2014, with a step up in 2015 and 2016 and then it is forecast to remain fairly consistent from 2017 to 2020. The step-up is driven by specific urban renewal projects.

In focus groups undertaken through CitiPower's stakeholder engagement program, very few residential customers had required new connections, but those that had indicated a general satisfaction and ease of dealing with CitiPower.[52] For small and medium enterprise customers, a small minority in the focus groups had recently experienced new connections and those that had indicated that they were highly satisfied with the management and communication of new connections. Through these focus groups, improvements to the management of connections were not viewed as necessary.[53]

In relation to new connections, CitiPower's large customers generally had five core expectations:[54]

- transparency in process – ensuring the process is well considered, transparent and in the best interests of the customer (with regular updates provided);
- work to exact timeframes – ensuring realistic and efficient timeframes, with commitment and guarantees that timelines will be met;
- flexibility and empathy – ensuring large customers are treated individually, with recognition that their large financial outlay and investment in electricity is valued and carries with it higher levels of flexibility, attention and responsiveness;
- reliability and dependability – ensuring that CitiPower is there for large customers when needed; and
- support growth – ensuring that CitiPower acts as a genuine business partner, supporting new venue/new site related planning/electricity requirements and also investing in infrastructure to minimise reliance on a single substation. Also to work with knowledge sharing/exchange.

Customer connections will continue to be an important area for CitiPower into the future. A particular focus is embedded generators connect to the network where they want back-up power or to sell their excess electricity to the market.

5.2 Background

This section describes CitiPower's methodology for forecasting connections and customer-driven works capital expenditure.

5.2.1 Key drivers for expenditure

The connections and customer-driven works category involves expenditure that is driven by customers, rather than being initiated by CitiPower. The expenditure is influenced by economic conditions and development demographics, including major projects arising from government initiatives, commercial developments, embedded generation, changes in industrial and agricultural sectors and housing developments.

52 Colmar Brunton Research, *CitiPower Stakeholder Engagement Research Report – Residential Customer Focus Groups and SME Customer Interviews*, 30 April 2014, p. 39.

53 Colmar Brunton Research, *CitiPower Stakeholder Engagement Research Report – Residential Customer Focus Groups and SME Customer Interviews*, 30 April 2014, p. 39.

54 Colmar Brunton Research, *CitiPower stakeholder engagement research top 200 customers in-depth interviews*, 22 July 2014, p. 30.

Connections and customer-initiated works expenditure is distinguished from augmentation capital expenditure based on the driver of the expenditure. For example, the load associated with a new customer connection is expected to cause a capacity constraint on a sub-transmission line, the costs to augment the line will be allocated to the connections and customer-driven works expenditure category.

As an exception, where a customer connects embedded generation to the network, and the connection requires augmentation of the network beyond the first point of transformation, referred to as 'deep' augmentation, then the deep augmentation costs are captured in the augmentation category.

Aside from augmentation, CitiPower does not consider that there is any reasonable scope for ambiguity between connections and customer-initiated works and any other category expenditure category.

5.2.2 Customer connection process

CitiPower has different connection processes for customer connections depending on whether:

- the supply of electricity is already available to the property; or
- the applicant is seeking to connect for the purposes of receiving electricity and/or exporting electricity on to the grid.

The customer connection process is set out in *CitiPower's customer guideline for making an electricity supply available and undergrounding of existing assets*.[55]

The majority of residential connections are routine connections where CitiPower can remotely connect the customer at the request of a retailer.

Where an overhead line, underground cable, substation, or embedded generator needs to be extended or upgraded to service new or upgraded customers, then the customer must submit an application to CitiPower, which sets out the location of the premises and an estimate of the amount of electricity required. In response, CitiPower will provide a budget estimate or firm offer to the customer, where the customer may also have the option to select other recognised contractors to complete works for contestable services.

The customer may be liable to pay a customer contribution towards the connection, where the contribution is calculated in accordance with *Electricity Industry Guideline No. Electricity Industry Guidelines 14 – Provision of Services by Electricity Distributors (*__Guideline 14__).

[55] Available from: https://www.citipower.com.au/media/1433/citipower-customer-guideline-07-dec-2010.pdf.

Calculation of customer contributions

Under the *Electricity Industry Guideline No. 14,* customer contributions are calculated according to the following calculation:

CC=[IC – IR] + SF

Where:

CC is the maximum amount of the customer's capital contribution;

IC is the amount of incremental cost in relation to the connection offer;

IR is the amount of incremental revenue in relation to the connection offer; and

SF is the amount of any security fee.

Incremental Cost (IC) is the cost of the project works including new incremental capital, operating maintenance and the costs of any works that CitiPower will incur in making the supply available to the nominated point of supply. The Incremental Cost excludes the Connection Service Fees and transmission costs.

If the applicant chooses to run their own tender and use a Recognised Contractor other than CitiPower to complete any Contestable Services, the applicant is required to provide CitiPower with evidence detailing the total cost of these tasks. CitiPower will compare those costs against the average cost for equivalent work completed on its lines, when calculating any Incremental Cost.

Incremental Revenue (IR) is the revenue that CitiPower will receive from the new connection via the distribution tariffs. Revenue is allowed at 15 years for a business connection and 30 years for a domestic connection, in accordance with the guidelines.

The value of the Customer Contribution also depends on the amount of electricity that the customer agrees to use. The amount of electricity consumption that the customer requires is used to calculate your Incremental Revenue.

Security Fee (SF) is like a bond. It is the amount held by CitiPower and returned with interest, should the applicant achieve the agreed electrical revenue consumption targets.

Where the customer is seeking to connect an embedded generator onto the grid, then CitiPower has two different processes for connections:

- where the connection is in accordance with Australian Standard 4777, then the customer must seek pre-approval for the connection; and
- all other connections are in accordance with the Guideline 14 or *Electricity Industry Guideline 15-Connection of Embedded Generators* (**Guideline 15**)*,* or Chapter 5.3A of the Rules if the customer elects to follow the process.

CitiPower is supportive of small solar generation that can be interconnected with its network. However, the pre-approval process allows CitiPower to identify concentrations of solar PV systems on the low voltage network which can lead to potentially non-compliant power quality issues such as overvoltage and voltage unbalance.

Customer contributions for embedded generation are calculated in accordance with Guideline 15. Under these guidelines, embedded generators do not make any contributions for 'deep' augmentation but may contribute to 'shallow' augmentation, i.e. extension assets between generating plant and point of connection to the distribution network, and relevant connection assets required by the distributor.[56]

National Energy Customer Framework (NECF)

The NECF consists of a new National Energy Retail Law which would be applied in Victoria together with a range of Rules made by the AEMC, and would replace significant parts of the current State energy laws. It involves the transfer of Victorian responsibilities to a new national regulatory regime governing the sale and supply of energy to retail customers, including new connections to distribution networks.

For Victorian distribution businesses, the largest implication of adopting NECF would be that:

- Guidelines 14 and 15 fall away; and
- Chapter 5A of the Rules will apply in Victoria.

Pursuant to Chapter 5A of the Rules, the AER has published a *Connection Charge Guideline* which provides a guide to distributors to develop their connection policies.[57]

Should Victoria adopt NECF, or Chapter 5A of the Rules, then CitiPower will be required to develop its connection policy in accordance with the AER guidelines, and then seek approval of the policy from the AER. The connection policy must be consistent with the connection charge principles set out in Chapter 5A of the Rules and the AER guidelines.

CitiPower’s connection policy under Chapter 5A of the Rules would use a different approach from Guidelines 14 and 15 for the calculation of connection charges and customer contributions. The calculation of the connection charges and customer contributions of Chapter 5A is set out in the box below.

[56] Essential Services Commission, *Electricity Industry Guideline No. 15 – Connection of Embedded Generation*, August 2004, clause 3.3.2(b)(1)(B).

[57] AER, *Connection charge guidelines for electricity retail customers —under chapter 5A of the National Electricity Rules*, June 2012.

Calculation of connection charges under chapter 5A connection charge guideline

The connection charge guideline specifies the connection charge cost to the customer is calculated as follows:

Connection Charge = AS + PS + SF + CC

Where:

- **AS** is the charge payable for relevant alternative control services;
- **PS** is contribution to any relevant pioneer scheme. If an dedicated extension ceases within seven years after its construction to be dedicated to a customer, then that customer is entitled to a refund, which may be recovered from new users of the asset;
- **SF** is a security fee which CitiPower charges on high-risk new connections such as mines and drought-prone irrigation. CitiPower refunds 1/5th of the security each year unless the revenue forecasts are not realised;
- **CC** is the capital contribution payable for all relevant standard control services.

The capital contribution payable by the customer included within the calculation is calculated in accordance with the following calculation:

Capital contribution= ICCS + ICSN – IR

where:

- **ICCS** is Incremental Cost Customer Specific;
- **ICSN** is Incremental Cost Shared Network subject to an agreed augmentation threshold, but excluding micro-embedded generators; and
- **IR** is Incremental Revenue which is calculated as the present value of expected distribution revenue over 30 years (residential) or 15 years (non-residential).

5.2.3 Customer contributions

CitiPower's forecasting methodology document outlines that it was unclear at this stage whether it will be required to comply with the AER's *Connection Charge Guideline* issued under Chapter 5A of the Rules[58] or the ESCV's Guidelines 14 and Guideline 15 when determining connection charges, including capital contributions.

CitiPower therefore noted that for the purposes of developing the expenditure forecasts, it would assume the *AER's connection charge guideline* would apply. In addition, CitiPower would assume the current requirement set out in clauses 2.2 and 2.3 of Guideline 14 for distributors to contribute avoided costs to underground, relocate or modify any of a distributor's distribution assets will be preserved over the 2016-2020 regulatory control period.[59]

[58] AER, *Connection charge guidelines for electricity retail customers —under chapter 5A of the National Electricity Rules*, June 2012.

[59] Powercor, *2016-2020 Price Reset –Expenditure Forecasting Methodology*, 30 May 2014, p. 8, 20.

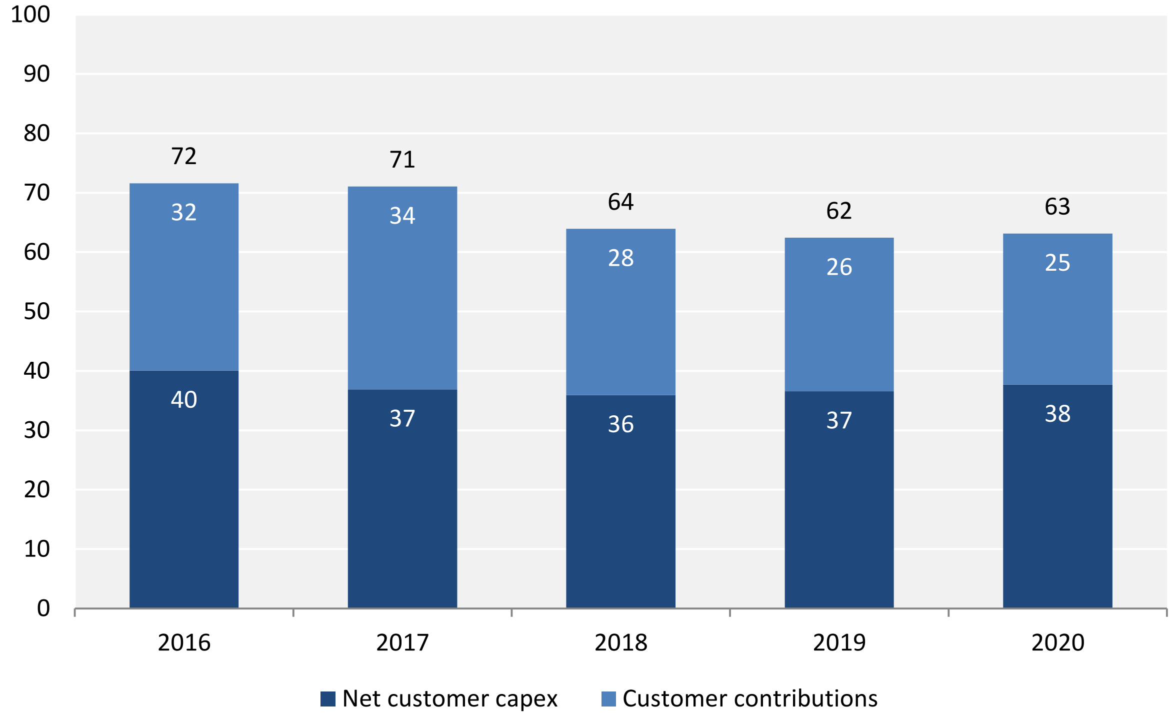
However, in the final Framework and Approach (**F&A**) paper, the AER indicated that it will continue to operate on the basis that Guidelines 14 and 15 will apply in Victoria.[60]

Consequently in calculating the customer contributions for the capital expenditure forecasts, CitiPower has now assumed that Guidelines 14 and 15 will continue to apply. Therefore, in its expenditure forecasts, CitiPower has provided two sets of forecasts to the AER, in particular:

- gross connection costs; and
- net connection costs, where the revenue obtained from customers is netted-off against the costs assuming that Guidelines 14 and 15 are in place.

An overview of the gross and net connection costs, as well as an estimate of customer contributions, is provided in figure 5.2.

Figure 5.2 Customer contributions



Source: CitiPower

Customer contribution forecasts have been calculated by multiplying a calculated contribution rate by the gross connection capital expenditure in each of the internal reporting categories i.e. function code. The contribution rates were calculated by first selecting a representative sample of 2013 customer projects for each connection function code. The sample contains historical information on the average consumption expected by the customer, given the mix of customer types (e.g. apartment, shop, etc). The expected life of the customer is 15 or 30 years, depending on whether or not the customer is a residential customer.

[60] AER, *Final Framework and approach for the Victorian Electricity Distributors—Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 43.

The customer contribution rate for each sample project was re-calculated with changes made to the following inputs:

- total project cost, augmentation rates, incremental operating and maintenance expenditure and tariff rates escalated to 2016;
- the Weighted Average Cost of Capital (**WACC**) and X factors applied in the calculation of the customer contribution were updated using CitiPower's proposed WACC and X factors for the 2016–2020 regulatory control period;
- overhead rate adjusted to reflect that corporate overheads will no longer be applied to capital from 2016; and
- an additional incremental cost item included for incremental corporate income tax cost.

The contribution rate model is provided in the *Customer contribution rate* attachment.

The AER noted that if it can be established in time for the determination that Guidelines 14 and 15 are to be removed and not replaced with new jurisdictional charging provisions, then its intention is to apply the AER's connection charge guideline to the Victorian distributors.[61]

CitiPower has not estimated the change in customer contributions that would result from the introduction of NECF or Chapter 5A of the Rules and calculated in accordance with the AER *Connection Charge Guideline*.

5.2.4 Forecasting methodology

CitiPower has used two different methodologies for forecasting customer connections into the AER's specified categories depending on whether the category of connection has a high or low volume of activity:

- for high volume categories of connections, forecasts of the number of customer connection jobs have been estimated by an external economic consultant using key economic and demographic variables (including growth in population, new dwellings, gross state product, new business, and new non-residential dwellings) to project historical data;
- for low volume categories of connection categories, forecasts of customer connections have been estimated using a bottom-up build of major projects.

A mapping of the applicable AER's sub-categories for standard control connection services to the forecasting methodology is set out in table 5.1.

[61] AER, *Final Framework and approach for the Victorian Electricity Distributors—Regulatory control period commencing 1 January 2016* , 24 October 2014, p. 43.

Table 5.1 Methodologies for forecasting connections expenditure

Sub-category	Classification	Methodology
Residential	Simple connection LV	Economic forecast
	Complex connection LV	
	Complex connection HV	
Commercial/ Industrial	Simple connection LV	Economic forecast
	Complex connection HV – connected at LV, minor HV works	
	Complex connection HV – connected at LV, upstream asset works	
	Complex connection HV (customer connected at HV)	Bottom-up build
	Complex connection sub-transmission	Economic forecast
Subdivision	Complex connection LV	None for CitiPower
	Complex connection HV (no upstream asset works)	
	Complex connection HV (with upstream asset works)	
Embedded generation	Simple connection LV	None for CitiPower
	Complex connection HV (small capacity) (000's)	Bottom-up build
	Complex connection HV (large capacity)	

These methodologies are discussed in more detail below.

High volume categories of connections

From table 5.1, economic forecasts have been prepared for the following categories of connections which are associated with high volumes of activity:

- residential complex connection at LV;
- residential complex HV works connected at LV;
- commercial/industrial HV works connected at LV; and
- subdivision.

CitiPower engaged the Centre for International Economics (**CIE**) to prepare forecasts of customer project connections for the 2015 to 2020 period. CIE prepared a report that provides a detailed description of their methodology, and is attached to the regulatory proposal.[62]

CIE used historical data for the years from 2009 to 2013 from CitiPower's submission to the AER's Category Analysis RIN.

CIE established historical relationships between the historical data and economic and demographic variables for residential, commercial and subdivision categories of connections. Using correlations and econometric modelling, CIE identified that population growth, dwelling growth and economic activity are statistically significant in explaining the number of customer connection projects.

Once the drivers were identified, CIE forecast the number of connection jobs using independent forecast data, in particular:

- for gross state product (**GSP**), CIE used the forecast by the AEMO that predicts that GSP will accelerate over the next few years before easing back towards more normal growth rate by the end of the 2016–2020 regulatory control period; and
- for the number of dwelling approvals, forecasts from the Victorian Department of Transport, Planning and Local Infrastructure which suggest that that the rate of development over the 2010 to 2013 period will continue in 2015 and 2016, before returning to levels more in line with the long term average.[63]

CitiPower mapped the CIE forecasts of jobs per AER connection category to its internal reporting categories, i.e. function codes. These were then multiplied by the unit rate in each function code to obtain the forecast expenditure. The unit rate was calculated by dividing the total expenditure by the total number of jobs in each function code for the period 2011 to 2014.

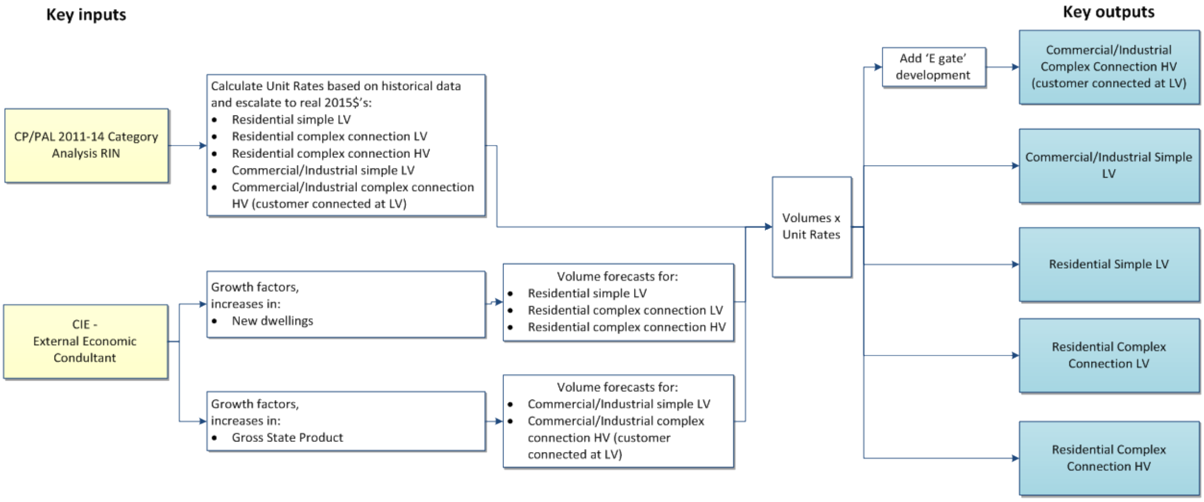
The unit rate therefore reflects historical costs for similar projects where the materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

An overview of the forecasting process for these high-volume connections is shown in figure 5.3.

[62] CIE, *Forecasting connection projects for CitiPower and Powercor*, November 2014.

[63] CIE, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 33.

Figure 5.3 Overview of economic forecast process



Source: CitiPower

Low volume categories of connections

CitiPower has undertaken a bottom-up build of the categories of connections where there are typically low volumes. The bottom-up forecasts have been prepared for the following connection categories:

- commercial/industrial connections connected at HV;
- embedded generation; and
- recoverable works (reported as quoted services).

The preference for using bottom-up build rather than establishing relationships with economic drivers is that the projects are often unrelated to broader activity in the economy and may be driven by government policy or specific customer needs.

To establish the forecasts, CitiPower has broken the forecasting into the following components:

- projects that cost $2.5 million or more; and
- projects that cost less than $2.5 million.

