2016–2020 Price Reset

Appendix G
Operating expenditure step changes

April 2015

CitiPower
2016–2020 Price Reset
Operating expenditure step changes

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1 Operating expenditure step changes

This appendix sets out the justification for each step change included in our operating expenditure forecast for standard control services for the 2016–2020 regulatory control period. A summary of the proposed step changes is set out in table 1.1.

Table 1.1 Operating expenditure step changes for 2016–2020 ($m, 2015)

Step change	CitiPower
Customer charter	0.2
Superannuation (accumulation members)	1.6
Monitoring IT security	2.0
Lease renewal	3.7
Mobile devices	1.8
Customer relationship management	2.2
Decommissioning zone substations	6.7
Total	**18.3**

Source: CitiPower.
Notes: Totals may not add due to rounding.

1.1 Customer charter

Table 1.2 Customer charter overview

Operating expenditure category	Network and corporate overheads
Commencement	2016
Recurrent	Once every five years

Source: CitiPower.

This step change reflects the costs of developing, producing and circulating our customer charter.

1.1.1 Driver of step change

Clause 9.1.2(b) of the Electricity Distribution Code requires us to provide a customer charter to each customer at least once every five years. The charter must summarise all current rights, entitlements and obligations of distributors and customers relating to the supply of electricity, including:[1]

- the identity of the distributor;
- the distributor's guaranteed service levels; and
- other aspects of the customer's relationship under the Electricity Distribution Code and other applicable laws and codes.

We last provided a customer charter to all our customers in 2011. Therefore, we will next need to provide a customer charter in 2016. For the following reasons, the costs incurred in developing,

[1] Clause 9.1.3 of the Electricity Distribution Code.

producing and circulating our customer charter reflect the efficient costs that a prudent operator would require to achieve the operating expenditure objectives:

- the circulation of our customer charter is a regulatory obligation. As such, not providing the charter was not considered;
- we considered a number of alternative options, but ultimately, these were not undertaken. The alternative options considered included:
    - circulate the charter electronically. A key component of our customer charter expenditure is postage costs. Our business services over 700,000 customers, and electronic circulation, therefore, would provide an effective and efficient alternative.

      At this stage, however, we do not maintain customer records that include such identifiers as email addresses. This is expected to change following the development of our new customer relationship management system (as discussed in chapter 9), but this functionality will not be available until later in the 2016–2020 regulatory control period. Changes will also be required at an industry level so that key information, such as email addresses, are provided as part of the B2B process;
    - combine our charter responsibilities with our broader stakeholder engagement program. As set out in chapter 6, our stakeholder engagement program is broad and seeks views from a wide range of stakeholders. These views are important, and the feedback received through this program has been important in the development of our operating expenditure forecasts more generally;

      The customer charter, however, is required to be provided to all our customers. In this context, we do not consider our stakeholder engagement program will adequately meet our responsibilities under the Electricity Distribution Code; and
- the forecast cost increase is not funded by other elements of our total operating expenditure allowance. This is supported by the Australian Energy Regulator's (**AER's**) benchmarking analysis, which indicates that at a total operating expenditure level, we are in the top quartile of distributors. As our costs are already efficient, absorbing future efficient cost increases driven by a regulatory obligation would not reflect the efficient and prudent costs, or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives.[2]

1.1.2 Forecasting approach

Our forecast of the costs associated with developing, producing and circulating our customer charter is set out in table 1.3.[3] The basis for this forecast is the actual expenditure incurred in developing, producing and circulating our customer charter in 2011. Customer numbers and postage costs, however, have been updated to reflect current estimates. The modelling of these forecasts are included in the attached model, *CP Customer Charter Step Change*. Consistent with the National Electricity Rules (**Rules**), this expenditure is part of a total operating expenditure forecast required to

[2] NER, cl. 6.5.6(c).

[3] The costs associated with this step change have been split between CitiPower and Powercor based on customer numbers. CitiPower is a related party, and we each hold a separate electricity distribution licence for a defined geographical electricity distribution area in Victoria. Both networks are jointly managed and operated by our own personnel and systems.

comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.[4]

Table 1.3 Customer charter—annual step change ($m, 2015)

Step change	2016	2017	2018	2019	2020	Total
Customer charter	0.2	-	-	-	-	0.2

Source: CitiPower.
Notes: Totals may not add due to rounding.

1.2 Superannuation (accumulation members)

Table 1.4 Superannuation (accumulation members) overview

Operating expenditure category	Network and corporate overheads
Commencement	2016
Recurrent	Yes

Source: CitiPower.

Our proposed superannuation (accumulation members) step change comprises two separate components—an increase in our accumulation member superannuation contributions for replacement staff, and an increase due to the superannuation guarantee levy.