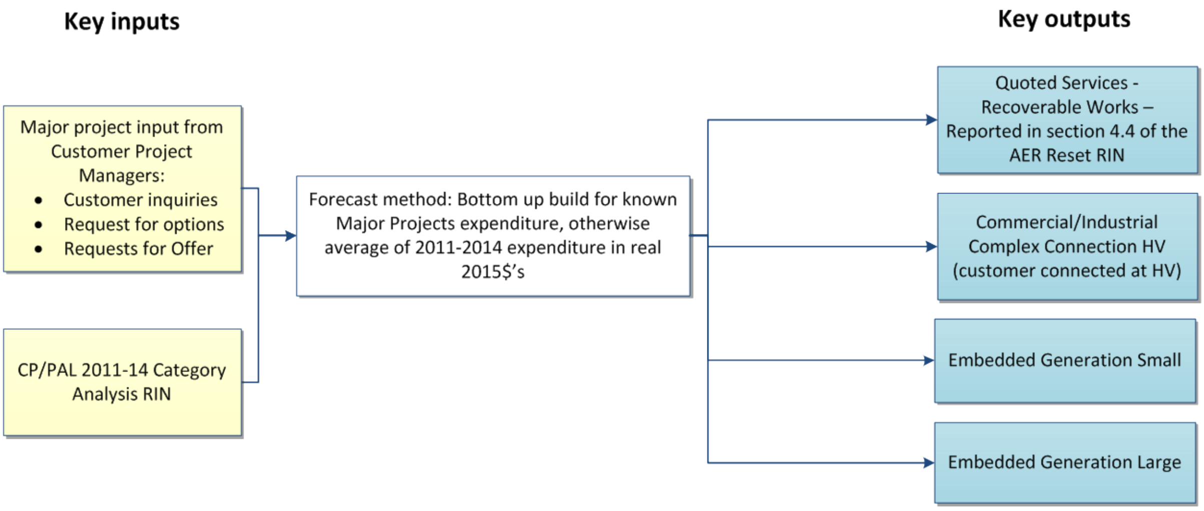
For projects that cost $2.5 million or more, CitiPower has identified projects where the customer has made initial enquiries into the business, or requested options for connections or a connection offer. Based upon correspondence with the customer, CitiPower has assessed that the project is highly likely to proceed and have included the connection in the forecast. The expenditure is based upon estimates from a supplier.

For those connection categories where there is currently no known major project in the latter years of the 2016–2020 regulatory control period, CitiPower has assumed expenditure based on the average major project expenditure in that category for the 2011 to 2014 period.

CitiPower considers that there are a fairly consistent number of smaller projects that cost less than $2.5 million in these connection categories. Therefore, CitiPower has forecast the amount of expenditure for connections based on the average expenditure for non-major projects for the 2011 to 2014 period. The historical expenditure reflects CitiPower's use of competitive tendering processes to source materials, contract labour and services, and is reflective of risks and uncertainty that were borne in undertaking the projects.

An overview of the bottom-up forecasting approach is shown in figure5.4.

Figure 5.4 Overview of bottom-up build process



Source: CitiPower

The model used to forecast new customer connections and customer driven works is provided in the *Customer connections* attachment.

5.2.5 Gifted assets

Guideline 14 currently regulates connection services. In particular, it makes connection and augmentation works contestable in accordance with CitiPower's licence conditions – CitiPower is required to call for tenders to construct the works from at least two other persons who otherwise compete for such works, unless the customer agrees with CitiPower that a tender is not required.[64] This means that customers can elect to use a third party Approved Contractor,[65] rather than CitiPower, to undertake the connection work on 'greenfield assets'.

Where a third party provider completes the construction of a greenfield asset that it has funded, then CitiPower may acquire the asset as a 'gifted asset' once it is connected to the distribution network. CitiPower may then pay a rebate to the customer or developer for the asset.

CitiPower has not included any forecast for gifted assets or rebates in the Regulatory Proposal.

5.3 Historic spend

To date, CitiPower had connected over 15,000 net additional customers to its network in the 2011-2015 regulatory control period. The majority of these connections were smaller residential connections.

CitiPower also completed some large customer connection projects and customer-driven works during that time including:

- connection for new commercial and retail precinct in Batman's Hill, Docklands;
- redevelopment of Melbourne and Olympic Parks sporting and events precinct;

64 Powercor also provides the customer the option of conducting the tender process themselves.

65 Eligible Approved Contracts are accredited by Powercor. Customers are required to select an accredited Approved Contractor.

- undergrounding of sub-transmission lines in Princess St, Kew;
- connection of new apartment complexes in inner Melbourne suburbs;
- connection of a new residential high-rise towers on La Trobe St, Docklands;
- connection to support the redevelopment and extension of two hospitals;
- connection for The Emporium shopping complex on Lonsdale St, Melbourne;
- connection of a retail and residential tower in Southbank;
- connection of a new skyscraper on Collins St in the Melbourne CBD; and
- connection of a new residential development on the old CUB site in Swanston St.

Overall, CitiPower is forecast to overspend its connections and customer driven works regulatory allowance in the 2011–2015 regulatory period by 2 per cent. The actual expenditure is broadly consistent with the AER's allowance, and it appears that the broader economic slowdown did not have a significant impact on building activity in inner Melbourne. This is evidenced by the growth in medium density housing in the inner suburbs and high rise apartments in and around the Melbourne CBD. This may have been stimulated by the change in planning regulations and zonal classifications by the Victorian Government.

Some of the expenditure will also have been driven by 'churn' on the CitiPower network. This is driven by redevelopments or relocations of its customers. For example, the redevelopment of a large department store in the Melbourne CBD was treated as a new connection. Similarly, the relocation of a business to a new office may have been treated as a new connection.

5.4 Forecast spend

CitiPower requires a 14 per cent increase in connections and customer driven works expenditure compared to its actual spend during the 2011–2015 regulatory control period. In addition to relocation works at the West Melbourne and Richmond terminal stations in response to redevelopment works being undertaken by the terminal station owner, AusNet Services, CitiPower's expenditure forecast is driven by new developments and redevelopments in its distribution area, including:

- redevelopment of the E Gate precinct — located at gate 'E' in the rail yard area near North Melbourne railway station, Major Projects Victoria is planning a development to provide housing for up to 10,000 residents and 50,000 square metres of commercial and associated retail space;
- construction of multiple towers for mixed use residential apartments, retail and hotel development located on the former site of The Age newspaper on Spencer Street in the Melbourne CBD;
- further construction of multiple towers for commercial development located at the former site of CUB site in Carlton;
- redevelopment of the Batman's Hill precinct — redevelopment of the 2.5 hectare site opposite Southern Cross station in its 'Melbourne Quarter' which will include in excess of 100,000 square meters of commercial space, approximately 600 residential apartments and 4,000 square metres of retail space;[66]

[66] Refer: http://www.lendlease.com/australia/projects/batmans-hill.

- redevelopment of the Webb Dock port to provide additional opportunities for capacity expansion of the existing terminals and create a third container facility. These works are underway and are expected to be completed in 2016;[67]
- redevelopment of the area to the east of Federation Square East — Major Projects Victoria has sought expressions of interest to redevelop 3.3 hectares of land, including land above the rail lines, as an urban renewal project;[68]
- redevelopment of the Fishermans Bend precinct — Places Victoria has released its draft vision for the redevelopment of this area to provide homes for more than 80,000 residents and a new workplace for up to 40,000 people. This urban renewal will involve a variety of residential developments ranging from warehouse lofts, to townhouses and high rise towers, while continuing to encourage commercial developments;[69]
- redevelopment of the Montague precinct — the City Of Port Phillip is redeveloping the precinct to accommodate 25,000 residents, 13,000 dwellings and 14,000 workers;[70] and
- redevelopment of the Arden Macaulay area — the City of Melbourne has identified the 147 hectare precinct in parts of Kensington and North Melbourne as an urban renewal area that will accommodate significantly more residents and employment growth over the next 30 years.[71]

The increase in forecast expenditure is driven by particular connection categories, notably commercial and industrial connections at HV. This is shown in figure 5.5.

67 Refer http://portcapacity.portofmelbourne.com/pages/past-present-future.asp

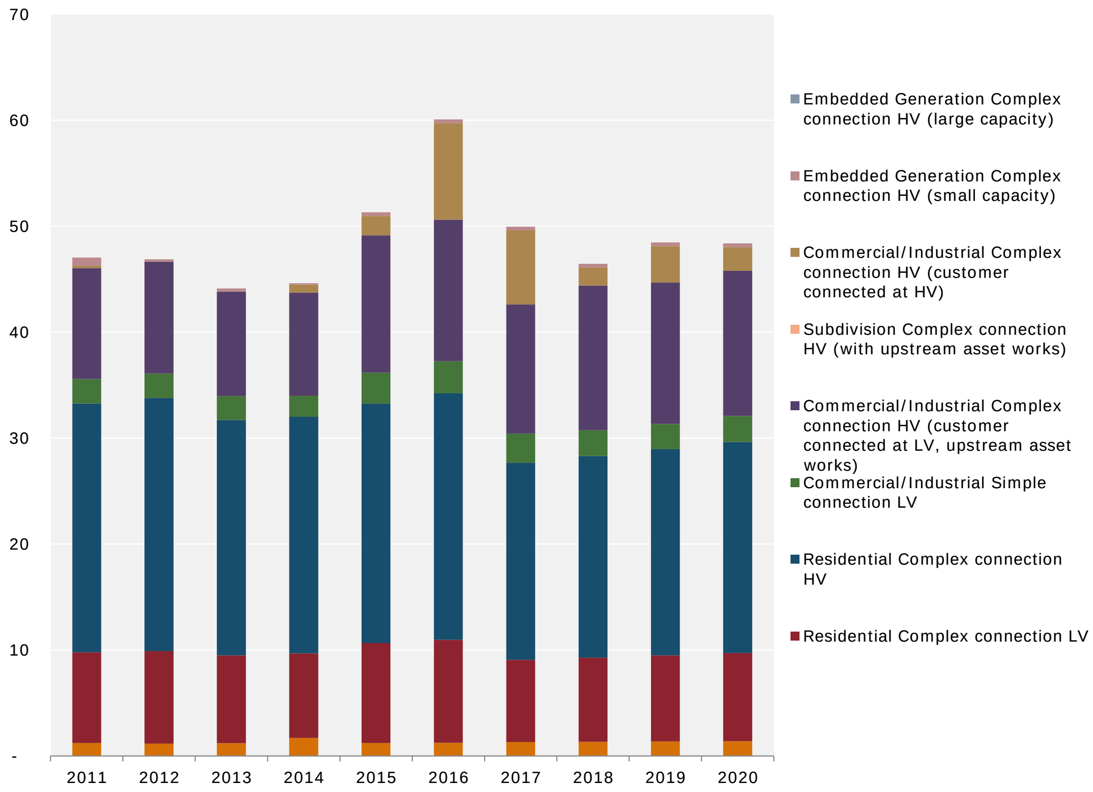
68 Refer http://www.majorprojects.vic.gov.au/project/federation-square-east/

69 Refer: http://www.portphillip.vic.gov.au/Draft_Vision.pdf

70 Refer: http://www.portphillip.vic.gov.au/montague-precinct-structure-plan.htm

71 Refer http://www.melbourne.vic.gov.au/BuildingandPlanning/FutureGrowth/StructurePlans/ArdenMacaulay/Pages/Information.aspx

Figure 5.5 Breakdown of gross direct capital expenditure by connection type, excluding recoverable works and gifted assets ($ million, 2015)



Source: CitiPower

The material connection projects are discussed in the section below.

5.5 Material projects

Table 5.2 provides an overview of the large programs of work over $5 million that CitiPower intends to undertake during the 2016-2020 regulatory control period.

Table 5.2 Material projects for new connections requiring augmentation

Project name	Connection type	Material project no
E Gate	HV connection	CUST 13
Metro Rail temporary supply	HV connection	CUST 14
Spencer St redevelopment	HV connection	CUST 15
RTS relocations	Recoverable works	CUST 16
WMTS relocations	Recoverable works	CUST 17
Yarra Trams	HV connection	CUST 18

Each of these projects is described below.

Please note that the material business cases contain sensitive customer confidential information, including the costs of each project, and are provided to the AER on a confidential basis. The discussion below is based on information in the public domain.

E Gate

Major Projects Victoria has called for expressions of interest to develop E-Gate, a new integrated community on the edge of the CBD and Docklands.[72] The 20 hectare mixed-use development for around 10,000 residents will rejuvenate West Melbourne's rail yards. It represents a planned high quality project consistent with Melbourne's integrated planning approach to accommodate sustainable growth.

E-Gate is expected to proceed by requests to supply individual buildings or areas. The scope to supply each building/area shall be determined as each application is received. All scopes are expected to include new indoor substations with capacity to match the individual building load and new HV feeders or cable extensions as required. New HV feeders will likely come from the adjacent Dock Area (**DA**) zone substation, and DA will need to be augmented to service the total E-Gate load of up to 30MVA.

CitiPower will participate with Major Projects Victoria in developing a connection strategy and will then formally provide design and construction services as requested by the Government or the developer. CitiPower anticipates that the electricity supply works would commence in 2018.

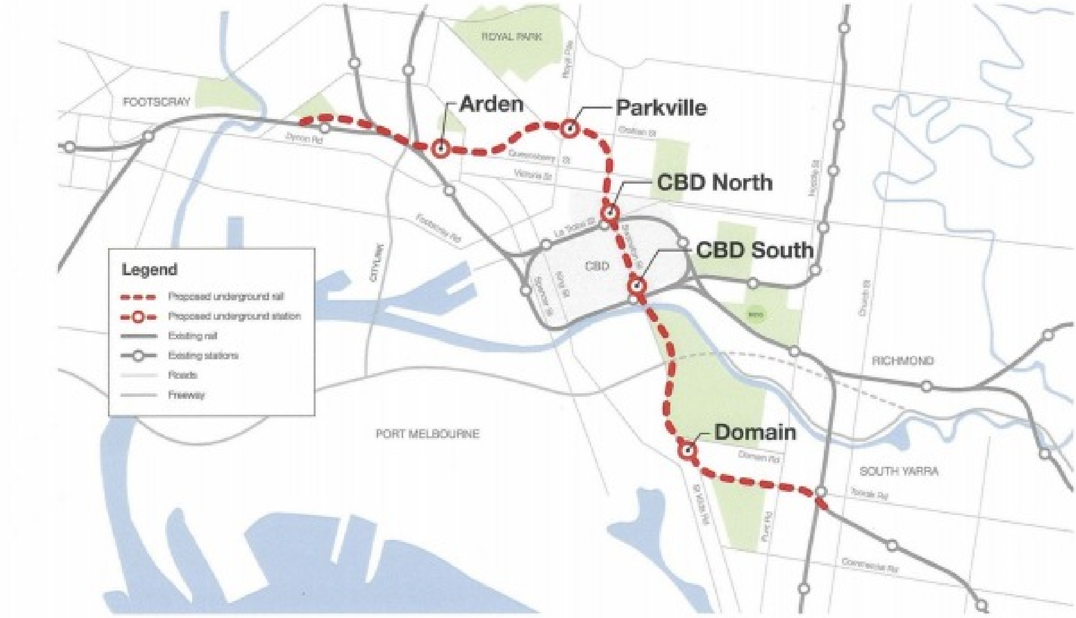
Metro rail temporary supply

The Melbourne Metro Rail Tunnel is a planned metropolitan rail infrastructure project in Melbourne involving the construction of a rapid transit twin rail tunnel to travel from South Kensington railway station to South Yarra railway station. It was initially announced in December 2008 as part of the Victorian State Government's Victorian Transport Plan and has subsequently been confirmed as proceeding by the current Victorian Government in February 2015.

The rail tunnel would provide new underground stations at the Domain Interchange (tram interchange at the corner of St Kilda Road and Domain Road), and the Parkville university/hospital precinct (near Grattan Street or the Haymarket roundabout on Flemington Road), as well as a station in North Melbourne to be known as Arden. The project also aims to provide interchange opportunities at the Melbourne Central railway station and Flinders Street stations. This is shown in figure 5.6.

[72] Major Projects Victoria, New suburb on doorstep of Melbourne's CBD to become a reality, news release, 27 October 2014. Available from: http://www.majorprojects.vic.gov.au/new-suburb-doorstep-melbournes-cbd-become-reality/

Figure 5.6 Proposed Metro Rail Tunnel route



Source: The Age, *Melbourne Metro rail tunnel project revived by Daniel Andrews*, 16 February 2015.

To facilitate the building of the rail tunnel, CitiPower will be required to undertake detailed planning works, install temporary supply for tunnel boring machines and construction works and relocate assets. This project is to install the temporary supply for construction as requested by the customer.

CitiPower is already engaged in design discussions for the rail tunnel. The estimated completion date for the project is estimated to be 2026, with construction expected to begin in 2018.[73]

Spencer St redevelopment

Hong Kong developer Far East Consortium is seeking to replace the 1.1 hectare block at 250 Spencer Street (at the intersection of Spencer, Lonsdale and Little Lonsdale streets) with four towers. The tallest rising about 300 metres accommodating upwards of 93 levels, and be three metres taller than the 92-level Eureka building in Southbank. Another three towers rising between 210 and 240 metres (or about 65 to 75 levels) are earmarked for the balance of the site. The towers may be constructed above a podium with shops and offices.[74]

Construction has commenced with excavation works underway utilising a temporary supply provided by CitiPower.

The developer has been working with CitiPower relating to the permanent supply of electricity. The developer has requested staged supply of electricity, with the full requirement available in 2019.

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73 The Age, *Melbourne Metro rail tunnel project revived by Daniel Andrews*, 16 February 2015. Available from: http://www.theage.com.au/victoria/melbourne-metro-rail-tunnel-project-revived-by-daniel-andrews-20150216-13fmxl.html.

74 The Age, *Site of former Age building to house Melbourne's tallest skyscraper*, 23 November 2013. Available from: http://www.theage.com.au/business/property/site-of-former-age-building-to-house-melbournes-tallest-skyscraper-20131122-2y17y.html.

RTS relocations

Richmond Terminal Station (**RTS**) is owned and operated by AusNet Services. RTS is currently being redeveloped by AusNet Services due to the age and condition of the equipment, and to accommodate future capacity requirements. Works are well advanced and AusNet Services are currently working on the 66kV switchyard rebuild, with completion planned for the end of 2016.

CitiPower is working with AusNet to facilitate the rebuild. AusNet Services will remove the existing 66kV air insulated switchgear and open busbar system from RTS and replace it with indoor Gas Insulated Switchgear (**GIS**). CitiPower has nine existing 66kV circuit exits from RTS which need undergrounding and relocation to the new 66kV GIS indoor switchgear as a result of the proposed works.

AusNet is funding the relocation of CitiPower's 66kV sub-transmission cables, as allowed for by the AER in its final determination.[75] The relocations are being treated as a customer relocation request under Guideline 14.

It is noted that CitiPower is funding the 22kV relocations and the related secondary equipment, as provided in its current regulatory determination.

WMTS relocations

AusNet Services is rebuilding the West Melbourne Terminal Station (WMTS) given its age and condition. The AER has provided an allowance to AusNet for these works in its current regulatory determination.[76]

The AusNet Services redevelopment of WMTS will involve relocation of CitiPower's 66kV sub-transmission cables. The relocations are being treated as a customer relocation request under Guideline 14.

Yarra Trams

The evolution of the Yarra Trams fleet has caused an increased need for electricity. The heritage W-Class trams require 500amps of power, whereas the significantly larger E-Class trams with extra passenger information and air-conditioning require approximately 1500amps. To provide the extra power needed to run the E-Class trams, Yarra Trams require additional substations to be installed across the city in the near future and others upgraded.[77]

CitiPower is working with Yarra Trams to deliver the required increase in electricity capacity.

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75 AER, *Final decision SP AusNet Transmission determination 2014–15 to 2016–17*, January 2014, p. 86-87.

76 AER, *Final decision SP AusNet Transmission determination 2014–15 to 2016–17*, January 2014, p. 74.

77 Yarra Trams, *Substation to substation – Melbourne's tram power infrastructure*, 27 August 2013, available from: http://yarratrams.com.au/media-centre/news/articles/2013/substation-to-substation-melbourne's-tram-power-infrastructure/.

6 Victorian Bushfire Royal Commission

The catastrophic 'Black Saturday' bushfires on 7 February 2009 were one of Australia's worst ever natural disasters.

The Victorian Bushfires Royal Commission (**VBRC**) was established to conduct an extensive investigation into the causes of, the preparation for, the response to and the impact of 15 of the most damaging, or potentially damaging, fires that burned.

The VBRC made 67 recommendations to the Victorian Government about changes needed to reduce the risk, and the consequences, of similar disasters in the future. The VBRC considered that failed electricity assets caused five of the 11 major fires that began that day, and in response eight of the recommendations proposed major changes to the State's electricity distribution infrastructure and operation management.[78]

The proposed expenditure is to implement the recommendations of the VBRC, in accordance with obligations imposed on us by the safety regulator, Energy Safe Victoria (**ESV**).

This section discusses CitiPower's forecast VBRC expenditure as well as its approach to calculating the expenditure.

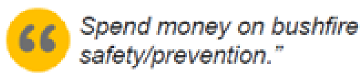
6.1 Overview

CitiPower will include an additional capital expenditure category which includes capital expenditure to implement the changes to infrastructure and operations recommended by the VBRC.

The VBRC was established on 16 February 2009 to investigate the causes and responses to the bushfires which swept through parts of Victoria in late January and February 2009. The VBRC delivered its Final Report on 31 July 2010 which recommended a number of bushfire mitigation initiatives.

Stakeholder engagement research undertaken by CitiPower indicated overwhelming support for initiatives to reduce the risk of bushfires:

- when it came to pricing, online survey participants had net agreement to small price increases that contributed to reduced risk of fire danger and to fund the relocation of undergrounding of electricity, where those consumers did not support funding price rises for any other matters;[79]
- residential focus groups and SME customer-in depth interviews consistently indicated that CitiPower should take all measures available to minimise any potential fire or safety related risk;[80] and
- residential and SME customers outlined that safety and bushfire management is a major responsibility for CitiPower and one that should be take care of regardless of investment.



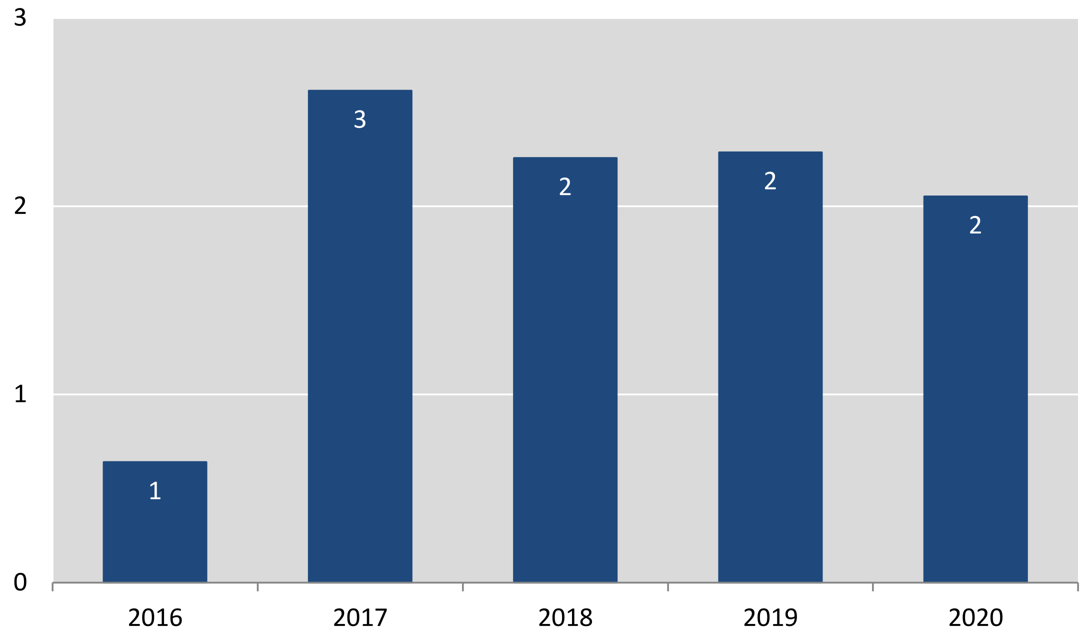
[78] 2009 Victorian Bushfires Royal Commission, *Final Report, Volume 2, Electricity-Caused Fires*, 31 July 2010, p 148. available from: http://www.royalcommission.vic.gov.au/Commission-Reports/Final-Report/Volume-2/Chapters/Electricity-Caused-Fire.html.

[79] Colmar Brunton Research, *CitiPower Stakeholder Engagement Research - Online Customer Survey Results*, Final Report, 18 July 2014, p. 50.

[80] Colmar Brunton Research, *CitiPower Stakeholder Engagement Research Report – Residential Customer Focus Groups and SME Customer Interviews*, 30 April 2014, p. 49.

CitiPower did not have any obligations arising from the VBRC in the current regulatory period, however it will have obligations in the 2016–2020 regulatory control period. The profile of forecast VBRC expenditure is shown in figure 6.1.

Figure 6.1 VBRC direct capital expenditure ($ million, 2015)



Source: CitiPower

It is noted that the AER no longer recognises Environment, Safety and Legal (**ESL**) as a capital expenditure category. CitiPower has included non-bushfire related ESL capital expenditure in replacement capital expenditure.

The expenditure forecasts are to implement specific obligations on CitiPower by ESV that are required to be undertaken during the 2016–2020 regulatory control period. The project expenditure relates to:

- fitting of armour rods and vibration dampers to specific conductors which is intended to reduce wear on conductors and the effects of wind-induced vibration on powerlines, in accordance with the Electricity Safety Management Scheme (**ESMS**);
- conducting a survey of multi-circuit lines to assess whether the conductor clearance is sufficient, in accordance with the ESMS; and
- installation of spacers in aerial lines to maintain conductor clearances and stop conductor clashing in windy conditions, in accordance with the ESMS.

6.2 Background

Following the catastrophic Black Saturday bushfires in 2009, the Victorian Government established the VBRC to consider how bushfires can be better prevented and managed in the future.

The VBRC report made 67 recommendations, eight of which related to electricity supply assets. Two of those were of sufficient complexity that the VBRC recommended further analysis by an expert taskforce, the Powerline Bushfire Safety Taskforce (**PBST**).

Many of the VBRC recommendations are applied to distributors through ESV using its powers under the *Electricity Safety Act 1998* or other legislation. ESV has responsibility for enforcing safety-related:

- Legislation;
- regulations;
- directions;
- the ESMS; and
- relevant Australian Standards.

Obligations placed on CitiPower by the ESV under legislation may result in CitiPower amending its ESMS, or the related Bushfire Mitigation Plan (**BMP**). Once the amended ESMS or BMP is accepted by ESV, then CitiPower must comply with the revised scheme or plan as compliance is enforceable by ESV.

6.2.1 Methodology

The VBRC expenditure forecast is project-based, using a bottom-up build. Where Powercor has undertaken projects in the high bushfire risk areas (**HBRA**) in the current regulatory control period, then CitiPower has used the cost and/or volume information from those projects in the forecasts for those same projects in low bushfire risk areas (**LBRA**).

Table 6.4 sets out the forecasting methodology for each VBRC project.

Table 6.1 VBRC forecasting methodology

Project	Volume estimates	Cost estimates
Armour rods and vibration dampers	Based on detailed assessment of each span using Geographic Information System (**GIS**)	LBRA: based upon HBRA project cost information for 22kV lines HBRA: based on bottom-up build for 66kV sub-transmission lines
Survey of multi-circuit lines	GIS data	Based upon HBRA project cost information
Installation of spacers on multi-circuit HV lines	Based on outcomes from HBRA survey	Based upon HBRA project cost information
Multi circuit re-builds	Based on outcomes from HBRA survey	Bottom-up build based on historical costs for similar projects

Where the cost estimates are based on HBRA or historical project cost information, those costs are reflective of any competitive tendering processes to source materials, contract labour and services, and risks and uncertainty that were borne in undertaking the projects.

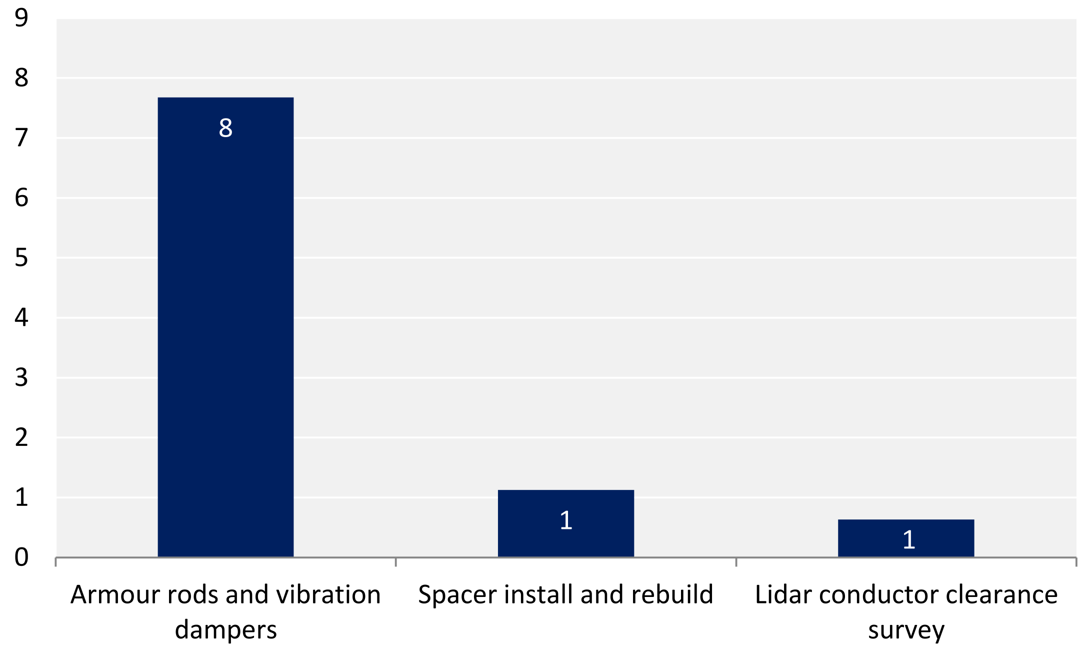
Greater detail on the projects and costs and volumes are provided in section 6.3.

6.3 Forecast spend

The forecast expenditure for VBRC relates to specific projects that CitiPower is obligated to undertake during the 2016–2020 regulatory control period.

An overview of the expenditure, by project, is shown in figure 6.2. The distribution services to be provided by the proposed assets are network services.

Figure 6.2 CitiPower VBRC direct capital expenditure by program ($ million, 2015)



Source: CitiPower
Note: direct costs excluding real escalation

Table 6.3 provides an overview of the source of the obligation that has been imposed on CitiPower. A description of each of these projects is then provided in turn below.

Figure 6.3 Source of obligations for VBRC expenditure

Project name	Obligation source
Armour rods and vibration dampers	ESMS
Lidar conductor clearance survey	ESMS
Spacers in aerial lines	

Source: CitiPower

Armour rods and vibration dampers

CitiPower is required to install armour rods and vibration dampers in low bushfire risk areas by 1 November 2020.

Recommendation 33 of the VBRC proposed that:[81]

The State (through Energy Safe Victoria) require distribution businesses to do the following:

- *fit spreaders to any lines with a history of clashing or the potential to do so*

[81] 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010. p. 30.

- *fit or retrofit all spans that are more than 300 metres long with vibration dampers as soon as is reasonably practicable.*

Subsequently, ESV issued a Direction on 4 January 2011 under section 141(2)(d) of the *Electricity Safety Act 1998*, which required CitiPower to ensure that its ESMS provides that:[82]

> *(a) Armour rods are to be fitted to all conductors as specified in the drawings VX9/7037 and VX9/7037/1 of the Victorian Electricity Supply Industry Overhead Line Manual, Volume 1 or other equivalent or higher standard approved by Energy Safe Victoria;*
> *(b) Vibration dampers are to be fitted to all conductors as specified in the drawings VX9/7037 and VX9/7037/1 of the Victorian Electricity Supply Industry Overhead Line Manual, Volume 1;*
> *(c) Armour rods and vibration dampers are to be fitted to all other spans where there is evidence of wear of the conductor or armour rod due to vibration;*
>
> *…*
>
> *(e) A program to ensure that all locations requiring armour rods or armour rods and vibration dampers to be fitted is completed:*
>
> - *In hazardous bushfire risk areas — before 1 November 2015; and*
> - *In all other areas — before 1 November 2020*.
>
> *In developing the program, priority shall be given to those spans exposed to conditions conductive to vibration with consideration for the length of time those lines have been exposed to those conditions and the fire risk of the location in which they are installed.*

Armour rods are protective devices designed to reduce wear on conductors at the contact points with insulations and conductor ties, vibration dampers are intended to reduce conductor vibration and therefore the impact of this vibration on conductors and ties.

In its letter to ESV on 1 February 2012, CitiPower set out the program of work to install armour rods and vibration dampers. In LBRA, the fitting of program was planned to start in 2016 and being completed in the first half of 2019.[83]

CitiPower subsequently updated its ESMS to include the requirements of the Direction.

Volume and cost of armour rods and vibration dampers

In LBRA, CitiPower has estimated that there are 17,230 spans where armour rods and vibration dampers are required to be installed. The figure is based on a detailed analysis of the characteristics of each span in the network using the Geographic Information System.

The unit cost is based on Powercor's historic average cost of installing armour rods and vibration dampers per span in HBRA, which takes into account the start-up costs associated with the program, such as the re-tendering for this program of work, contractor training and mobility solution, design and work issues.

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[82] ESV, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of armour rods and vibration dampers*, 4 January 2011.

[83] CitiPower and Powercor, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of armour rods and vibration dampers,* 1 February 2011.

Lidar conductor clearance survey

CitiPower is required to undertake a survey of multi-circuit lines in LBRA during the 2016–2020 regulatory control period to identify all spans that do not comply with the separation requirements, and to then install a spacer or rebuild the line for those spans that do not comply.

Recommendation 33 of the VBRC proposed that:[84]

> *The State (through Energy Safe Victoria) require distribution businesses to do the following:*
>
> - *fit spreaders to any lines with a history of clashing or the potential to do so*
> - *fit or retrofit all spans that are more than 300 metres long with vibration dampers as soon as is reasonably practicable.*

Subsequently, ESV issued a Direction to CitiPower on 4 January 2011 under section 141(2)(d) of the *Electricity Safety Act 1998*, which required CitiPower to ensure that its ESMS provides that:[85]

> *(a) Low voltage spreaders shall be fitted to all spans of bare low voltage conductor in hazardous bushfire risk areas;*
>
> *…*
>
> *(d) The separation between all conductors, with the exception of insulated conductors, shall be maintained in accordance with the minimum separation required in Section 10.3 – Conductors on the same supports (same or different circuits and shared spans) of the current release of the Energy Networks Association document C(b)1 – Guidelines for Design and Maintenance of Overhead Distribution and Transmission Lines;*
>
> *(e) A program to identify all spans that do not comply with (d) above shall be developed by 1 February 2011;*
>
> *(f) All spans that do not comply with the requirements of (d) above shall be constructed to comply, or fitted with spacers:*
>
> - *in hazardous bushfire risk areas – before 1 November 2015; and*
> - *in all other areas – before 1 November 2020.*
>
> *…*

On 1 February 2011, CitiPower responded to ESV outlining its plan to undertake a survey of spans in LBRA commencing in the second half of 2015 and completed by July 2019. The survey would assess all spans of bare open wire multi-circuit lines. The timetable would allow completion of any identified works to install spacers or reconstruct the span to comply with the separation requirements by 1 November 2020.[86]

CitiPower amended its ESMS to include the requirements of the Direction, thus satisfying the Direction. CitiPower is therefore obligated to complete these works.

Volume and cost of survey

The ESV Direction contained a requirement for CitiPower to develop and program to identify all spans that do not comply with the separation requirements outlined in the Energy Networks

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84 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010. p. 30.

85 ESV, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines*, 4 January 2011.

86 CitiPower and Powercor, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines,* 1 February 2011.

Association (**ENA**) document C(b)1 – Guidelines for Design and Maintenance of Overhead Distribution and Transmission Lines.

The methodology to identify non-compliance spans was set out in CitiPower's letter to the ESV on 1 February 2011. The letter noted that to ascertain the clearance assessment of multi-circuit spans, the three-dimensional location all points of attachment for each conductor and the mid-span locations must be determined. Design calculations would then be required to allow for expansion and contraction of the conductors under variations in the ambient temperature and electrical load at nominal stringing tension.[87]

CitiPower estimates that 360km of lines will need to be surveyed in 2016. The length of line has been assessed using the GIS system.

The survey will be conducted in 2016 using Lidar technology, which involves specially equipped vehicles following the route of the relevant sections of the network to capture the relevant information.

As Powercor tendered for and engaged a contractor to conduct a survey of the multi-circuit spans during the current regulatory control period, CitiPower has used those contract rates from that survey plus internal design costs in forecasting the expenditure for the LBRA survey.

Spacers in aerial lines

The Direction requiring that a survey of multi-circuit lines be undertaken required that spans that do not comply with the required clearances be constructed to comply, or fitted with spacers.

Volume and cost of spacers

The volume of spans estimated to not comply with the separation requirements in LBRA is 354. This volume is based on Powercor's experience in the HBRA portion of the network where 10,400 multi-circuit spans were surveyed and 7.8 per cent were found to not be compliant. Of those spans:

- 30 per cent were able to be fitted with a spacer, as those spans were either 22kV or 11kV; and
- 70 per cent required a rebuild as the spans involved 66kV sub-transmission line and there is currently no spacer that can be used on such lines.

For LBRA, the same ratios from the previous survey have been applied, as shown in table 6.2, together with the rebuilds on 66kV sub-transmission lines.

Table 6.2 Volumes of works relating to spacers in aerial lines

Period	2016	2017	2018	2019	2020
Installation of spacers		177			
Rebuild span			59	59	59

Source: CitiPower

In relation to the unit cost per span to install a spacer, CitiPower has used the average cost per span that Powercor incurred in 2014 for the installation of spacers in HBRA.

87 CitiPower and Powercor, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines,* 1 February 2011.

The cost of rebuilding spans has been based upon the historical cost of replacing the crossarm associated with sub-transmission lines on a multi-circuit span, to ensure that the clearance space between the sub-transmission line and the 22kV feeders meets the minimum separation requirements. The rebuild cost is consistent with the 66kV crossarm replacement cost in the replacement capital expenditure category, together with design costs for each span. The cost assumption is considered to be conservative as it is unclear the extent of the rebuilds required, or whether a more costly pole replacement would be required.

7 IT and communications

> As CitiPower moves towards embracing a network of the future, IT provides critical support to enable integrated digitalisation across all aspects of its operations and network.
>
> By prudent and efficient investment in, and management of, its IT and communications systems and infrastructure, CitiPower is able to provide safe and reliable services that supply energy to its customers.
>
> IT is used to support critical business direction across CitiPower, using solutions that deliver innovation through pragmatic use of technology and deliver better customer service.
>
> CitiPower recognises its customers' need for access to energy consumption information that allows them to self-determine their energy usage practices and demand. A key focus for CitiPower is to provide customer services that make it easier for its customers to make informed choices through access to real time information across multiple platforms.

This section discusses CitiPower's historical and forecast Information Technology (**IT**) and communications expenditure as well as the approach used in calculating the forecast expenditure.

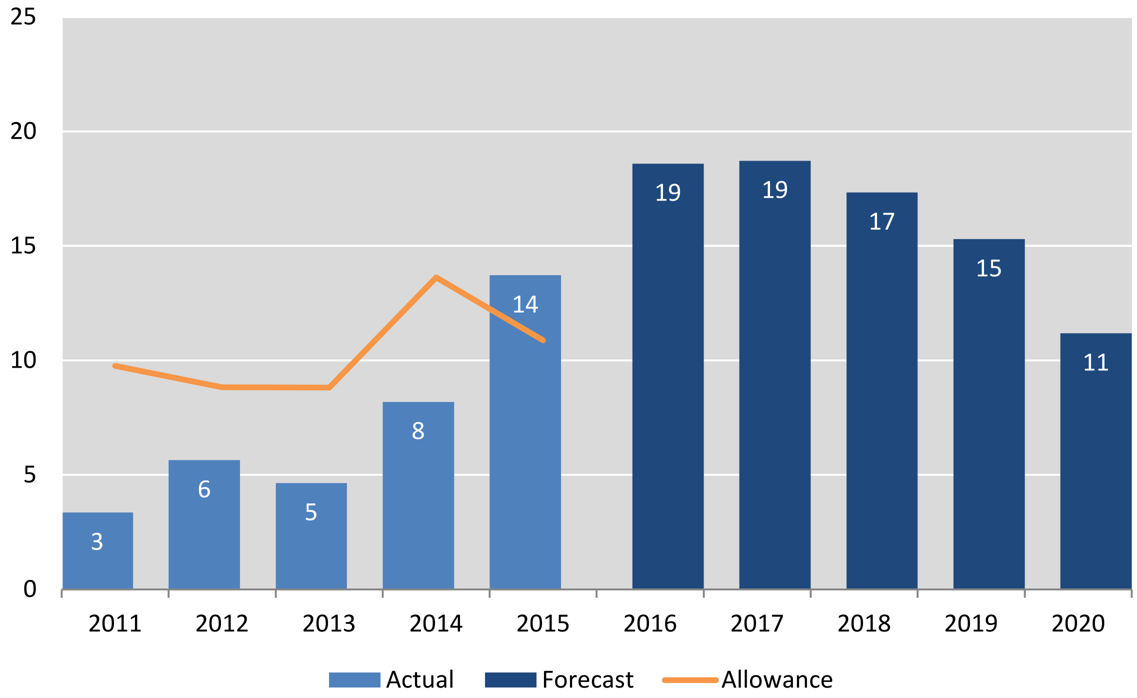
7.1 Overview

CitiPower's capital expenditure forecasts for IT and communications support the directions and strategies of the business. IT services provide the critical energy management, metering and information services that enable the efficient and reliable delivery of energy to customers. Underpinning these services are IT support services for network; asset management; works management; metering and corporate IT services that provide the architecture and information to successfully operate the network business.