1.2.1 Background

In accordance with our legal obligations, we are required to make superannuation contributions on behalf of each of our employees. This includes to both defined benefit and accumulation superannuation schemes.

A defined benefit superannuation scheme is where the employer pays an employee a set amount on retirement, typically based on the employees earnings history. The benefit, or the formula used to determine the benefit, is defined in advance. The employer, therefore, bears any investment risk. Further, under a defined benefit superannuation scheme, the employer’s liability may continue even after an employee leaves the organisation.

Our defined benefit scheme is now closed to new members.

In contrast, in an accumulation superannuation scheme, the employer makes a set contribution into an employees superannuation fund. The employee, therefore, bears the investment risk and the employers obligation ceases once an employee leaves the organisation.

All new employees in our business must be members of an accumulation superannuation scheme.

1.2.2 Driver of step change

This section discusses the drivers of the separate components of our superannuation step change.

4 NER, cl. 6.5.6(a)(2).

Superannuation payments for 'replacement' employees

On an annual basis, we engage the actuary of our superannuation fund, Mercer, to calculate the defined benefit superannuation scheme costs we recognise in our statutory accounts. For the purpose of developing our regulatory proposal, Mercer also forecast these defined benefit costs for each year of the 2016–2020 regulatory control period.

As set out in appendix F, our defined benefit superannuation scheme funding requirements are driven by a range of factors that are largely beyond our control. For this reason, we remove our actual defined benefit superannuation scheme costs from our base year operating expenditure, and replace these with Mercer's forecast of our costs for the 2016–2020 regulatory control period. This approach provides a more accurate reflection of our recurrent base year expenditure.

Mercer's forecast of our defined benefit superannuation scheme costs, however, factors in an expected decline in the number of defined benefit superannuation scheme members within our organisation over the 2016–2020 regulatory control period. That is, Mercer's forecast in 2016 is based on 97 active members of our defined benefit superannuation scheme, reducing to 70 by 2020. This decline is expected—our defined benefit scheme members represent an older demographic, and the scheme is closed to new members—but results in an underfunding of our superannuation costs (when combined with our base year adjustment approach).

Specifically, when employees who are members of our defined benefit scheme leave our organisation, new staff will be hired. These 'replacement' employees must be members of an accumulation scheme. If Mercer's forecast is used to adjust our base year expenditure, a step change is required to fund our superannuation contribution for these replacement staff. As shown in the attached model, *CP Superannuation Step Change*, the number of replacement staff is equal to the forecast decline in active members of our defined benefit superannuation fund.

For the following reasons, the superannuation payments for 'replacement' employees reflect the costs a prudent operator would require to achieve the operating expenditure objectives:

- in accordance with our legal obligations, we are required to make superannuation contributions on behalf of each of our employees. This expenditure, therefore, is consistent with the operating expenditure objectives set out in the Rules—for example, the expenditure required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;[5]

- Mercer developed their forecast under Australian Accounting Standard AASB 119. Mercer's forecasts have regard to assumed investment returns, contributions, benefit accruals, benefit payments, and other expense assumptions.[6] These assumptions reflect Mercer's views as an independent, expert actuary;

- these 'replacement' employees are not due to additional scale, or real price changes. Our superannuation contributions for these employees, therefore, will not be captured elsewhere in operating expenditure forecasts (for example, the rate of change formula);

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5 NER, cl. 6.5.6(a)(2).

6 Mercer, *Equipsuper—CitiPower and Powercor, Estimated defined benefit cost and net defined benefit asset/liability under AASB 119*, 30 March 2015.

- the magnitude of the increase in contributions for 'replacement' employees is material, and cannot be funded by other elements of our total operating expenditure allowance. For example, the AER's benchmarking analysis indicates that at a total operating expenditure level, we are in the top quartile of distributors.[7] As our costs are already efficient, absorbing future prudent and efficient cost increases would not reflect the efficient and prudent costs, or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives;[8] and

- as discussed in chapters 5 and 10, our total operating costs are efficient. These efficient costs have been achieved based on the same forecasting approach adopted for the 2016–2020 regulatory control period. Contrary to the AER's position in its recent Draft Decision for the NSW distributors, forecasting different expenditure categories using alternative approaches will not necessarily lead to a systematically biased forecast of our total operating expenditure.[9]

Superannuation guarantee levy

The Superannuation Guarantee (Administration) Act 1992 required, from 1 July 2014, that we increase our employee superannuation contributions by an increment of 25 basis points. This component of our superannuation step change reflects the six months of this increase not captured in our base year.