The foundation of these IT services is an IT infrastructure of hardware and applications, as well as devices, that must be proactively, prudently and efficiently managed through-out their lifecycle to meet required business service levels.

An overview of the historical and forecast IT and communications expenditure is shown in figure 7.1. This figure does include historical IT expenditure to support the smart meter deployment which has been recovered through a separate regulatory process.

Figure 7.1 IT and communications direct capital expenditure ($ million, 2015)[88]



Source: CitiPower

CitiPower's forecasts for IT capital expenditure are broken down into a number of streams[89], representing investment in a number of key capabilities and underlying infrastructure that are critical in supporting business operations to provide safe, reliable and efficient energy services to customers. Investment in the following streams is necessary to maintain current service levels and systems while also investing in new technology to support industry changes:

- **compliance** — maintaining regulatory, statutory, market and legal compliance via investment in systems, data, processes and analytics to provide the functionality and reporting capability to efficiently comply with statutory and regulatory obligations;
- **currency and capacity** — maintaining vendor support for solutions and core software within acceptable and consistent versions and proactively ensuring that business needs and service definitions are fulfilled using a minimum of computing resources, and that applications have the capacity to support business volumes within service level targets;
- **customer engagement** — investment in systems and capabilities that support the increasing complexity of market relationships and customer needs. Responding to evolving industry forces, energy market and industry changes that are being progressed by regulators to increase innovative participation by customers in the market;
- **device replacement** — optimising the investment in end user devices to enable workforce operability whilst optimising cost and performance;

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88 2011 to 2014 are actual costs, 2015 to 2020 are forecast costs.

89 CHED Services, *IT Service Delivery, Investment Stream Strategies 2016-2020 stories*, April 2015.

- **infrastructure** — prudently optimising asset lifecycles of infrastructure assets to ensure agreed service levels can be met at the lowest lifecycle cost and supporting normal business growth;
- **security** — ensuring customers continue to receive a reliable distribution of controlled power, by monitoring, managing and mitigating threat of cyber and network security breaches in a prudent manner; and
- **smarter networks** — enabling networks for the future through targeted investment in technologies that maintain and improve customer service standards and enable new and innovative services.

These streams are all discussed in further detail in the forecast expenditure section below.

CitiPower's forecast expenditure is reflective of customer needs; encapsulates changes in the regulatory frameworks; and offers the business a forward thinking and innovative approach to the needs of a 2020 customer and in doing so balances a prudent approach to the introduction of new technology and the exploitation of existing systems.

A key focus of CitiPower's investment is to facilitate customer choices in an innovative and competitive energy market. This emerging market need will drive requirements for new systems, processes and capabilities over the next five years.

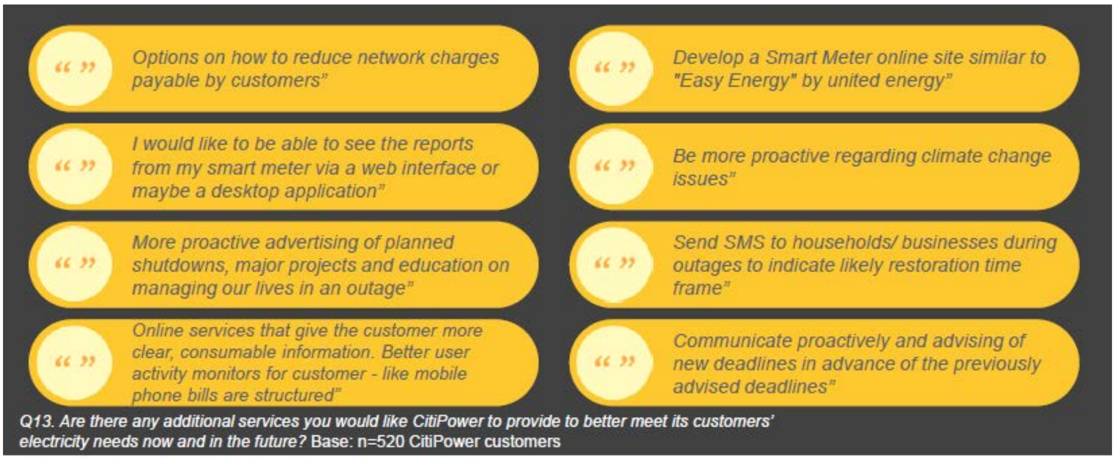
To respond to the growing customer demand for greater pricing flexibility and access to information CitiPower will implement a Customer Relationship Management (**CRM**) system together with replacing the existing billing system to support and manage customer access to their information and support more personalised service, which is supported by its stakeholders. For example, in response to the Directions and Priorities consultation, the City of Melbourne also supported greater access to usage data, noting that:[90]

> *The deployment of smart meters and in home displays presents opportunities to engage more directly and comprehensively with customers to information and educe about energy choices and energy use behaviours.*

This view was also expressed in responses to the online survey, where customers indicated that access to consumption data was an additional service that could be provided to better meet their current and future electricity needs, as shown in figure 7.2.

[90] City of Melbourne, Directions and Priorities Consultation Paper response, 17 October 2014, p. 7. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/13.City-of-Melbourne-17-October-2014.pdf.

Figure 7.2 Additional services that would help customers



Source: Colmar Brunton Research, *CitiPower stakeholder engagement research – online customer survey results*, 18 July 2014, p. 45.

Customers are also keen for CitiPower to continue to innovate, as it moves along the journey to a smarter grid by building upon the information available through the deployment of smart meters. Stakeholders consider that a smarter grid is a highly appealing and necessary area for investment. In response to a question in its Directions and Priorities consultation about whether customers are satisfied that CitiPower is taking a targeted and considered approach to modernising its network, a CitiPower customer noted that: [91]

> *…investment in smart networks is essential and full utilization of smart metering technology to improve supply quality and reliability is great.*

The City of Melbourne also noted that: [92]

> *The City of Melbourne supports efforts to research and deploy technologies which build a smart and efficient electricity grid, incorporating storage, distributed generation and smart use of data and information. The ability of smart grids to support the adoption of greater energy efficiency, reduced reliance of fossil fuels and contribution to reduction of greenhouse gas emissions is of particular importance to the City of Melbourne and aligns with our key strategic objectives set out in the Zero Net Emissions by 2020 strategy.*
>
> *We believe there are opportunities to deploy emerging technologies strategically to alleviate existing and future network pressures (such as battery storage, power correction devices, and distributed generation).*

Through interviews with residential customer focus groups and SMEs, stakeholders indicated that their future needs would be best met with a smart grid to enable choices and flexibility as well as the efficient upgrade of ageing infrastructure. Smart grid was seen as an area that is highly worthy of investment to residential customers, and was viewed positively by all SME customers due to the

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[91] Bill Pitt, Email submission to Directions and Priorities, 29 October 2014. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/14.Bill-Pitt-29-October-2014.pdf.

[92] City of Melbourne, Directions and Priorities Consultation Paper response, 17 October 2014, p. 7. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/13.City-of-Melbourne-17-October-2014.pdf.

flexibility and opportunity it provides SMEs to generate their own electricity and additional electricity which could be returned to the grid for a financial benefit.[93]

7.2 Background

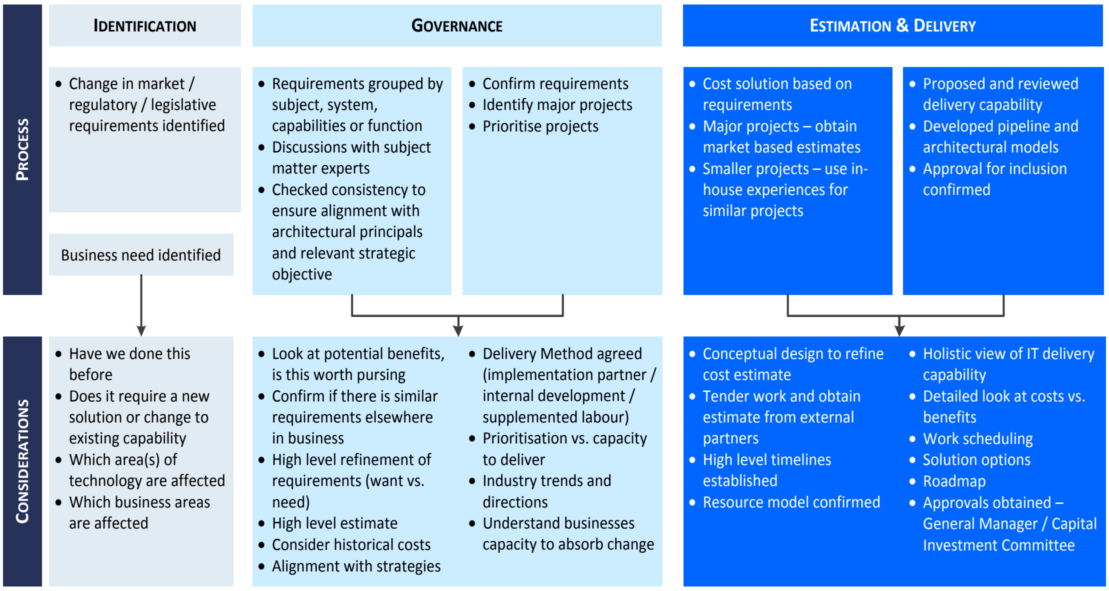
This section describes CitiPower's methodology for forecasting IT and communications capital expenditure.

7.2.1 Forecast methodology

The methodology used to forecast expenditure required for the 2016–2020 regulatory control period is consistent with the methodology and processes that CitiPower uses for the costing and estimation of all IT projects.

This three phase approach of identification, governance, and estimation and delivery are outlined in figure 7.3.

Figure 7.3 Project initiation process and considerations



Source: CitiPower

CitiPower has identified the business needs for the IT and communications program through an iterative process which has involved:

- identifying hardware and software replacement cycles and assessing the most prudent method of maintaining currency;
- anticipating future business needs through analysis of IT and energy industry trends, as well as considerations of CitiPower IT strategy and direction;
- understanding current and future market, regulatory and legislative changes, as well as the implications for the IT systems; and
- consideration of varying internal and external support models, cloud and purchase models.

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[93] Colmar Brunton Research, *Powercor stakeholder engagement research report – residential customer focus groups & SME customer interviews*, 30 April 2014, p. 34.

The rapid changes in the IT and communications landscape require a continual review and reworking of the business plans and proposed solutions. CitiPower must ensure that for each business need that the impacts on systems and processes are clearly understood, which may lead to refinement of the potential solutions.

CitiPower's governance processes include consideration of cost estimates for different solutions and delivery options for each business need. The original requirement and preferred solution is then reviewed to re-confirm the required scope, and to determine whether there are other similar requirements sought by the business where delivery synergies can be achieved. The requirements and the delivery options are also checked for alignment with CitiPower's overarching strategic direction, as well as IT strategies.

Finally, robust cost estimates for each requirement are prepared, which have been sourced from:

- market based outcomes from competitive tender processes – costs reflect the rates contained within CitiPower's contracts with the successful tenderers for the device replacement stream and labour rates following the establishment of contractor and consulting panels;
- estimated data obtained from contractors or vendors – robust cost estimates have been obtained for large projects including the CRM, billing replacement and RIN projects, the smarter networks and security streams;
- actual historical costs for similar projects – this process has been used for many of the smaller currency stream projects; and
- historical tender processes or similar projects; this process was used for some infrastructure-related projects.

Where the cost estimates are based on historical costs for similar projects, those costs are reflective of any competitive tendering processes to source materials, contract labour and services, and risks and uncertainty that were borne in undertaking the projects.

The timeline for the delivery of each business need is considered together with other requirements. CitiPower has flexible resourcing arrangements so that the program of work can be delivered and implemented to meet the timeframes.

Each IT and communications system change has been evaluated by CitiPower to ensure it meets the identified need, is prudent, efficient, and can be implemented in the required timeframe.

7.2.2 Key drivers of expenditure

Key drivers of IT and communications expenditure are the IT lifecycle and replacement, upgrades and maintenance of existing systems to ensure that they remain up-to-date. In addition, CitiPower may be required to introduce new systems or functionality to meet industry or regulatory requirements. These matters are discussed below.

IT Lifecycle

IT expenditure is cyclical for each system — expenditure peaks following the purchase and implementation of a new system, and then falls as the system is maintained and upgraded over time. As the system approaches its end-of-life the expenditure increases again as patches and fixes are made to prolong the life before it is ultimately replaced.

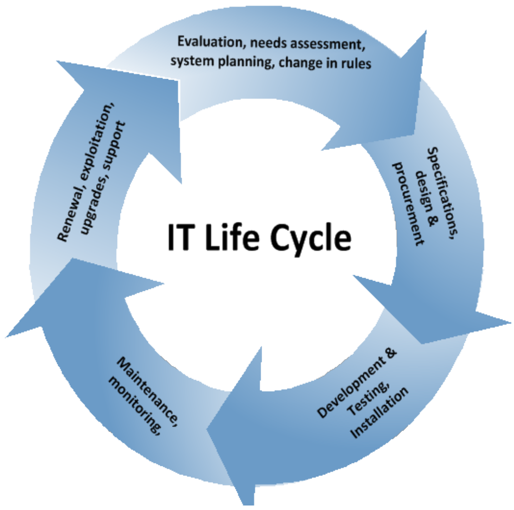
CitiPower's lifecycle management objective has been to meet the business need in a timely and efficient manner, reusing technology where technically possible and introducing proven technologies and taking opportunity to realise generational technology when appropriate. The length of IT lifecycle varies for every IT system and for every company that uses that system.

CitiPower follows the approach of investing in major applications then operating and modifying them to meet changed requirements for as long as possible.

Triggers for reimplementation are a blend of:

- fundamental change in business requirements often due to regulatory or market changes;
- step changes in underlying technology rendering application unsupportable;
- shifts in the environment in which the business must operate which require fundamental changes to the IT architecture (e.g. operation and support of AMI network);
- adoption of new technologies to support underlying business effectiveness (e.g. mobility); and
- increases in the scale of operation such that the legacy applications and technologies are no longer adequate to support business operations at the required level of service or transaction volume.

Figure 7.4 The IT lifecycle



Source: CitiPower

During the 2016-2020 regulatory control period there will be an intersection of a number of these triggers:

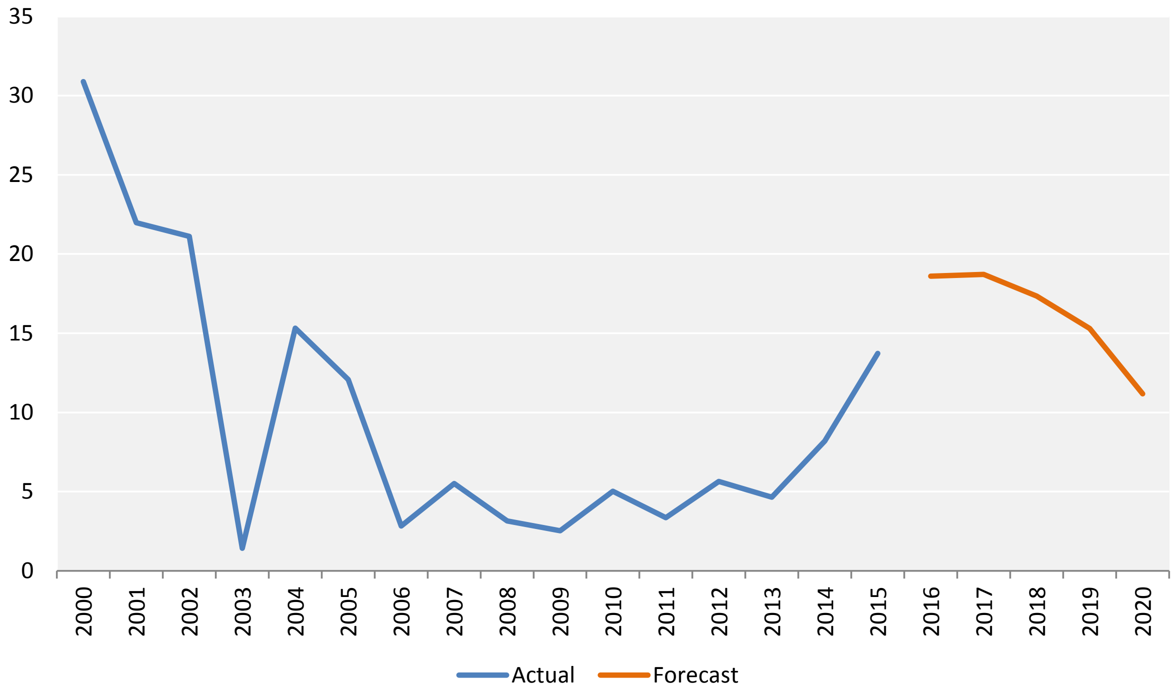
- regulatory change — changes in business requirements following the AEMC's Power of Choice review, the proposed introduction of metering competition, and the AER's reporting for Regulatory Information Notices (**RIN**);
- support of new and innovative business operations imperatives and technology — continued movement towards a smarter network;
- expansion of mobility devices and applications and integration into IT and communications systems to support business effectiveness and customer expectations;
- generational change in a number of technical architectures that support underlying architectural building blocks;
- increased usage and storage of multiple data types for reporting and operational management e.g. metering events, Lidar and network control point monitoring; and
- fundamental changes in the requirements for the security of the network and its communications systems with heightened external threats compared to the current regulatory control period.

The combination of these events is reflected in the cyclical upswing in required IT expenditure in 2015-2017 followed by a period of consolidation from 2018 to 2020.

CitiPower's overall expenditure profile for IT follows this lifecycle pattern, as shown in figure 7.5. Two of the larger systems in the IT landscape are the SAP enterprise software, which manages business operations, and the Customer Information System – Open Vision (**CIS-OV**) billing system, both of which were implemented in around 1999/2000. In the 2000-2008 period, CitiPower's focus was on small enhancements to these relatively new existing systems.

Also, from 2006 to 2013 the standard control systems were maintained and enhanced due to the focus on the implementation of smart meter related systems (not included in the analysis below). In 2014 and 2015, CitiPower has re-commenced its investment in these standard control systems.

Figure 7.5 IT non-network capital expenditure ($ million, 2015)



Source: CitiPower

Recurrent vs non recurrent spend

CitiPower has applied a consistent methodology to distinguish between recurrent and non-recurrent expenditure, based upon the methodology set out in the Category Analysis RIN. In particular:

- recurrent expenditure relates to replacement, upgrades and maintenance of existing functionality and systems in the CitiPower IT landscape. For example, this includes replacement of the billing system, device replacement, and upgrades, expansion and refresh of infrastructure; and
- non-recurrent expenditure relates to new functionality or new (not replacement) systems that will be introduced to the CitiPower IT landscape. For example, this includes the Customer Relationship Management system (**CRM**), the new RIN reporting requirements and SSL Decryption software incorporated into the security stream.

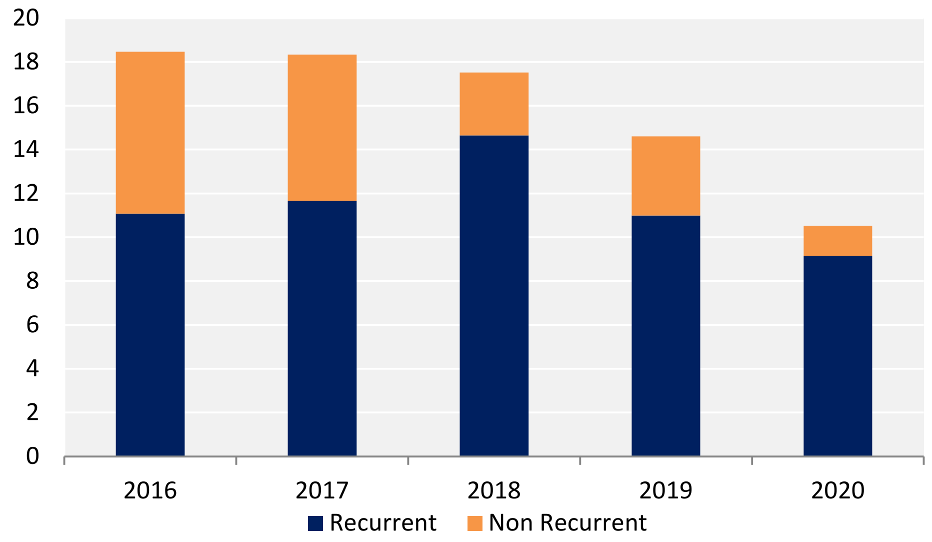
This approach to the recurrent/non recurrent split is reflective of CitiPower's approach to:

- investing in new technology where appropriate then managing the effective life of that investment through fit-for-purpose enhancement and modification;

- recognition of the importance of solid strategic investment in core IT systems that can be efficiently enhanced; and
- the increasing scope of IT systems supporting the business and the refresh requirements across that base.

CitiPower has identified whether the expenditure contained in each project or program of work is recurrent or non-recurrent expenditure. Overall, its expenditure is forecast to be 73 per cent recurrent and 27 per cent non-recurrent over the 2016–2020 regulatory control period, although it varies year-to-year within that period as shown in figure 7.6.

Figure 7.6 Recurrent / non-recurrent split per year ($ million, 2015)



Source: CitiPower
Note: direct costs excluding real escalation

The high level of recurrent expenditure is reflective of CitiPower's position within the IT lifecycle where many existing systems are in the maintain and run stages of their lifecycle, than in the replace. The breakdown of the recurrent and non-recurrent IT and communications expenditure into the various streams is shown in table 7.1.

Table 7.1 IT recurrent and non-recurrent spend by stream

Stream	% recurrent	% non-recurrent
Compliance	21	79
Currency	100	0
Customer engagement	52	48
Security	74	26
Smarter network	81	19
Infrastructure	100	0

Device replacement	100	0

Source: CitiPower

The relative investment in IT streams reflects both the relative nature of their investment profiles and cycles. The currency stream is essentially to maintain the current state so therefore has no non-recurrent expenditure whereas customer expectation has driven a relatively high level of new requirements (or non-recurrent spend) in customer engagement. The high non-recurrent expenditure in compliance reflects the range of new requirements expected in this stream. Both the security and smarter networks streams reflect the continued investment in current systems and introduction of new and innovative solutions.

7.2.3 Deliverability

The service delivery pipeline for IT programs takes into account the prioritisation of works, together with the capacity and capability of CitiPower's systems and resources.

IT resource planning draws on the IT governance works program to identify the specific resources and skills required to deliver individual projects and programs of work. This program profile is used to develop a program plan that ensures the delivery of projects and programs within specified timeframes in the most efficient and cost effective manner.

The delivery approach is determined by the IT capital portfolio governance group, taking into account resource availability, required skill sets, delivery timeframe and project requirements. Options for delivery are:

- internal delivery — internal employees manage and deliver the project;
- supplemented business labour — a blend of internal employees and labour hire staff drawn from a panel of preferred supplier contractor companies, manage and deliver the project; or
- implementation partner — drawn from a competitive tender process with a panel of preferred suppliers, the implementation partner manages and delivers the project, using internal employees where necessary.

Establishment of the proportion of delivery to be performed internally and externally has taken into account:

- skill and labour flexibility;
- variability in the timing and extent of skill demand;
- retention of core intellectual property within the business;
- access to leading edge delivery capabilities and implementation approaches;
- ability to leverage like projects delivered previously by external providers; and
- supply availability of the various labour classes.

CitiPower has determined the number of work hours required to deliver the IT capital program is forecast to maintain its 2015 service delivery level in the 2016–2020 regulatory control period.

Each project or program of work has been estimated using market based outcomes from competitive tender processes; historical tender processes or similar projects; estimated data obtained from contractors or vendors; or actual historical costs for similar projects. The estimated hours to deliver from all the IT projects have been combined to produce a yearly forecast. This forecast is set out in table 7.2 below:

Table 7.2 IT work hour requirements

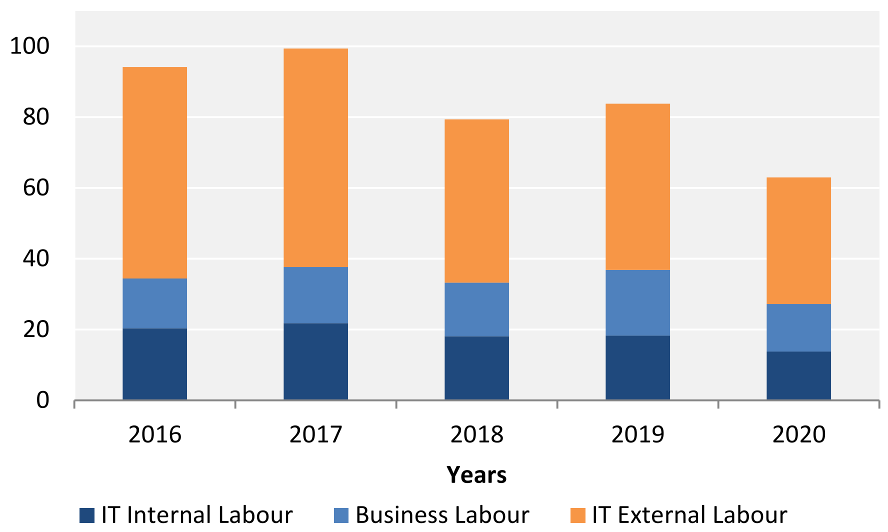
	2016	2017	2018	2019	2020
Total work hours	94,147	99,351	79,332	83,784	62,903

Source: CitiPower

The largest program for delivery over the 2016–2020 regulatory control period is the implementation of the new billing system, scheduled in 2016 and 2017. The timing is dictated by the rule changes following the Power of Choice review. Given constraints in terms of internal labour resources, CitiPower will need to draw upon its flexible labour resources using supplemented business labour and implementation partners to deliver this program.

The breakdown of the resource allocation is split between IT internal labour, business labour (non-IT) and external labour as seen in figure 7.7.

Figure 7.7 Deliverability - IT and communications capital program



Source: CitiPower

7.3 Historical expenditure

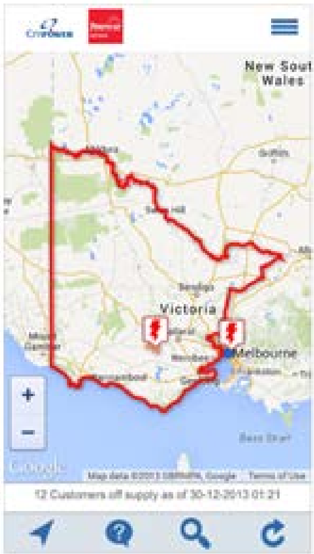
The seven work streams proposed in the 2016-2020 regulatory proposal are reflective of CitiPower's areas of investment during the current 2011-2015 regulatory control period. CitiPower has successfully delivered a range of initiatives during this time, many of which provide the foundation for further investment and innovation going forward.

CitiPower has delivered the following initiatives within the IT and communications stream:

- **currency —** the ever changing nature of IT means that ongoing investment is required to keep systems, software and infrastructure current. In the 2011-2015 regulatory control period CitiPower has undertaken an extensive currency program. CitiPower has chosen to invest in proven, reliable and industry leading software and application solutions, upgrading, enhancing and modifying to meet changing business and industry needs as an alternative to re-implementing and changing software to attempt to meet these needs. Currency has included upgrades to many systems including the billing, treasury management, fleet management, service suite, telephony and Oracle 12c systems, as well as mapping the low voltage network into the GIS and improving its website capability;

- **customer engagement —** the historical spend associated with customer engagement is reflective of CitiPower's ongoing commitment to better engage and service its customers. This has included the introduction of the REConnect application to streamline connection applications, and other improvements to customer engagement including a claims management tool and changes to push communications for all account types;
- **security —** the review of security and vulnerabilities has been a growing process over the last five years. This process has been influenced by the introduction of smart meters and the constant increase of threats and the sophistication of those threats against CitiPower's systems. To keep pace with these evolving threats CitiPower has continued to initiate projects to increase its security posture and rectify any concerns to further protect its IT systems and infrastructure during the 2011–2015 regulatory control period, including implementation of new firewalls to prevent intrusions into the web applications, corporate and SCADA systems together with implementation of a new security information event management solution to improve IT security incident and response capabilities;
- **mobility and device replacement —** during the 2011–2015 regulatory control period CitiPower has maintained and continued to grow its personal computing (**PC**), printer and workstations fleets and substantially expanded its mobile computing capabilities. The introduction of the smart phone and tablets has fundamentally changed CitiPower's operating model. Initially thought of as a nice-to-have 'fancy telephone' these smart devices allow access to real time data, anywhere. The following development, design and implementation initiatives were enabled by the use of smart devices: network fault and outages apps which provide geospatial visualisation of unplanned outages to employees and customers, 'Never Compromise' health and safety app that allows field reporting of hazards and incidents, and a field work issue app that supports the field deployment of armour rods and vibration dampers;
- **infrastructure —** CitiPower's historical spend for its infrastructure program is cyclical in nature and the 2011-2015 spend profile is reflective of this pattern. Examples of projects undertaken for infrastructure include: increases in capacity and technical refresh for a range of servers, storage, data protection, routers and network infrastructure, including the network core switch infrastructure; migration from physical to virtual servers for Microsoft Exchange and migration to new data protection infrastructure; updates to B2B systems to meet AEMO requirements as well as changes to the superannuation, payroll and the incident management system to achieve compliance with various regulations, laws, guidelines and specifications applicable to CitiPower;
- **compliance —** CitiPower has many and varying regulations, laws, guidelines and specifications that must be adhered to within its business. Many of these rules and regulation changes have a direct impact to its IT systems. Functional and process changes are required to meet changing needs. During the 2011–2015 regulatory control period CitiPower

The CitiPower and Powercor 'outages' app provides details on unplanned outages to customers



Source: CitiPower

addressed a number of compliance changes, including: annual updates to business to business (**B2B**) systems to meet AEMO requirements, as well as changes to the superannuation, payroll and the incident management system to achieve compliance; and

- **smarter network —** CitiPower has also continued to invest in significant programs to build upon the functionalities of the AMI smart meters to move towards a smarter network. CitiPower has delivered network management system (**DMS**) which provides real time network schematics for improved operational switching, patching and network utilisation, switching register application to manage planned works. In addition the following programs were undertaken in the 2011-2015 regulatory control period as discussed below.

Table 7.3 Completed smarter networks initiatives

Initiative	Brief Description
Meter Outage Notification (**MON**)	Use outage data provided by the AMI meters in an intelligent process to generate meaningful notifications to systems that are used to coordinate response to the outages
Distribution Transformer Monitoring	Access to Distribution Transformer interval data and customer interval data linked to a specific asset to support asset management and protection against theft.
Power Flow Analysis	Migration of power flow data from multiple sources into the DMS to allow for distribution network modelling based on realtime SCADA values
Proactive Voltage Monitoring	Voltage polling tool used by the network quality team to investigate Voltage anomalies remotely. Avoided cost associated to operational impact of solar installations
AMI Safety Reporting	Utilise AMI data to identify safety concerns in the network. Improved safety outcomes for customers and staff
Home area networks / in home displays	Trial in approximately 1,000 homes installing in-home display units bound to CitiPower's AMI smart meters via the establishment of an authorised Home Area Network (HAN).

Source: Capgemini, *Networks for the future – ICT roadmap*, December 2014, pp. 18-19.

Impact of AMI

During the 2011–2015 regulatory control period CitiPower has been committed to the full development, implementation and operational support of IT systems to enable the smart meter deployment program, which has required a re-balancing of resources between AMI and SCS business activities.

While CitiPower has delivered many successful initiatives, overall it has underspent the AER's IT and communications SCS allowance by 31 per cent.

As noted in the ESC Compliance with AMI Regulatory Obligations report CitiPower achieved 97 per cent of its overall AMI rollout target, and had visited 99 per cent of prescribed customer sites to try and install an AMI meter[94]. In addition to this the audit confirmed that the technology selected and installed by CitiPower met 100 per cent of the requirements of the Minimum AMI Functionality Specification and that CitiPower met all three performance standards for remote reading of AMI meter data, and could remotely connect and disconnect a customer's electricity supply.

The system implementation to support the smart meter program consisted of two components:

- the development and implementation of systems to support the deployment and commissioning of smart meters; and
- the development and implementation of systems to communicate with the deployed meters, collect meter readings, enhanced billing and dispute management process, enhance network management process to cope with interval meter volumes, distribute the meter data to market, respond to market transactions and automate previously manual functions such as de-energisation.

The deployment of smart meters involved the creation of a rollout specific Works Management System (**WMS**). The WMS automated the scheduling and allocation of jobs to the field mobility devices allowed field personnel to install smart meters. The closure of each job was notified back through WMS to CIS-OV via the integration layer. Any exceptions were handled within a customised workbench that allowed dedicated scheduling staff to expedite the resolution of issues and complete the smart meter installation.

Other components of the deployment phase included development of customer portals to support scheduling of installation appointments, enhancements to logistics systems, enhancements to support market conversion of meters from manually to remotely read.

The second component of the program, which supports the ongoing operation of the metering required the introduction of key systems such as:

- UtilityIQ to capture smart meter data, which ultimately replaced the multi-vendor remote station (**MVRS**) and multi-vendor interval data processing (**MV90**) systems which had been used to capture data from the old hand-held devices used by manual meter readers for the old type 5 and type 6 meters; and
- Itron Enterprise Edition (**IEE**), which replaced the existing MDM and NTMS systems. This application required significant enhancement to support Australian Market rules and AMI specified service levels, as well as the complex billing aggregation requirements of interval meters.

In addition to the deployment of key systems, significant investment was required to the billing and reporting environments to operate in an interval meter environment, along with integration effort to incorporate these systems into the overall IT architecture.

The vast data volumes increases associated with smart meter operation, coupled with the tight service level obligations for delivery of data to the market and retailers necessitated investment in scalable storage and processing infrastructure architectures well in excess of what was required to support an accumulation meter environment.

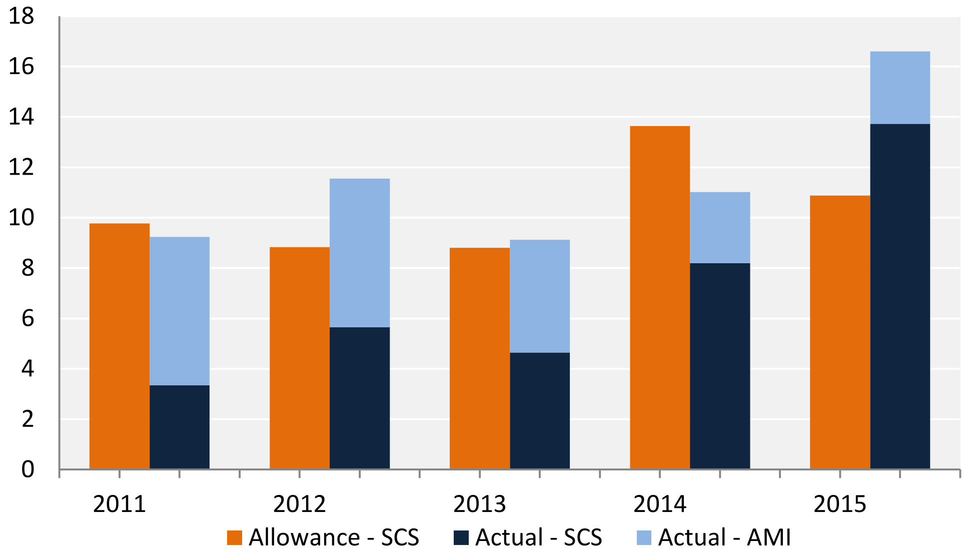
These systems and infrastructure will require continued investment to support their ongoing operation following the expiry of the specific regulatory instrument, and forms part of CitiPower's

[94] ESC, *Compliance with AMI Regulatory Obligations as at 31 December 2013*, October 2014, p. 14.

standard control submission for this period. UIQ and its associated infrastructure and security will remain as part of metering expenditure.

The scale of the AMI program and its impact of CitiPower's overall IT deliverables for the 2011-2015 regulatory control period is seen in figure 7.8.

Figure 7.8 Expenditure 2011-2015 IT (dollars million, 2015)



Source: CitiPower

7.4 Forecast expenditure

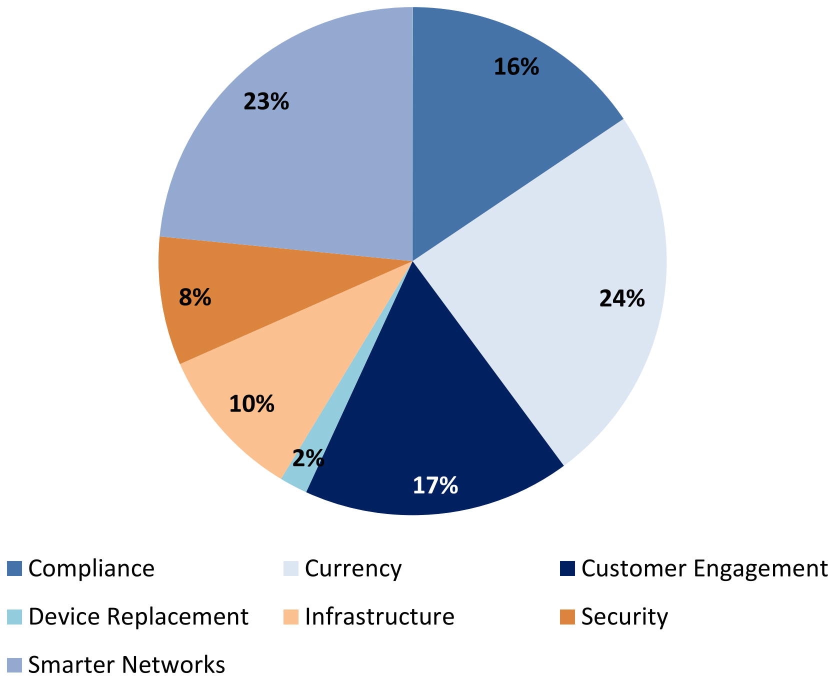
For the 2016–2020 regulatory control period, CitiPower requires a 128 per cent increase in IT and communications expenditure compared to the 2010-2015 standard control (**SCS**) allowance. This investment will enable CitiPower to efficiently maintain its industry recognised high level of service delivery to all stakeholders and will ensure that prudent investment is made in innovative solutions to meet the ever evolving customer need.

The expenditure forecast is underpinned by the following program of work where CitiPower needs to:

- manage upgrade and refresh lifecycles of core IT systems, applications and hardware;
- mitigate the evolving sophistication of security risks to the IT and communications networks;
- ensure market, regulatory and legal compliance, particularly the AER's existing, new and proposed RIN reporting requirements (which provide valuable information that allows the AER to measure CitiPower's high level of service delivery and efficiency) and facilitate Power of Choice for its customers; and
- continue to build upon the strong foundation that delivers a network of the future and empowers customer choice.

CitiPower has allocated each project into streams which align with the service delivery categories in the IT strategic plan, and which represent the top technological priorities of the business.

Figure 7.9 Forecast expenditure by IT investments stream



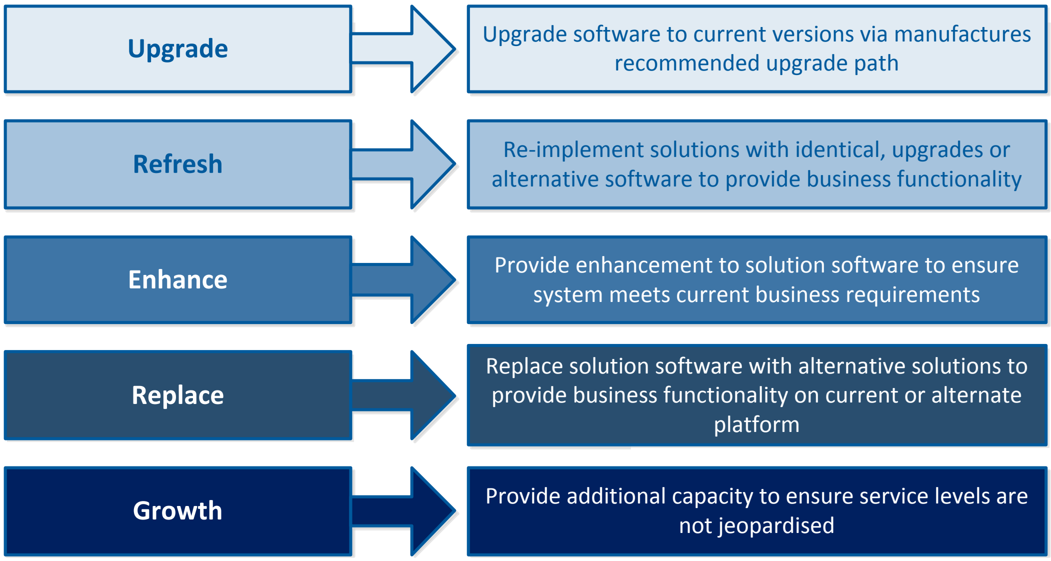
Source: CitiPower

The expenditure in each investment stream is discussed below.

7.4.1 Currency

CitiPower has over 50 systems and applications that it needs to maintain to support the operations of the business. Each of the systems must be maintained, upgraded and/or refreshed to ensure that the system remain current and able to perform its required functions. This is shown in figure 7.10.