For the following reasons, the increase in superannuation payments for changes to the superannuation guarantee levy reflect the costs a prudent operator would require to achieve the operating expenditure objectives:

- this expenditure is consistent with the operating expenditure objectives set out in the Rules—for example, the expenditure required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;[10]

- the magnitude of the increase in contributions due to the superannuation guarantee levy is material and cannot be funded by other elements of our total operating expenditure allowance. For example, the AER's benchmarking analysis indicates that at a total operating expenditure level, we are in the top quartile of distributors.[11] As our costs are already efficient, absorbing future prudent and efficient cost increases would not reflect the efficient and prudent costs, or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives;[12] and

- as discussed in chapters 5 and 10, our total operating costs are efficient. These efficient costs have been achieved based on the same forecasting approach adopted for the 2016–2020 regulatory control period. Contrary to the AER's position in its recent Draft Decision for the NSW distributors, forecasting different expenditure categories using alternative approaches will not necessarily lead to a systematically biased forecast of our total operating expenditure.[13]

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7 Refer to chapter 5 of our regulatory proposal.

8 NER, cl. 6.5.6(c).

9 See, for example: AER, *Draft decision, Ausgrid distribution determination 2014–19*, p. 7–173.

10 NER, cl. 6.5.6(a)(2).

11 Refer to chapter 5 of our regulatory proposal.

12 NER, cl. 6.5.6(c).

13 See, for example: AER, *Draft decision, Ausgrid distribution determination 2014–19*, p. 7–173.

1.2.3 Options analysis

The nature of our superannuation obligations provides limited scope for considering alternative compliance options. For example, as discussed in section 1.2.2, we are required under the Superannuation Guarantee (Administration) Act 1992 to make specific contributions for employees into their superannuation fund.

1.2.4 Forecasting approach

As set out in section 1.2.2, we engaged the actuary of our superannuation fund, Mercer, to provide an estimate of our expected superannuation costs for the 2016–2020 regulatory control period.[14] Table 1.5 shows the breakdown of this forecast for each year of the 2016–2020 regulatory control period. The modelling for this forecast is set out in the attached model, *CP Superannuation Step Change*.

Table 1.5 Superannuation (accumulation members)—annual step change ($m, 2015)

Step change	2016	2017	2018	2019	2020	Total
Replacement employees	0.2	0.2	0.3	0.4	0.5	1.6
Superannuation guarantee levy	0.0	0.0	0.0	0.0	0.0	0.1
Total	**0.2**	**0.3**	**0.3**	**0.4**	**0.5**	**1.6**

Source: CitiPower.
Notes: Totals may not add due to rounding.

1.3 Monitoring IT security

Table 1.6 Monitoring IT security overview

Operating expenditure category	Network and corporate overheads
Commencement	2015
Recurrent	Yes

Source: CitiPower.

This step change reflects the prudent and efficient costs of monitoring our IT system alerts.

1.3.1 Background

The maintenance and operation of our distribution network is driven by three critical networks:

- Supervisory Control and Data Acquisition (**SCADA**)—this network supports the collection of data from various facilities forming part of the distribution network, as well as sending certain control instructions;
- Advanced Metering Infrastructure (**AMI**)—this network enables communication between our smart meters, and includes our AMI mesh—a wireless network designed to reduce communication faults at any single point of failure; and
- corporate IT networks—this network supports our general business operations.

[14] Mercer, *Equipsuper—CitiPower and Powercor, Estimated defined benefit cost and net defined benefit asset/liability under AASB 119*, 30 March 2015.

As set out in the attached report, *CitiPower and Powercor Australia: Information Security Business Case*, the IT security environment supporting these networks is constantly evolving. In particular, system breaches have become a growing threat. Managing these threats requires a proactive IT security program. Our program is based around six capability streams, as shown in figure 1:

Figure 1 IT security capability lifecycle

Source: CitiPower.

Our capital expenditure forecast for the 2016–2020 regulatory control period reflects expenditure driven by the Identify, Detect, Monitor, Protect and Govern categories. The increasing prevalence and potential impact of system threats is also increasing the Operate category. This includes a step change for the 2016–2020 regulatory control period for monitoring our IT networks on a 24 hour basis.

1.3.2 Driver of step change

The driver of this step change is supported by the attached report, *CitiPower and Powercor Australia: Information Security Business Case*. This attachment details the interrelationships and dependencies that exist in a robust and integrated security framework. Notably, the ability to identify and detect security threats must be coupled with the ability to respond to system breaches.

Due to their high profile and potential impact, our IT and operating networks may be the target of individuals or organisations seeking to cause disruption to the electricity network, alter meter readings, and/or access confidential corporate or customer information. Our current IT systems raise alerts for various security threats, and these alerts require human intervention to determine the appropriate response. This includes escalating the alert where appropriate.