Figure 7.10 System lifecycle considerations that influence currency investment



Source: CitiPower

In addition, IT software must be enhanced to meet new or changed business requirements, or replaced where it is no longer a suitable solution. Increases in data volumes or transactions can also result in the need to increase the processing capacity of the system, and are influenced by a number of considerations, including:

- resource utilisation — monitoring, analysing, tuning, and implementing necessary changes in resource utilisation;
- demand management — managing demand for computing resources in line with business priorities;
- system performance — modelling to simulate infrastructure performance and understand future resource needs;
- application sizing — application sizing to ensure required service levels can be met; and
- storage capacity — ensuring storage capacity is adequate to meet immediate and future needs .

Many of the key operational systems are supported by a third party vendor, these must be regularly upgraded and/or refreshed to ensure that the vendor support and maintenance contract remains valid. This includes maintaining the installed version within the acceptable range allowed by the vendor and that adequate capacity and functionality is provided to meet current and future business requirements.

CitiPower has reviewed its suite of IT and communications systems to forecast the expenditure required to maintain the range of existing systems, including:

- Oracle Fusion Utility Service Bus (**USB**) which is a system integration and business process orchestration;
- SAP which covers a range of functions including asset management, works management, materials and logistics, human resources and finance;
- PowerOn Fusion which undertakes outage management, SCADA management and other functions; and
- IEE, MTS and other systems.

Maintaining the currency of these systems is imperative to allow CitiPower to continue to provide fully supported systems that underpin the operation of the network.

7.4.2 Smarter networks

CitiPower continues to build upon the foundations provided by the deployment of smart meters by utilising their enhanced capabilities and functionality. The smarter grid transformation is a long journey from the traditional (analogue world) to a smart grid (an intelligent and responsive network) where information and data flows enable service providers to support the choices that customers make, per figure 7.11.

Figure 7.11 Smart grid transformation

	Traditional Grid	Smart Grid
Communications	One-way, delayed	Two-way, real-time
Customer interaction	Limited	Extensive
Metering	Electromechanical	Digital
Operation	Manual equipment checks maintenance	Remote monitoring, predictive, time-based maintenance
Generation	Centralised	Centralised and distributed
Power flow control	Limited	Comprehensive, automated
Reliability	Prone to failures and cascading outages; essentially reactive	Automated, proactive protection; prevents outages before they start
Restoration	Manual	Self-healing
System Topology	Radial; generally one-way power flow	Network; multiple power flow pathways

Source: Capgemini, *Networks for the future – ICT roadmap*, December 2014, p. 18.

During the 2016–2020 regulatory control period, CitiPower will continue to move towards a 'network of the future'. The smarter grid will change the way that CitiPower generates data, presents information, makes decisions, executes work and relates to customers. Customers will also benefit from improved quality of electricity supply, and better information and options for how they interact and utilise the network.

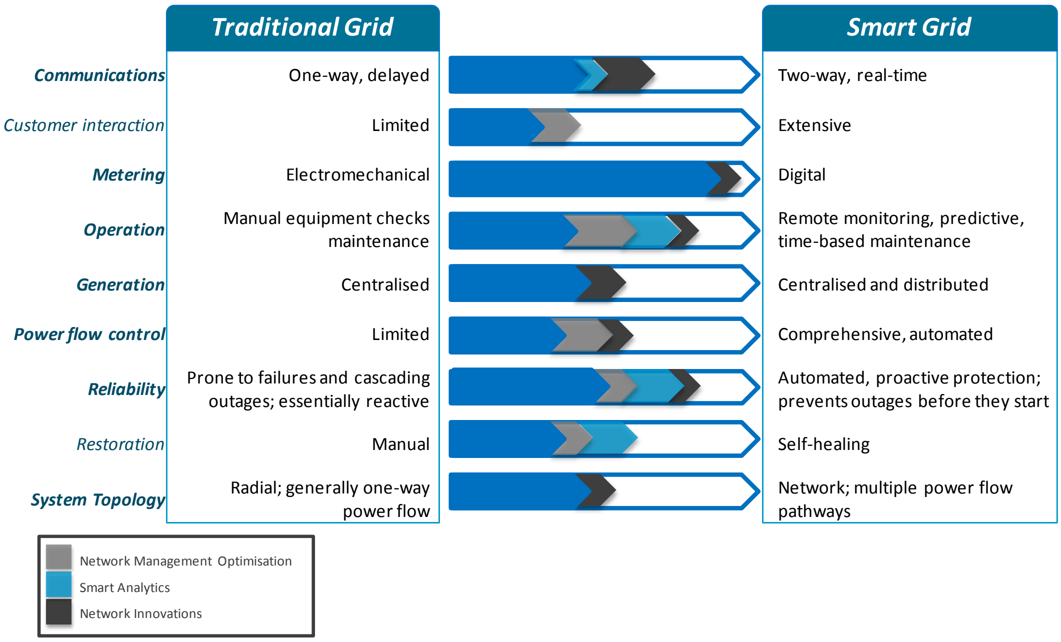
Capgemini has prepared a roadmap for CitiPower to continue on its journey towards a smarter grid. The roadmap sets out the required investment to enable improved network management and delivery of new services to customers, comprising three key initiatives:[95]

- **network management optimisation** — the aim of this initiative is to optimise the current multiple existing Information Technology/Operational Technology (**IT/OT**) systems that need to be integrated into the smart grid solution. This initiative will deliver efficiencies and benefits by converging business resources, processes and IT systems across the network;
- **smart analytics** — this initiative is focused on managing the 'explosion of data', which is a consequence of the smart meter implementation. In order to make the grid smarter, this stream will undertake a number of programs to collect, process, store and exploit this data; and
- **network innovation** — the network innovation initiative is focused in the technology innovation that can help deliver benefits to consumers by enhancing efficiency in network operations.

These investments will progress CitiPower along the path to a smarter grid, as shown in figure 7.12.

[95] Capgemini, *Networks for the future – ICT roadmap*, December 2014, pp. 5-6.

Figure 7.12 Capabilities delivered through investment in a smarter grid



Source: Capgemini, *Networks for the future – ICT roadmap*, December 2014, p. 30.

Customers have strongly supported CitiPower's transition to a smarter grid through the stakeholder engagement program. The above investment will assist in meeting customer expectations for better network management and optimisation, as well as facilitating greater opportunities for customer interaction and control.

7.4.3 Customer engagement

The customer engagement stream incorporates CitiPower's response to ongoing changes and demands from its customers for greater access and greater choice in electricity services.

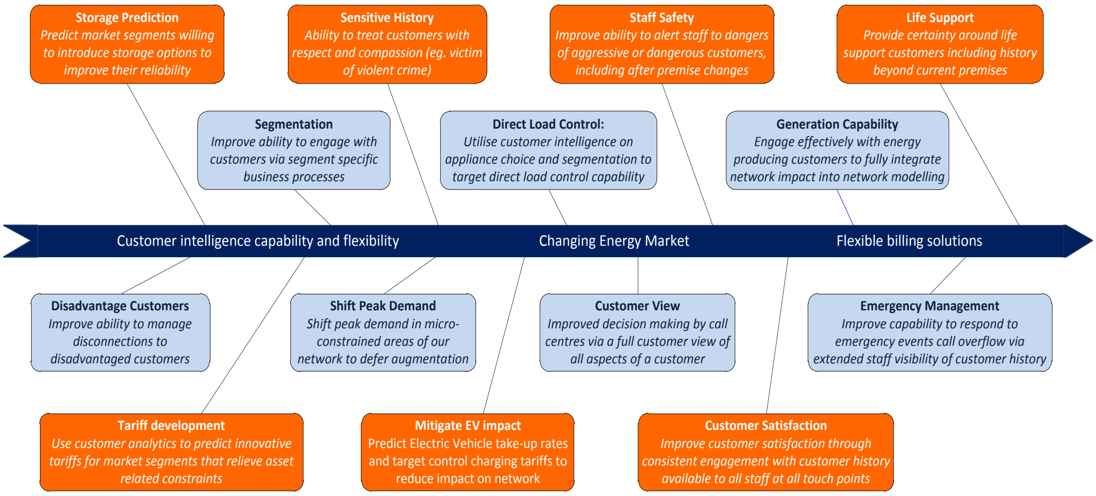
Market forces are shifting the traditional linear energy supply chain to a contemporary model where consumers become producers (i.e. prosumers) and distributors become enablers of energy solutions. In response to these industry forces, energy market and industry changes are being progressed by regulators to increase innovative participation by customers in the market.

To meet the changing need of its customer, and to comply with the regulatory changes including those associated with the AEMC's Power of Choice review, CitiPower needs to be able to meet the following requirements:

- to respond effectively to the changing energy market, a customer intelligence capability is required to more effectively engage and influence customer behaviour;
- to respond to the changing market, the capability to implement flexible, innovative and dynamic tariffs requires a modern billing system that can evolve with the industry;
- to enable customer access to energy data and encourage informed consumer choice and participation, to develop a suite of customer enablement capabilities; and
- to address the challenges of the increasing complexity of customer interactions as the market evolves, driving the need to move from National Mater Identified (NMI) centric engagement to multi-faceted customer and provider view.

Figure 7.13 depicts the factors that are driving the changes in the energy market, and how CitiPower will meet those changes.

Figure 7.13 The changing energy market



Source: CitiPower

The current billing system cannot meet emerging market requirements and will require significant modification on a high risk outdated platform. Deloitte Access Economics noted that: [96]

> *…anticipated industry and regulatory change and expected to have significant implications for billing and customer management functions.*

CitiPower will implement a new Customer Relationship Management (**CRM**) capability and flexible billing system through a program of work that will replace the current CIS OV billing system and provide customers greater access to their energy information allowing them to make informed choices. This is required to manage the increasing complexity of the direct customer relationship and emerging customer billing requirements.[97] It will also involve system integration, reporting capability and data migration.

CitiPower engaged Capgemini to undertake a scan of the CRM and billing systems in the market that would meet its internal customer requirements, as well as the anticipated future regulatory and market changes. Capgemini recommended SAP ISU billing system together with a cloud-based CRM managed by Salesforce [98] as a sound basis to meet these requirements.

In addition, Deloitte Access Economics (**DAE**) has identified and calculated the benefits to customers of a new billing and CRM system and compared it to the Capgemini costs. Customers will benefit from the investment in a new system as a result of:

- the ability for us to implement new tariff options that help lower peak demand and thus reducing network investment;
- costs that CitiPower would avoid from upgrading the existing system; and

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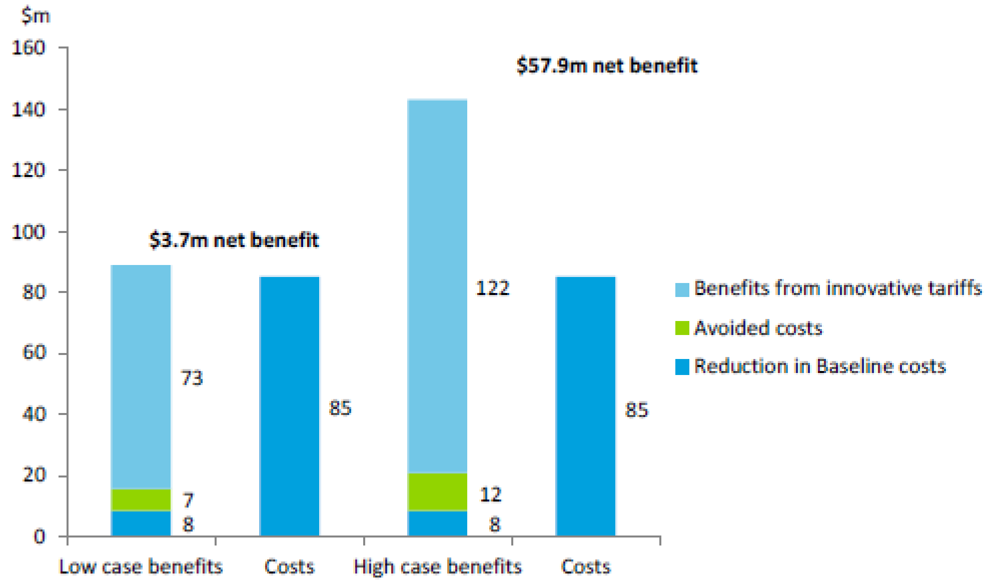
96 Deloitte Access Economics, *CitiPower and Powercor- Investing in a new billing and customer relationship management system*, December 2014, p. 10.

97 CitiPower and Powercor, *Business case – CRM and billing system replacement*, February 2015.

98 Capgemini, *CRM and Billing Market Scan – Final Report*, 27 June 2014.

- reducing the costs to operate the existing system.

Figure 7.14 Net economic from investing in a new CRM and billing system



Source: DAE, *Investing in a new billing and customer relationship management system*, 16 December 2014, p. 4.

Overall, DAE found the there is a net benefit to customers of between $3.7 million and $57.9 million if CitiPower and Powercor invest in a new CRM and billing system.

Take-up of innovative tariff offers

In September 2014, Nature undertook a survey of 800 CitiPower customers to understand the take-up of innovative tariff offers, namely:

- peak time rebates; and
- direct load control on air-conditioners or pool pumps.

CitiPower would be able to take advantage of the deployment of smart meters to implement these innovative tariff offers, which would deliver benefits by reducing consumption of electricity at peak periods — thus reducing peak network demand and consequently the need for network investment.

The survey response for peak time rebates was very positive, with 75 per cent of CitiPower customers willing to make genuine sacrifices to their comfort and reduce their energy usage for two hours per day when the temperature is over 38 degrees, in return for a cash rebate.[99]

Turning off the air-conditioner was the second most preferred option to save energy to obtain the cash rebate.

For those customers with either a non-evaporative air-conditioner or a pool pump, then 36 per cent of customers surveyed were willing to receive a rebate in return for CitiPower remotely controlling the equipment, i.e. direct load control. This would involve CitiPower installing a controlling device in the equipment which would allow it to remotely control the air-conditioner or pool pump on the hottest seven days of the year when the temperature is over 38 degrees.[100]

For air-conditioners, CitiPower proposed turning the air-conditioner to 'fan-only' mode for five minutes every 15 minutes, for a period of two hours. For pool pumps, CitiPower proposed remotely switching off the pool pump for a two hour period.

Of all customers surveyed with either air-conditioning or pool pumps, then the following were willing to sign-up for direct load control:[101]

- 31 per cent of customers with only air-conditioning;
- 72 per cent of customers with only pool pumps; and
- 31 per cent of customers with air-conditioning and pool pumps.

CitiPower requires a new billing and customer relationship management system to implement these innovative tariff offers.

7.4.4 Compliance

The compliance stream relates to ensuring compliance with relevant financial, regulatory, statutory, and market obligations. The ability to meet compliance obligations is directly impacted by the

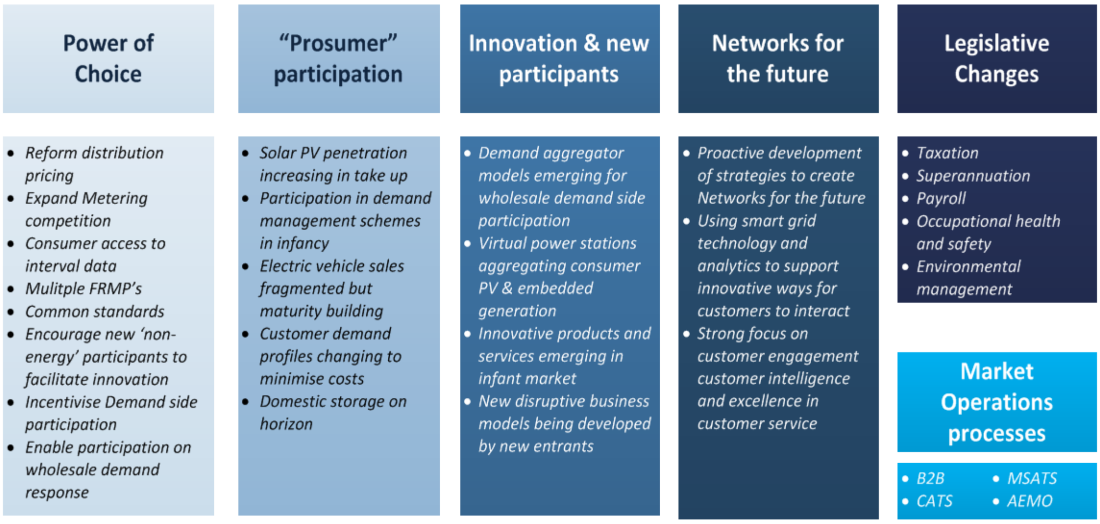
[99] Nature, *CitiPower/ Powercor Tariff Research*, 17 September 2014, p. 10. Appendix C within the report from Deloitte Access Economics, *CitiPower and Powercor- Investing in a new billing and customer relationship management system*, December 2014.

[100] Nature, *CitiPower/ Powercor Tariff Research*, 17 September 2014, p. 22. Appendix C within the report from Deloitte Access Economics, *CitiPower and Powercor- Investing in a new billing and customer relationship management system*, December 2014.

[101] Nature, *CitiPower/ Powercor Tariff Research*, 17 September 2014, p. 22. Appendix C within the report from Deloitte Access Economics, *CitiPower and Powercor- Investing in a new billing and customer relationship management system*, December 2014.

capability of the systems, processes and analytics to deliver services and information when required by the relevant law or regulatory change.

Figure 7.15 Industry compliances influences



Source: CitiPower

The stream involves meeting compliance obligations in a timely manner, taking into consideration development and implementation timelines for each of the obligations. The key drivers of the expenditure within this stream include:

- **financial compliance** — updates to the financial system, cost models and finance modules to ensure statutory compliance with taxation and accounting standards;
- **regulatory compliance** — updates to CitiPower's systems to interact with AEMO market systems and other market participants, data capture and analytics to ensure compliance with regulatory reporting obligations and National Electricity Rule updated requirements;
- **statutory compliance** — changes to systems and processes to ensure compliance with all current and future legal obligations;
- **supporting system compliance** — updates to supporting systems such as occupational health and safety, human resources, payroll to ensure compliance with national, state and local obligations; and
- **regulatory information notice (RIN)** — preparation and maintenance of information for provision to the AER relating to all RINs. Fundamental system and business process changes are required to meet the AER requirement of providing actual information for the RINs, and to improve and automate the reporting of for all RINs.

In terms of meeting the RIN requirements, KPMG has recommended that CitiPower implement an Activity Based Costing (**ABC**) approach to provide sufficient capability to deliver the reporting obligations for the Annual Reporting RIN, Fire factor RIN, Economic Benchmarking RIN and the Category Analysis RIN.[102]

KPMG noted that CitiPower's existing systems and records have been developed to meet existing management, statutory accounting and regulatory requirements. The Category Analysis RIN and

[102] KPMG, *Business Case for expenditure to meet RIN requirements*, April 2015.

Economic Benchmarking RIN prescribe new and additional reporting requirements. To date, CitiPower has achieved compliance by collecting information from outside of the existing systems and records and making estimates and judgements to classify information according to the RIN categories and definitions. However, as CitiPower will not be able to report using 'estimated' data over the 2016–2020 regulatory control period, then the ABC approach will need to be implemented.

7.4.5 Infrastructure

CitiPower seeks to prudently optimise asset lifecycles of physical infrastructure assets to ensure agreed service levels are maintained at the lowest lifecycle cost. The infrastructure steam relates to:

The infrastructure steam relates to:

- provision of adequate capacity to meet forecast volume estimates (growth);
- refreshing infrastructure components to meet technical currency requirements (currency); and
- ongoing management and maintenance of the infrastructure to meet the required Service Level requirements.