Active monitoring of these alerts, however, currently only occurs during business hours. Therefore, if an alert is received outside of business hours, it will only be actioned the following business day. This creates a window for cyber security breaches to occur without an appropriate response.

As technology has matured, and greater information concerning the prevalence of these risks has become apparent, it is clear that our existing monitoring approach is no longer sustainable. This is consistent with the paradigm shift in the IT security industry, where proactive and strategic planning of security capabilities are now supported. For the following reasons, therefore, engaging an external service provider to monitor our IT security systems on a 24 hour basis reflects the prudent and efficient costs of achieving the operating expenditure objectives:

- the prevalence and risk of cyber attacks has increased:
  - in March 2015, the Science and Technology Select Committee (**STSC**) published their report on the resilience of the electricity system in the UK. In their report, the STSC stated the following:[15]

    > *The threats posed to critical national infrastructure from terrorism, both 'conventional' and cyber, are significant, and in respect of the latter, it is clear that this relatively novel threat will be a key preoccupation in the coming decades …*
    >
    > *The risk of breaches to cyber security are real and will continue to evolve as the electricity system becomes ever more dependent on ICT [information and communications technologies]. While we note that the Government is taking action in this area, we are concerned about the threat in the medium term as the electricity system becomes increasingly reliant on fast communication, on data, and dependent on automation. As new threats are identified so the Government must work ever more closely with stakeholders and provide appropriate funding for efforts to combat cyber-attack. The Government must ensure that cyber security factors are embedded at the earliest stages of electricity system design.*
  - in 2012, the Industrial Control Systems Cyber Emergency Response Team (**ICS-CERT**) reported that 41 per cent of cyber security incidents across critical infrastructure sectors involved the energy sector, particularly electricity;[16]
  - vulnerabilities that affect industrial control and SCADA infrastructure are continually being identified. As ICS–CERT set out, internet facing devices have become a serious concern over the past few years with remote access demands giving way to insecure or vulnerable configurations. In particular, 87 per cent of the vulnerabilities reported in 2013 for industrial control and SCADA systems were remotely exploitable—that is, the system could be compromised over a network without physical access required;[17]
  - the tools required to undertake a cyber attack are now readily available. Coupled with an expanding body of public knowledge on vulnerable infrastructure, this lowers the level of knowledge required to successfully locate internet facing control systems;[18] and
  - the STCS and ICS–CERT reports are not specific to the Australian context. The capacity and propensity for cyber attacks, however, is a global issue that is not driven by proximity or country specific environmental factors;

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[15] Science and Technology Select Committee, *The resilience of the electricity system*, 12 March 2015, pp. 43–46.

[16] Industrial Control Systems Cyber Emergency Response Team, *ICS-CERT Monitor (Oct-Dec 2012)*, USA, 2012.

[17] Industrial Control Systems Cyber Emergency Response Team, *ICS-CERT Monitor (Jan-Apr 2014)*, USA, 2014.

[18] Industrial Control Systems Cyber Emergency Response Team, *ICS-CERT Monitor (Jan-Apr 2014)*, USA, 2014.

- our exposure to cyber attacks has increased:
    - the growing convergence of our IT and operating systems has increased our exposure to a cyber security event. For example, we now access our SCADA system through our general IT framework, whereas it was previously accessible only through a direct, isolated network. Similarly, the logical conversion of our advanced metering infrastructure has widened the range of potential network gateways;
    - in addition to threats to industrial control and SCADA systems, our corporate IT network is exposed to cyber attacks. Confidentiality of customer information, for example, is a primary security concern as communication between businesses and consumers becomes more digital via online and mobile channels. Personally identifiable information has become a primary target of cyber attackers, as they can use the information to establish credentials to perpetrate fraud, rather than directly stealing funds. Common information stored, such as address, date of birth and other details, can all be used to complete identify verification checks by miscreants. These attacks are opportunistic and take advantage of outdated or unpatched systems and vulnerabilities;