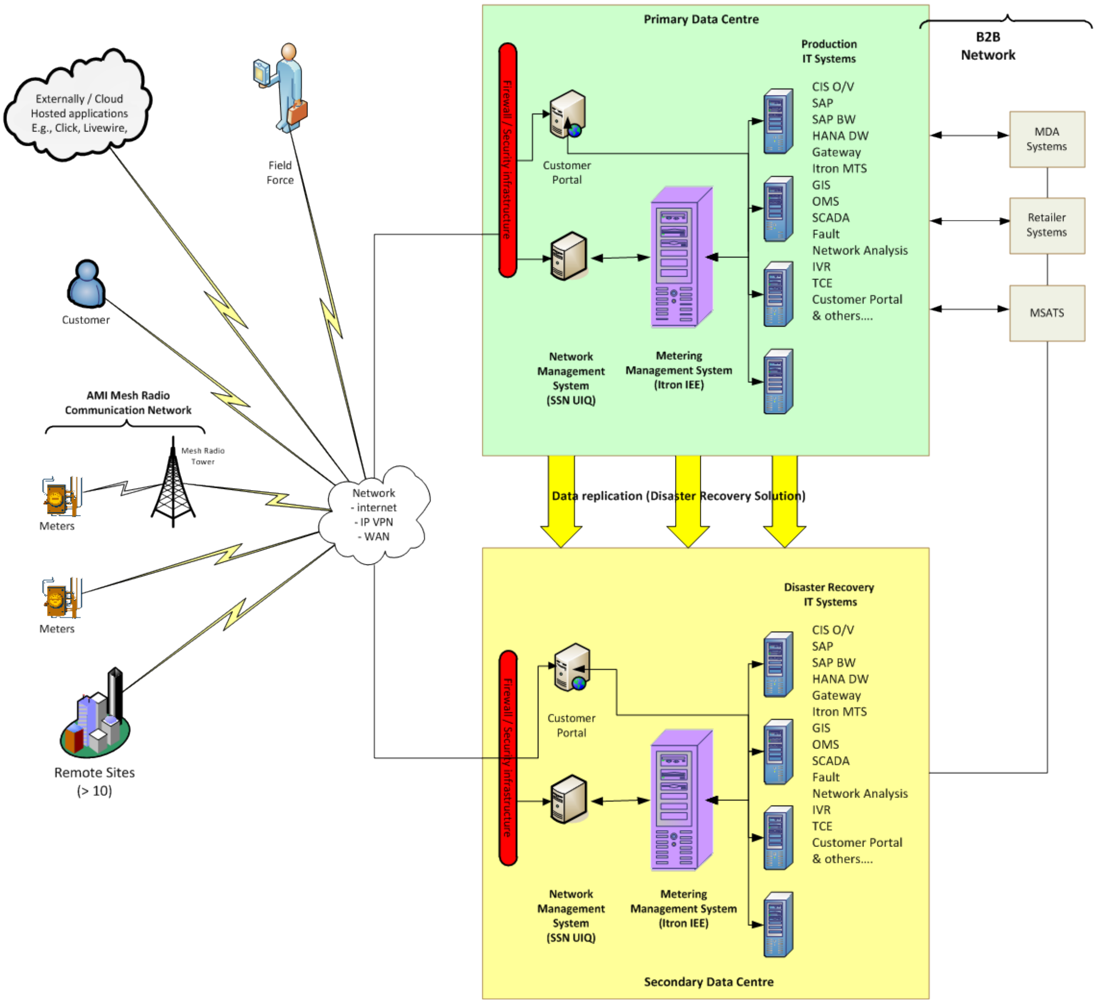
The infrastructure stream includes the following services:

- servers — Supervisory Control and Data Acquisition (**SCADA**) and corporate servers including both Windows and UNIX servers, as well as hardware and associated server software;
- storage — Storage Area Network (**SAN**) and Exadata infrastructure, including switch, array and associated infrastructure. Capacity of the storage infrastructure is actively monitored to ensure ability to meet current and future requirements;
- data warehouse — including server and storage infrastructure that provides capability for operational reporting against large volume data;
- data centre infrastructure — primary and secondary data centres and associated equipment;
- Local and Wide Area Network infrastructure (**LAN/WAN**) — switch, router and associated equipment to support LAN and WAN infrastructure across the distribution area; and
- backup — infrastructure to protect data against loss or corruption, including retention of aged backups to cater for historical data recovery.

A key element of the infrastructure expenditure is to meet requirements for disaster recovery at the primary data centre for core systems and communications in the event of equipment failure, intentional destruction or disaster at the secondary data centre, or vice versa.

CitiPower's IT infrastructure has been designed to support existing and future applications and systems, which are accessed from multiple geographical locations, as shown in figure 7.16.

Figure 7.16 CitiPower infrastructure landscape



Source: CitiPower

The core drivers for the infrastructure stream is the increasing data storage requirement for the initial build of seven years of interval meter data history, business as usual capacity growth and technical currency refreshes and backup. In reviewing CitiPower's infrastructure requirements, CSC noted that:[103]

> *A small number of meter data system related databases are responsible for 75% of storage growth.*

CitiPower makes extensive use of virtual servers, with over 670 servers in the CitiPower and Powercor infrastructure landscape. Investment in virtualisation allows CitiPower to make more effective use of its hardware resources, as well as offering rapid deployment capability, balancing of infrastructure workloads, simplified support models and enhanced availability.

Given the pace of technological advancements in infrastructure, CitiPower needs to update, replace or refresh its infrastructure to ensure that it has sufficient capacity, computing power and memory to process the increasing quantity of data related to the network. In addition, CitiPower needs to store relevant data and maintain a back-up for operational and regulatory reasons, and therefore

103 CSC, *Infrastructure requirements*, October 2014, p. 22.

will need to increase the storage and back-up infrastructure, including the data warehouse, to support the growth in data.

7.4.6 Security

Energy distribution is critical infrastructure that is at high risk of attack; prudent investment in security measures is deemed essential. To ensure that the availability of the distribution network is assured and that customers continue to receive a reliable distribution of controlled power, cyber-security threats need to be monitored, managed and mitigated.[104]

CitiPower has undertaken significant investment within the security IT capability during the current regulatory period. This has enabled CitiPower to install a secure network that manages over 323,000 smart meters as part of the AMI program. This program has resulted in an exponential growth in the number of internet capable devices that are connected to the existing IT network. Over the 2016-2020 regulatory control period, CitiPower seeks to ensure that the security of the network is maintained, proactively monitored and managed.

CitiPower commissioned the auditing services of Ernst & Young to undertake an internal audit that examined the adequacy of key policies, procedures and processes governing the SCADA IT operations. Weaknesses in the security of the SCADA IT network were identified and an action plan established to address the findings.[105]

Subsequently, an additional audit was conducted by Ernst & Young, on behalf of CitiPower, of the IT network. The audit objective was to evaluate the operating effectiveness of IT security to mitigate risks associated with an internal and external IT network attack and penetration, and develop recommendations to improve the internal controls environment. The audit report identified some critical and moderate findings that network security architecture and controls should be strengthened.[106]

Following these audits, Deloitte has, on behalf of CitiPower, reviewed the security risks facing the network. The report highlighted that the risk of cyber-attacks on Industrial Control Systems (**ICS**) is increasing each year. The most recent figures indicate that the number of cyber-security incidents across critical infrastructure has doubled. More vulnerabilities that affect ICS/SCADA infrastructure are also being identified, therefore increasing the risk of cyber-attacks being successful[107].

In addition, adequate security of corporate systems is also necessary. Confidentiality of customer information is a primary security concern as personally identifiable information is now a primary target of cyber-attackers as they can use the information to establish credentials to perpetrate fraud, rather than directly stealing funds.

As a result, a program of IT security initiatives was developed, consisting of five work streams based on best practice which aim to extend and maintain today's IT security capability: identify, detect, monitor, protect and govern. These capabilities are shown in figure 7.17.

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[104] CitiPower and Powercor, *Information Security Business Case*, January 2015, p. 4.

[105] CitiPower and Powercor, *SCADA IT Operations Internal audit report*, September 2012.

[106] CitiPower and Powercor, *IT Security – Network Security Internal audit report*, July 2013. (confidential)

[107] CitiPower and Powercor, *Information Security Business Case*, January 2015, p. 4.

Figure 7.17 IT Security capability lifecycle

Source: CitiPower and Powercor, Information Security Business Case, January 2015.

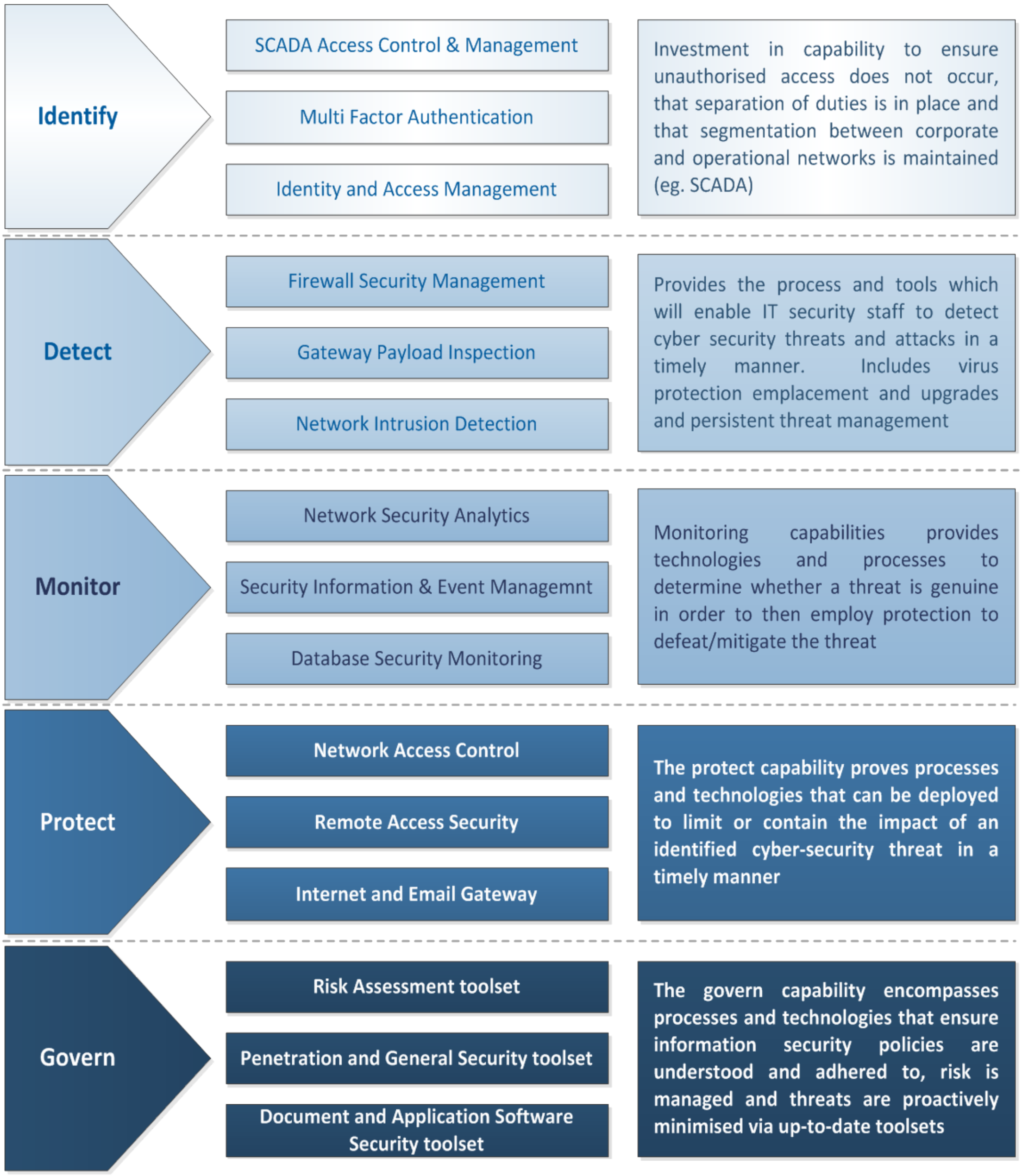
Investment in ensuring unauthorised access is prevented and the capability to detect cyber security threats in a timely manner is a prudent and critical to ensuring energy network protection. Monitoring threats to determine the actions required and deploying protection capabilities to contain the impact of identified threats are fundamental capabilities required to protect CitiPower's energy networks. Investment in the toolsets and processes to effectively govern information security ensures robust and best practice processes are in place.

The implementation of the initiatives within each capability will address the mounting security risks facing CitiPower, including the heightened risk and incidence of cyber terrorism attacks on critical infrastructure, including:

- enhancements to authentication and identify access management through introduction of multi factor authentication;
- enhancements to detection systems for network intrusion and persistent threats, including to the firewall, as well as improved virus protection and decryption;
- introduction of an internal centre of excellence to monitor and minimise risk;
- improvements to protect unauthorised devices accessing the network including remote access; and
- enhanced security associated with cloud based services, application software development, documents and other systems.

Further explanation of these initiatives is described in figure 7.18.

Figure 7.18 Security capability mapping



Source: CitiPower

The underlying principle of these initiatives is that no network is 100% secure, and resilience and planning for incidents is the most successful strategy for maintaining operations and reducing the impacts of breaches.

These initiatives help to ensure that regulatory and compliance requirements are met, such as by complying with standard ISO27002. These capabilities generally reflect the US National Institute of Standards and Technology (**NIST**) Cyber-Security Framework structure, with specific governance items for the local Australian regulatory context. The initiatives will also ensure that incidents are addressed quickly to protect customers' power supply and privacy.

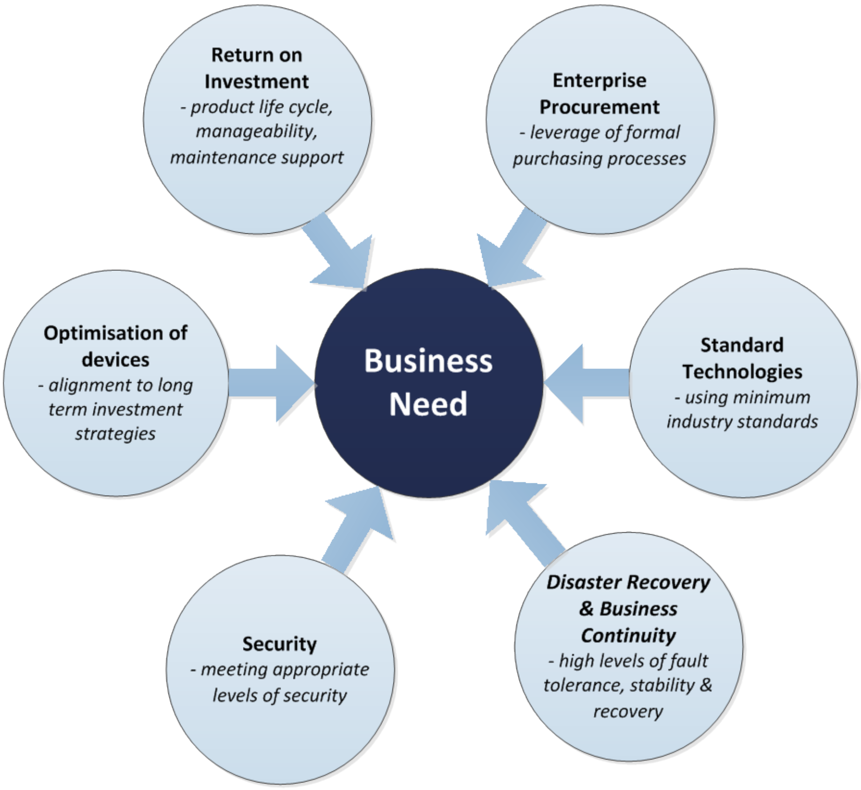
The security expenditure is also reflective of scale of security required to meet the increased access by customers to customer data; the increased information flows from and to mobile devices and the increased number of devices connected to CitiPower's networks.

7.4.7 Device replacement

Refreshing or replacing end user devices, such as computers and printers, is required to enable employee and workforce productivity and performance as the devices provide the gateway to all corporate systems.

A number of strategic principles influence device replacement decisions including long term planning for business needs, rather than individual; overall business consideration alongside technology considerations; enterprise procurement practices that drive lower cost solutions; and the adoption of uniformed technology standards to deliver best practice such as standard image, standard device, support and maintenance approaches.

Figure 7.19 Strategic device replacement considerations



Source: CitiPower

The scope of the device replacement stream includes all end user devices (**EUDs**) and Human Machine Interfaces (**HMI**'s), incorporating workstations, desktops, notebooks, printers and plotters as follows:

- **desktops** — optimising the replacement cycle of desktops and associated equipment to balance performance, reliability and cost. This will be achieved by reducing the number of desktops to move the user to device ratio closer to 1:1, as well as using bulk purchasing procurement processes to lower costs;
- **notebooks** — optimising the replacement cycle of notebooks and associated equipment to balance performance, reliability and cost. This will be achieved by reducing the number of

laptops as a result of the increased use of mobility devices, as well as the use of bulk purchasing procurement processes to lower costs;

- **printers** — optimising the replacement cycle of printers to balance performance, reliability and cost. Bulk procurement processes will be used to achieve a competitive price point;
- **plotters** — optimising the replacement cycle of plotters to balance performance, reliability and cost. Bulk procurement processes will be used to achieve a competitive price point; and
- **workstations** — optimising the replacement cycle of occupation specific workstations such as Control Room Operators to balance performance, reliability and cost. Replacement of specialist occupation specific workstations will be undertaken in accordance with the replacement cycle with individual business requirements defining the specification and performance levels required to be achieved (e.g. control room workstations running the Distribution Management System (**DMS**)/ Outage Management Systems (**OMS**) and SCADA).

It should be noted that mobility devices, including iPhones and iPads, are not included in this capital expenditure category as they will be treated as operating expenditure going forward – refer appendix G.

8 Non-network

Non-network expenditure is necessary to support the operation of the network, for example, by having the Elevated Work Platforms or 'cherry-pickers' available and in good working order so that CitiPower's crews are able to use them to help restore service to customers quickly in the event of an outage.

This section discusses CitiPower's historical and forecast non-network expenditure as well as the approach used in calculating the forecast expenditure.

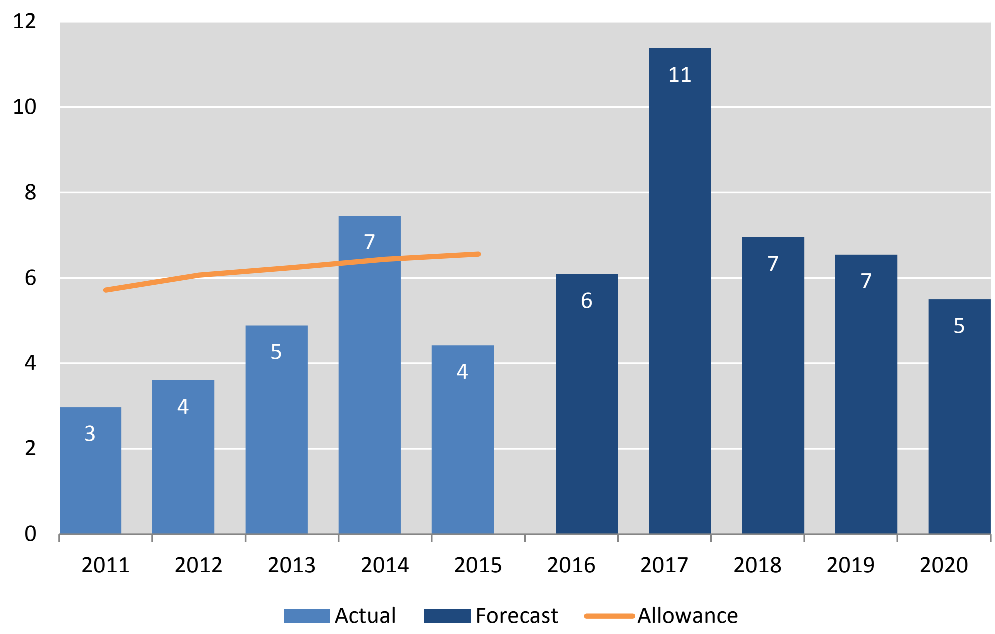
8.1 Overview

CitiPower's non-network capital expenditure includes the following cost categories:

- motor vehicles — relates to the purchase, replacement or rebuild costs associated with its light and heavy fleet of vehicles;
- property — relates to the provision of office and depot accommodation, buildings and property;
- SCADA — relates to the costs for SCADA and associated network communication and control equipment that are used to monitor and control the distribution network assets, including zone substations and feeders; and
- other — includes equity raising costs, general equipment such as miscellaneous tools and equipment.

Figure 8.1 provides an overview of historical and forecast non-network expenditure.

Figure 8.1 Non-network direct capital expenditure ($ million, 2015)[108]



Source: CitiPower
Note: excludes equity raising costs

[108] 2011 to 2014 are actual costs, 2015 to 2020 are forecast costs.

8.2 Background

This section describes the drivers and methodology for forecasting non-network capital expenditure.

8.2.1 Key drivers

Non-network capital expenditure is driven by a range of factors, which are discussed below.

Motor vehicles

The fleet comprises light or passenger fleet such as cars and utility vehicles, as well as heavy or commercial fleet, for example, cranes, elevated working platforms, trailers, crane borer and fork lifts. CitiPower's fleet expenditure is driven by:

- replacement cycle and condition of existing motor vehicles;
- new fleet associated with employee growth or network-related programs of work; and
- compliance with legislation and standards as they apply to varying categories of fleet.

Property

Property costs are driven by the need to maintain, refurbish or build new office and depot accommodation, buildings and property.

This expenditure category excludes zone substations, distribution substations and easement costs, where capital costs for those assets are captured in the augmentation or replacement categories.

SCADA

To continue to facilitate and maintain the protection and control of the network, further investment in SCADA is required to deploy communication infrastructure and up to date technology to:

- address technical obsolescence;
- address new requirements; and
- ensure compliance with relevant standards.

The SCADA category captures field devices such as remote control switches and Ethernet communications devices, as well as the fibre optic cable to provide protection signalling and connect field devices with the control room. The IT expenditure category includes costs of field based network communications systems, with the demarcation between SCADA and IT costs occurring at the SCADA front end processor.

Other

These costs relate to the costs of raising equity financing, and other non-network capital expenditure such as general equipment.

8.2.2 Forecasting methodology

The forecasting methodology for each category of non-network expenditure is set out below.

SCADA

SCADA expenditure has been forecast using a bottom-up build of requirements. This forecasting methodology is consistent with other categories of network-related expenditure, and takes into account the changing communication technologies and equipment, and the capability required by the network now and for the future.

The costs for SCADA related projects have been based on actual historical costs for similar projects where materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty borne in undertaking the projects.

Motor vehicle and other

CitiPower considers that the use of the historical average expenditure from 2011 to 2014 is appropriate for these small categories of expenditure. While there can be year-on-year variability, taking the average over a period of four years smooths out the impact of the peaks and troughs.

Property

Property expenditure has been forecast using a bottom-up build of requirements.

Equity raising costs

These costs have been forecast using the methodology set out in the AER's Post Tax Revenue Model (**PTRM**).

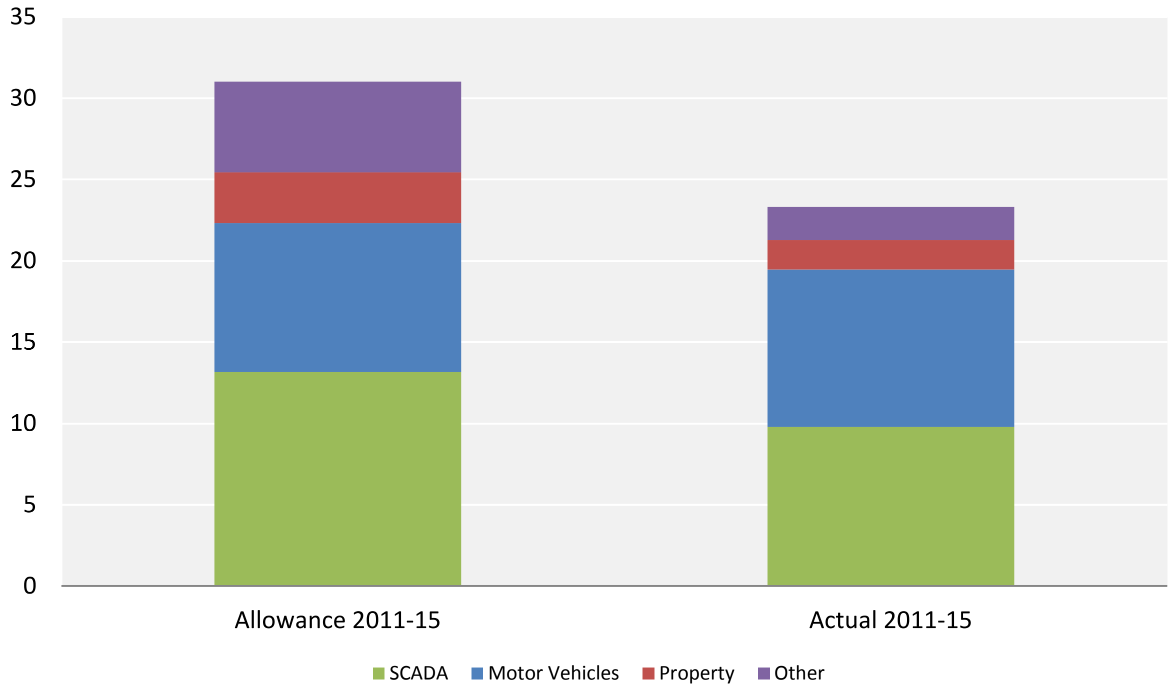
8.3 Historic spend

In the 2011–2015 regulatory control period, CitiPower has undertaken a range of activities including:

- deployment of Ethernet technology into 26 zone substations as part of the strategy to replace unsupported communications technologies in its SCADA network;
- further deployment of fibre infrastructure across the network, as well as sharing fibre infrastructure with other Victorian distributors or entering shared use agreements with fibre optic cable owners in particular cases;
- replacement of motor vehicles in accordance with the replacement cycle as well as the purchase of new fleet including a crane borer and light fleet to support operational requirements; and
- upgrade of the fleet to address changes in safety and compliance as required by Australian Standards (**AS**) or Australian Design Rules (**ADR**), including:
  - mobile cranes were upgraded to be compliant with AS1418;
  - Elevated Work Platforms continue to be upgraded to be compliant with AS2550;
  - anti-locking braking systems (**ABS**) are being installed in trailers over 4.5 tonnes, in accordance with ADR38/04;
  - trucks continue to be upgraded to meet the change in ADR80/04 to reflect Euro 6 for emissions by 2017.

Overall, CitiPower is forecast to underspend its non-network expenditure regulatory allowance in the 2011–2015 regulatory period by 25 per cent. This is shown in figure 8.2.

Figure 8.2 Historical non-network direct capital expenditure ($ million, 2015)



Source: CitiPower

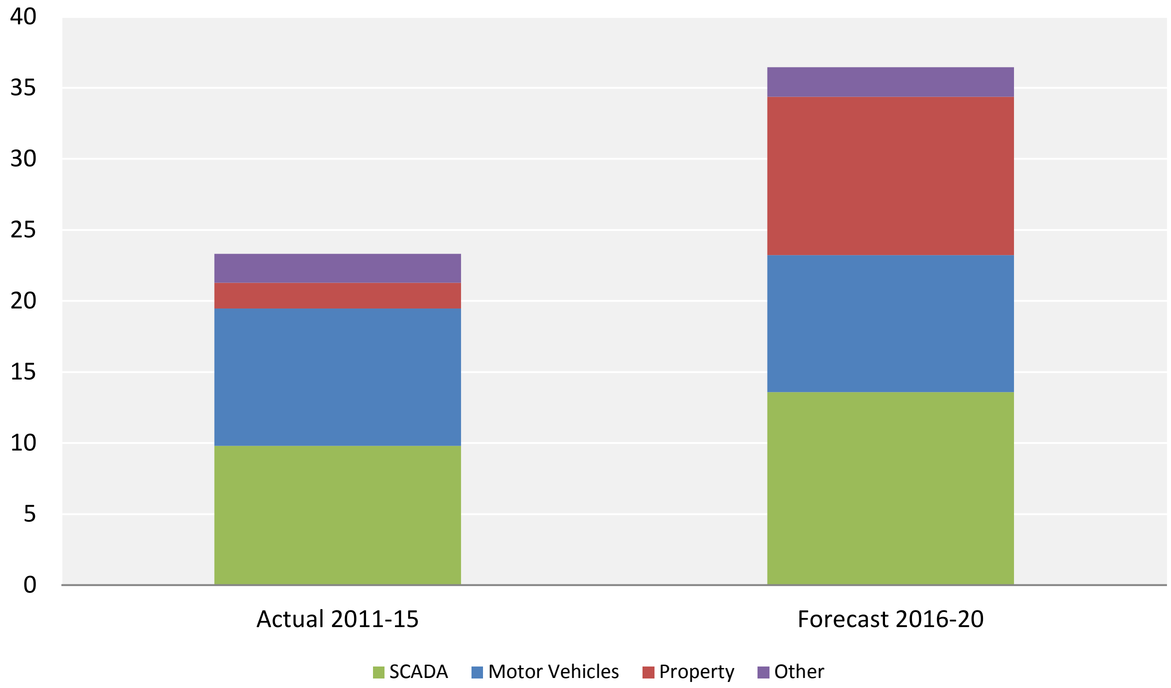
While CitiPower will underspend its overall non-network expenditure allowance, this consists of underspends and overspends in the categories, notably for:

- SCADA, an underspend of 26 per cent as a result of sharing fibre infrastructure with other Victorian distributors in cases where protection equipment crossed distributor boundaries, as well as entering into a negotiated shared use agreement with other fibre optic cable owners rather than CitiPower building its own fibre in isolated cases;
- motor vehicles, an overspend of 5 per cent. The expenditure profile for motor vehicles was uneven, reflecting the different number of vehicles purchased or replaced in a given year, as well as expenditure to address changes in safety and compliance; and
- property, where CitiPower underspent the AER allowance that was based on historical expenditure trend by around $1 million.

8.4 Forecast spend

CitiPower requires a 56 per cent increase in non-network capital expenditure compared to its actual expenditure during the 2011–2015 regulatory control period. This is shown in figure 8.3.

Figure 8.3 Forecast non-network direct capital expenditure ($ million, 2015)



Source: CitiPower
Note: excludes equity raising costs

The main driver of the forecast expenditure compared to the 2011–2015 regulatory control period is the need to undertake a redevelopment of the sole depot in the CitiPower distribution area.

SCADA

CitiPower has undertaken a bottom-up build of its forecasts for SCADA and network control equipment for the 2016–2020 regulatory control period.

The expenditure forecasts have been informed by CitiPower's strategy to develop its network communications over the longer term. UXC Consulting undertook a review of the methods and processes used by CitiPower in 2012 and developed a strategy for the best way forward to develop the communications network over the longer term. The review found, among other things, that:[109]

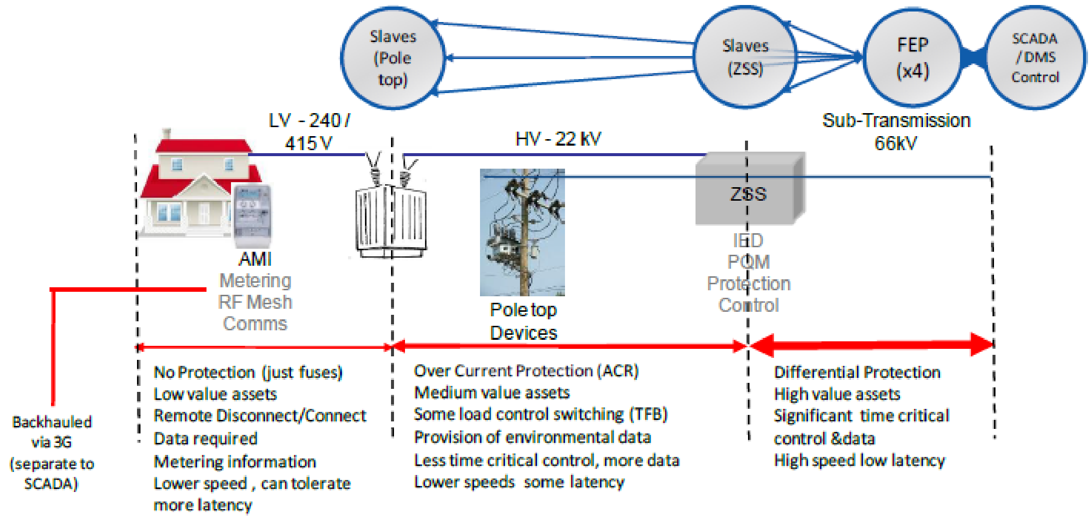
- CitiPower currently uses a significant amount of older communications technology, mainly due to the many electrical control points configured to use old proprietary bit rate limited SCADA protocols transmitted on voice frequency (**VF**) systems rather than more modern transport systems; and
- other elements within the communications network, specifically microwave and point to multipoint radio that are using VF to transmit data will need to be upgraded to enable support of SCADA Distributed Network Protocol (Level 3) (**DNP3.0**).

Figure 8.4 provides a diagrammatic view of the distribution network, including links for protection and SCADA in 2012. CitiPower uses a range of media to communicate between the control room and the remote terminal units in the field including optical fibre, 2G to 3G mobile networks, frame relay/

[109] UXC Consulting, *Distribution Network Communications Strategy CitiPower– Powercor*, December 2012, pp. 1-2.

digital subscriber line (**DSL**) fixed line services, digital and analogue radio networks, and VF over State Mobile Radio (**SMR**) and analogue supervisory cable.

Figure 8.4 Current network communications infrastructure



Source: UXC Consulting, *Distribution Network Communications Strategy CitiPower– Powercor*, December 2012, p. 17.

In its *Distribution Network Communications Strategy CitiPower – Powercor* report, UXC Consulting recommended:[110]

- continued improvement of the capability and reach of the electrical communications network, with the aim of better management of power control and monitoring devices throughout the electrical network and also support for the introduction of Distribution Automation. This will mean that CitiPower will be able to more effectively manage electrical load, especially during peak demand, and during major storm related outage events;
- upgrade all communications systems to Ethernet interfaces throughout the electrical communications network;
- apply a formal framework that will establish relevant communication requirements for device type, function and location, and enable CitiPower to choose the most suitable communications system for establishing an Ethernet connection; and
- expect communications terminal devices used in the field to need to be replaced approximately every five to ten years, that have an ability to interface with Ethernet.

As a result, CitiPower's expenditure forecast for SCADA is based on the ongoing move to Ethernet technology and replacing the unsupported technologies such as analogue radio networks and analogue supervisory cable systems over the 2016–2020 regulatory control period.

Motor vehicles

CitiPower's motor vehicle forecast for each year in the 2016–2020 regulatory control period reflects the average of costs incurred from 2011 to 2014. This expenditure will allow CitiPower to acquire, replace or rebuild its light and heavy fleet of vehicles and comply with the changes in safety and compliance obligations.

110 UXC Consulting, Distribution Network Communications Strategy CitiPower– Powercor, December 2012, p. 2.

CitiPower purchases, rather than leases, motor vehicles. This has been determined this to be most efficient method of sourcing vehicles following an internal review of the procurement strategy.

CitiPower will continue to replace its fleet in accordance with its motor vehicle replacement policy shown in table 8.1, which is drawn from its *Transport Policy Manual*. This reflects a combination of legislative requirements, manufacturers' recommendations, improvements in occupational health and safety practices and industry best practice standards. The policy is currently being reviewed, and it will be recommended that the 12 metre Elevated Work Platforms replacement cycle be changed from 15 years to ten years.

Table 8.1 Replacement cycle for motor vehicles

Vehicle	Replacement cycle
Executive Vehicles	4 years or 100,000 kms
Sedan, Station Wagons and Utilities	4 years or 120,000 kms
Vans	6 years or 140,000 kms
Four Wheel Drive – Four Cylinder	6 years or 150,000 kms
Four Wheel Drive – Six Cylinder	6 years or 200,000 kms
Four Wheel Drive – Eight Cylinder	6 years or 300,000 kms
Line construction trucks GLTs	8 years or 250,000 kms
Line construction trucks MCTs	10 years or 300,000 kms
Speciality Vehicles such as Task Trucks	*15 years or 300,000 kms
Speciality Vehicles such as Crane Borers	*10 years or 300,000 kms, replace cab chasses, complete replacement after 20 years
Speciality Vehicles Elevating Platforms	*10 year rebuild to AS2550.10, complete replacement at 15 years
Fork Lifts	10 years
Trailers	15 years
Speciality Plant, Self Loading trailers, cable recovery units	20 years

Source: CitiPower and Powercor, *Transport Policy and Procedure Manual*, 14 April 2009, p. 24.

The forecast expenditure will also allow CitiPower to complete its upgrade of Elevated Work Platforms, trailers and trucks.

Property

CitiPower's property forecast for the 2016–2020 regulatory control period reflects a bottom-up build of the expenditure requirements at the sole depot in the CitiPower distribution area in Rooney Street, Richmond.

This depot has been in operation since the 1960s State Electricity Commission of Victoria (**SECV**) era. Although structurally sound and still meeting the requirements for housing staff, plant and equipment, the ageing buildings have not been refurbished and have degraded over time. To ensure occupational health and safety requirements are maintained, and to provide a safe and productive work environment for staff, CitiPower plans to refurbish the depot.

The Rooney Street depot continues to be a strategic location for CitiPower with its central location and co-location of office and operational teams providing a convenient location to support the delivery of energy services. This project will refurbish the depot offices, undertake and structural, plumbing and electrical works to rectify defects and will remediate environmental site issues that impact on the occupation of the office depot. In addition this program will replace office furniture and the interior fit out to bring the aged current facilities up to a modern specification and will install a lift to improve access to the site.

Prior to the building being used by the SECV, the site was used as a tannery and then to manufacturer industrial chemicals and water purification equipment. The use a tannery site and chemical manufacturing plant has left an ongoing soil and groundwater contamination legacy that is being actively managed by CitiPower. However, as the refurbishment will require disturbance of the soil, the latest environmental matters must be addressed.

Other

CitiPower's forecast for general equipment and other costs for each year in the 2016–2020 regulatory control period reflects the average of costs incurred from 2011 to 2014. The exception to this is equity raising costs, which have been forecast using the methodology set out in the AER's PTRM.

8.5 Programs and projects

Table 8.2 provides an overview of the large programs of work over $2 million that CitiPower intends to undertake during the 2016-2020 regulatory control period on non-network projects.

Table 8.2 Network service material projects for non-network capital expenditure

Project name	Description	Cost ($ million, 2015)	Material project no.
Rooney Street redevelopment	Upgrade of the depot and remediation of environmental issues	11.1	PROP 19

Source: CitiPower
Note: direct costs excluding real escalation

The only material project in the non-network expenditure category is for the redevelopment of the Rooney Street depot. This project was discussed above.

9 Interaction between capital and operating expenditure forecasts

In developing the regulatory proposal, CitiPower has considered the relative costs, benefits, and risk characteristics of the various options to deliver standard control services. The preferred options, be they capital or operating in nature, are the most prudent and efficient of the alternatives available.

Further, where capital expenditure solutions have been selected, CitiPower has considered the operating expenditure implications and addressed these in the operating expenditure forecasts.

The capital expenditure for network-related programs for the 2016–2020 regulatory control period involves the addition of new assets on the network. While CitiPower will incur higher operating costs to maintain the larger network, this is reflected through the output growth escalation applied to the base year of operating expenditure. This is discussed in the operating expenditure chapter of the regulatory proposal.

The capital and operating expenditure interactions shown in table 9.1 are incremental to the output growth applied, as the step changes are not directly related to an increase in output.

Table 9.1 Interactions between capital and operating expenditure ($ millions, 2015)

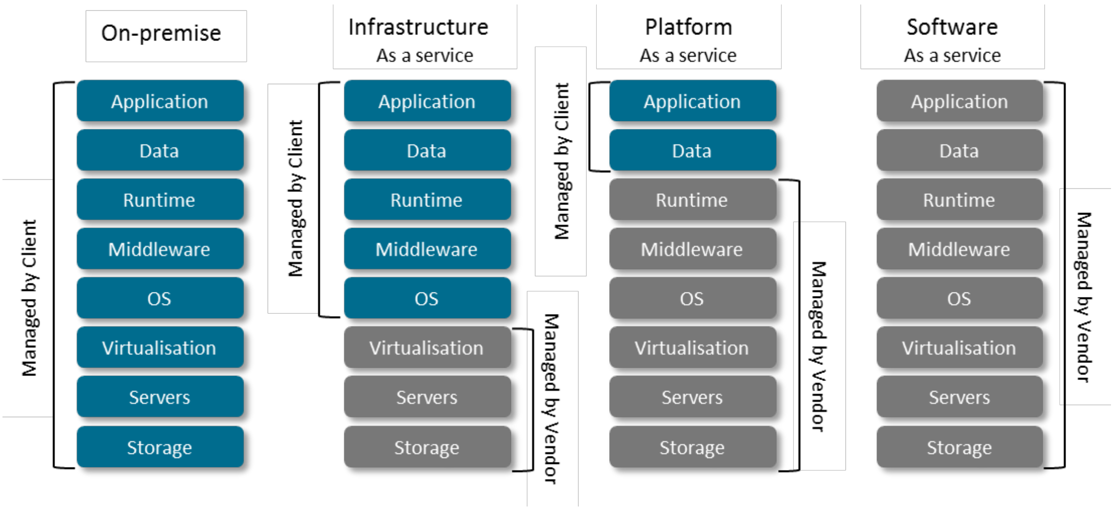
		2016	2017	2018	2019	2020	TOTAL
New billing and CRM system	Capex	6.64	5.02				11.66
	Opex			0.75	0.75	0.75	2.25
Mobility	Capex	-	-	-	-	-	0.00
	Opex	0.42	0.19	0.46	0.22	0.50	1.78

Source: CitiPower
Note: direct costs excluding real escalation

The two interactions are described in more detail below.

Firstly, as discussed in the IT chapter, CitiPower requires a new billing and CRM system. Following the Capgemini review of product offerings and costings from the market, CitiPower proposes to utilise a cloud-based solution for the CRM platform. A cloud-based solution involves a third-party vendor hosting all aspects of the service, rather than an on-premise solution where CitiPower purchases and maintains the hardware and software. The different responsibilities between and on-premise and cloud basis solution are shown in figure 9.2.

Table 9.2 Division of responsibilities for hosting options



Source: Capgemini, *CRM and Billing Market Scan – Final Report*, 27 June 2014, p. 16.

The cloud solution involves CitiPower paying a subscription fee to the third-party vendor for the use of, support and maintenance of the service. This fee is an operating expenditure payment. As CitiPower does not currently have a CRM system, this results in a step-up in expenditure.

Secondly, CitiPower's existing approach for accounting for devices such as smart phones and tablets, is a mixture of capital and operating expenditure. However, an internal review has indicated that moving to an operating expenditure only model will be more efficient. The step change, therefore, reflects the efficient substitution of capital expenditure for an operating expenditure solution.