      As set out in chapter 9 and section 1.6, this exposure will become more pronounced as greater customer information is captured and systematically stored through our new billing and customer relationship systems. The introduction of these systems follows changes to regulatory obligations regarding customer access to information about their energy consumption. Adopting a 24 hour monitoring regime is part of a prudent approach to managing these risks;
- the capacity to monitor, manage and mitigate the risk of cyber attacks has improved:
    - the market for 24 hour monitoring services is maturing. It is only recently that our incumbent IT providers have begun to offer these services at competitive rates;
    - in late 2014, our security information and event management (**SIEM**) systems became operational. The functionality of our SIEM infrastructure is still developing, but it provides a framework that facilitates effective external monitoring, management and mitigation;
- given the above, it is no longer prudent or efficient to only monitor our network during business hours. Instead, maintaining the reliability and security of our distribution system requires the ability to detect the attack, determine its methods and mitigate them to restore service, irrespective of when these attacks occur. In this context, it is notable that although the risk of cyber threats has increased gradually, the profile of costs to respond to these growing threats is stepped (and not reflected in our base year operating expenditure);
- engaging an external service provider is a lower cost option than expanding our internal IT security team, and is expected to be more effective at identifying and responding to threats. For example, developing the internal capability to monitor our IT system is forecast to require an additional nine FTE, at an expected cost in excess of $1.6 million per annum. In contrast,

outsourcing this monitoring to an external security company is expected to cost $0.8 million per annum over the 2016–2020 regulatory control period;[19]

- external security experts can spread costs across multiple industries. This also allows them to develop a broader experience of developing market threats, and corresponding monitoring techniques. It is expected this will lead to a more robust and effective monitoring program (relative to developing internal capabilities);

- in developing the forecast of costs, estimates were requested and provided by our two incumbent IT security experts that are familiar with our IT infrastructure. These security experts are independent third parties, and the competitive process is reasonably expected to lead to an efficient cost for the provision of the monitoring services;

- two further options—do nothing, and increase our IT capabilities through capital improvements—were also considered. The do nothing option was rejected as it would not allow us to prudently manage the reliability, safety and security of our distribution system. IT capital expenditure alternatives were rejected on the basis of costs to consumers. That is, the operating expenditure option of engaging an external service provider is a lower cost option, and is sufficient to prudently manage the reliability, safety and security of our distribution system;

- the magnitude of the proposed increase for IT monitoring expenditure is material and cannot be funded by other elements of our total operating expenditure allowance. For example:

  - the AER should not assume that our base year expenditure is sufficient to provide all costs necessary to maintain network security, in particular for IT security expenditure. Environmental changes in the IT security space are rapid and continual, but the costs of responding to these changes are discrete and lumpy. The advance of technology means that what may have been prudent and efficient in 2014 is not necessarily sufficient to manage risk in 2016 and beyond—that is, the costs of responding to the increased prevalence of cyber threats are not business-as-usual costs;

  - IT security expenditure is not self-financing. For example, the prudency of monitoring our network is driven by minimising potential future costs, as opposed to achieving productivity or efficiency gains that our business will benefit from. This can affect the timing of IT security expenditure, particularly where these costs are discrete and lumpy (that is, where these costs are not reflected in business-as-usual expenditure);

  - IT security requirements are not linked to specific regulatory obligations. This does not mean, however, that IT security expenditure is not prudent and efficient. Moreover, as discussed in chapter 10, the Rules do not limit step changes to changes in regulatory obligations;

  - the proposed step change reflects the incremental cost (of existing monitoring activities) above that captured by the rate of change formula and

- the AER's benchmarking analysis indicates that at a total operating expenditure level, we are in the top quartile of distributors.[20] As our costs are already efficient, absorbing future prudent and

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19 The costs associated with this step change have been split equally between Powercor and CitiPower. An equal split was applied as these costs are not driven by customer numbers.

efficient cost increases would not reflect the efficient and prudent costs, or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives.[21] As discussed in chapters 5 and 10, our total operating costs are efficient. These efficient costs have been achieved based on the same forecasting approach adopted for the 2016–2020 regulatory control period. Contrary to the AER's position in its recent Draft Decision for the NSW distributors, forecasting different expenditure categories using alternative approaches will not necessarily lead to a systematically biased forecast of our total operating expenditure.[22]

1.3.3 Forecasting approach

Our forecast for this step change is based on an estimate of costs provided by one of our incumbent IT security providers, included as confidential attachment, *Monitoring IT security price estimate*. These costs include real time threat management, managed firewall services and intrusion prevention system services.

As outlined in chapter 10 of our regulatory proposal, we are in the process of engaging an external security provider to commence 24 hour monitoring of our network by June 2015. The scope of works for 2015 reflects a 'pilot' program, with full network monitoring to occur from 2016 onwards.

Our forecast of this step change is set out in table 1.7.[23]

Table 1.7 Monitoring IT security—annual step change ($m, 2015)

Step change	2016	2017	2018	2019	2020	Total
Monitoring IT security	0.4	0.4	0.4	0.4	0.4	2.0

Source: CitiPower.
Notes: Totals may not add due to rounding.

1.4 Lease renewal

Table 1.8 Lease renewal overview

Operating expenditure category	Network and corporate overheads
Commencement	2015
Recurrent	Yes

Source: CitiPower.

In our network, there are five zone substation sites that are leased under 50 year agreements. The lease agreements for a number of these sites are due to expire (for the first time) in the 2016–2020 regulatory control period.

These lease agreements were initially entered into by the State Electricity Commission, and are unique and select in nature—that is, the leases are long-term, limited in number, and have not previously been renewed. Their renewal, therefore, is not a business-as-usual activity. This contrasts

20 Refer to chapter 5 of our regulatory proposal.

21 NER, cl. 6.5.6(c).

22 See, for example: AER, *Draft decision, Ausgrid distribution determination 2014–19*, p. 7–173.

23 The costs associated with this step change have been split equally between Powercor and CitiPower. An equal split was applied as these costs are not driven by customer numbers.

to other general lease arrangements (e.g. for general property, and/or motor vehicles), for which incremental lease renewals are common place and are reflected in our base year and rate of change calculations.

This step change reflects the total incremental costs associated with the renewal of these lease agreements. As these lease negotiations are ongoing, the details of the individual lease arrangements are set out in the confidential attachment, *Lease renewals*. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to meet or manage the expected demand for standard control services.[24]

1.4.1 Forecasting approach

This step change reflects the forecast incremental expenditure from the new lease agreements, above the corresponding expenditure incurred in 2014. These costs are summarised in table 1.9.

Table 1.9 Lease renewal—annual step change ($m, 2015)

Step change	2016	2017	2018	2019	2020	Total
Lease renewal	0.7	0.7	0.7	0.7	0.7	3.7

Source: CitiPower.
Notes: Totals may not add due to rounding.

1.5 Mobile devices

Table 1.10 Mobile devices overview

Operating expenditure category	Network and corporate overheads
Commencement	2016
Recurrent	Yes

Source: CitiPower.

This step change reflects the efficient substitution of capital expenditure for an operating expenditure solution.

1.5.1 Driver of step change

Mobile devices have become essential to the manner in which we operate our business. This includes in-situ real time data capture and access, as well as accurate and timely hazard and incident reporting. In the field, these devices have led to productivity and efficiency gains that are reflected in our base year.

Our existing approach for accounting for these devices is a mixture of capital and operating expenditure. We capitalise the costs of mobile devices and protective accessories, as well as the labour component associated with formatting and setting up these devices. The corresponding data and repair requirements are expensed.

An internal review, however, has indicated that moving to an operating expenditure only model is a more efficient alternative. In particular, mobile repayment options are now available that provide the functionality of our existing mobile devices, but without the need to purchase the device

24 NER, cl. 6.5.6(a).

outright. Although the mobile repayment option plan is more expensive than the data equivalent under the purchase option, this is offset by the savings from not purchasing the device. The net outcome is lower total expenditure.

The AER's Expenditure Forecast Assessment Guideline recognised that it may be efficient to increase operating expenditure if it reduces capital costs.[25] Similarly, the operating expenditure factors require the AER have regard to the relative prices of operating and capital inputs, and the substitution possibilities between operating and capital expenditure.[26] Given it results in net lower total expenditure, this operating expenditure reflects the efficient costs of achieving the operating expenditure objectives.

1.5.2 Forecasting approach

This step change is forecast to commence in 2016. This timing reflects the expiration of the contracts for our existing mobile devices.

Our forecasting approach for the efficient substitution of operating expenditure for capital expenditure is set out in the attached model, *CP Mobile Replacement Step Change*. The additional operating costs are summarised in table 1.11.

Table 1.11 Mobile devices—annual step change ($m, 2015)

Step change	2016	2017	2018	2019	2020	Total
Mobile devices	0.4	0.2	0.5	0.2	0.5	1.8

Source: CitiPower.
Notes: Totals may not add due to rounding.

1.6 Customer relationship management

Table 1.12 Customer relationship management overview

Operating expenditure category	Network and corporate overheads
Commencement	2018
Recurrent	Yes

Source: CitiPower.

This step change reflects the incremental impact on our operating expenditure forecasts of developing a new customer information system (**CIS**) and customer relationship management (**CRM**) system.

1.6.1 Background

Our existing billing and customer information system was developed over 15 years ago. This system records energy usage data against a national meter identifier (**NMI**).

Outside of recording energy usage against a NMI, our existing system provides very limited functionality. For example, it cannot systematically record customer name and address details. The ageing software is also no longer supported by the vendor as a commercial multi-customer product.

[25] AER, *Expenditure Forecast Assessment Guideline*, p. 72.
[26] NER, cls. 6.5.6(e)(6) and (7).

Further, on 6 November 2014, the AEMC published its final Rule Determination outlining changes to regulatory obligations regarding customer access to information about their energy consumption. The Rules include the following:

- allow customers to obtain their electricity consumption data from distributors and retailers;
- allow parties authorised by customers to also obtain their customers' electricity consumption data from distributors and retailers; and
- require distributors and retailers to comply with minimum requirements relating to the format, time frames and reasonable charges when a customer, or a party authorised by that customer, requests their electricity consumption data.

The requirements set out above cannot be efficiently met by our ageing billing system.

Our capital expenditure forecast for the 2016–2020 regulatory control period, therefore, includes a material project to develop a new CIS and CRM system. The justification for this project is set out in chapter nine. This includes the discussion of the benefits case for the new systems.

1.6.2 Driver of the step change

As set out in chapter 9, replacing our existing CIS system with a fully integrated and flexible CRM system results in increased operating expenditure for the 2016–2020 regulatory control period. The operating expenditure component comprises the incremental costs for maintaining software licences and support for the new billing system (above the costs of our existing system). It also includes cloud based subscription fees for the CRM system.

For the following reasons, we consider these costs reflect the efficient costs that a prudent operator would require to achieve the operating expenditure objectives:

- as set out in chapter 9, there is a positive benefits case for the introduction of our CIS and CRM system. This benefits case includes the forecast operating expenditure impact;
- our new CIS and CRM system will provide the framework to support compliance with the Rule changes determined by the AEMC.[27] This expenditure, therefore, is consistent with the operating expenditure objectives set out in the Rules—for example, the expenditure required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;[28]
- the Rules require the AER have regard to the relative prices of operating and capital inputs, and the substitution possibilities between operating and capital expenditure.[29] As outlined in chapter 9, and in the Deloitte report, the benefits to customers from this project are greater than the costs;

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27 For example, the system would support the introduction of multiple trading relationship (although for clarity, any associated expenditure is not included in this step change).

28 NER, cl. 6.5.6(a)(2).

29 NER, cls. 6.5.6(e)(6) and (7).

- the magnitude of the licence and support increases is material, and cannot be funded by other elements of our total operating expenditure allowance. For example:
    - in its Expenditure Forecast Assessment Guideline, the AER stated that any increase in operating expenditure driven by capital expenditure that increases output would be compensated through the rate of change formula.[30] This step change reflects the incremental operating expenditure above that compensated for in the rate of change formula;
    - the AER's benchmarking analysis indicates that at a total operating expenditure level, we are in the top quartile of distributors.[31] As our costs are already efficient, absorbing known, future prudent and efficient cost increases would not reflect a realistic expectation of the cost inputs required to achieve the operating expenditure objectives;[32] and
- access to usage data was a common theme in customer and stakeholder feedback throughout our stakeholder engagement activities.[33] The Rules require the AER to have regard to the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers identified in the course of our engagement with electricity consumers.[34]

1.6.3 Forecasting approach

Our forecasting approach for the incremental operating expenditure as a result of developing a new CIS and CRM system is set out in the attached model, *CP CRM Step Change*.[35] The additional operating costs are summarised in table 1.13.

Table 1.13 Customer relationship management—annual step change ($m, 2015)

Step change	2016	2017	2018	2019	2020	Total
Customer relationship management	-	-	0.7	0.7	0.7	2.2

Source: CitiPower.
Notes: Totals may not add due to rounding.

1.7 Decommissioning zone substations

Table 1.14 Decommissioning zone substations overview

Operating expenditure category	Maintenance
Commencement	2016
Recurrent	Partial

Source: CitiPower.

30 AER, *Expenditure Forecast Assessment Guideline*, p. 74.
31 Refer to chapter 5 of our regulatory proposal.
32 NER, cl. 6.5.6(c).
33 See, for example, chapter 6 of our regulatory proposal.
34 NER, cl. 6.5.6(e)(5A).
35 The costs associated with this step change have been split between Powercor and CitiPower based on customer numbers.

This step change is for the costs associated with decommissioning five zone substations within our network. These costs include the removal of plant and equipment, and the remediation of these sites.

1.7.1 Background

Our Capital Expenditure chapter and appendix discuss a number of material projects proposed to be undertaken during the 2016–2020 regulatory control period. Three of these projects include an operating expenditure component for the costs associated with decommissioning zone substations:

- the decommissioning of the West Melbourne Terminal Station 22kV subtransmission network;
- the Prahran zone substation offload; and
- the Waratah Place zone substation development.

A summary of these projects is provided below.

Decommissioning of the WMTS subtransmission network

The West Melbourne Terminal Station (**WMTS**) is part of the electricity transmission network owned and operated by AusNet Services. Connected to this terminal station is the 22kV subtransmission network. This network currently supplies four of our zone substations—Dock Area, Spencer Street, Laurens Street, and Bouverie Street.

The 22kV subtransmission network, as well as the four zone substations which are supplied by this network, are all reaching the end of their life. Certain parts of the subtransmission network, for example, have been in service since the 1940s. Instead of replacing the 22kV subtransmission network, however, the efficient planning approach is to transfer the load to the existing 66kV network. This approach includes the decommissioning of zone substations at Spencer Street and Laurens Street. A further zone substation, at Tavistock Place, will also be decommissioned as a result of this project.

The decommissioning of the WMTS subtransmission network is scheduled to commence in 2017. The decommissioning of the Spencer Street zone substation is expected to be completed in 2018, followed by the Tavistock Place and Laurens Street zone substations in 2019.

Prahran zone substation offload

The inner city suburbs of Prahran, Caulfield, Balaclava, South Yarra, Windsor, St Kilda and Richmond are supplied by zone substations in Toorak, Balaclava, St Kilda, Richmond and Prahran. These areas have increasing numbers of developers requesting new connections to develop large blocks and old factories into large apartment complexes. These loads are accelerating the uptake of the spare capacity in these zone substations. By 2020, the load is forecast to well exceed the capacity.

With the exception of Prahran, the above zone substations are connected to an existing 66kV subtransmission loop. Some of the lines within this loop are also currently overloaded during peak load periods.

As part of the solution to the above constraints, an upgrade of the ageing Prahran 22kV zone substation was considered. The most efficient solution, however, was to permanently offload Prahran, and move most of the load to Balaclava. This solution also includes a second subtransmission line to Toorak.

The Prahran offload project has commenced, and the zone substation at Prahran will be decommissioned in 2016.

Waratah Place zone substation redevelopment

As part of our CBD security of supply project, we are upgrading our existing switching station at Waratah Place. Upgrading this switching station (to a zone substation) facilitates the decommissioning of the nearby ageing zone substation at Russell Place. Upgrading the Waratah Place switching station and decommissioning the zone substation at Russell Place represents a more efficient solution than other alternatives, such as redeveloping both stations.

The Waratah Place zone substation redevelopment project has commenced. The decommissioning of the Russell Place zone substation will begin in 2018.

1.7.2 Driver of step change

Throughout our network, assets are maintained and replaced as required, based on their condition. Network planning may also result in some assets being decommissioned. In these circumstances, Section 98 of the Electricity Safety Act may require such assets to be removed. Specifically, the Electricity Safety Act states the following:

> *A major electricity company must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable—*
>
> (a) *the hazards and risks to the safety of any person arising from the supply network; and*
>
> (b) *the hazards and risks of damage to the property of any person arising from the supply network; and*
>
> (c) *the bushfire danger arising from the supply network.*

Prudent asset management also dictates that we remove decommissioned assets. Managing our network in this manner ensures we maintain the safety of the distribution system.[36] For example:

- each of the zone substation sites contains hazardous materials, including asbestos, in equipment insulating panels and throughout the buildings (in fire doors, barriers and internal cladding). Similarly, the major plant contains oil and other contaminants;
- the risks associated with hazardous material are actively managed while a zone substation is in operation. This is due to routine maintenance cycles, and other regular operational visits. In the absence of a routine maintenance cycle, however, these materials may become dispersed. This is particularly the case if the sites become a target for theft, vandalism and/or squatters. As outlined in discussions with the Melbourne City Council, the public safety implications of unoccupied buildings (due to squatters and unauthorised access) in the City of Melbourne are significant;[37]
- the impacts associated with the dispersion of hazardous materials may include the following:

[36] NER, cl. 6.5.6(a)(4).

[37] See, for example: Minutes from meeting with Melbourne City Council, *Management of decommissioned CitiPower zone substations within the Melbourne City Council area*, 9 April 2015.

  - the dispersion of asbestos can cause major health risks. When disturbed, asbestos may produce a dust containing asbestos fibres. Breathing these fibres into the lungs can cause a range of health problems including pleural plaques, asbestosis, lung cancer and mesothelioma. The potential risk associated with asbestos dispersion is heightened by the proximity of the zone substations to public facilities, such as the public housing buildings in Prahran;

  - the potential dispersion of oil from oil-filled plant and equipment represents a environmental and fire hazard. The Environment Protection Act, administered by the Environmental Protection Authority (**EPA**), contains a number of provisions relevant to contamination of land. This includes the transport and disposal of contaminants. In particular, section 45 makes it an offence to pollute land and section 57 provides for environmental audits by accredited auditors; and

  - the dispersion of plant and equipment more generally may result in exposed wires that present an electrocution risk. To mitigate this risk, the decommissioning process would seek to disconnect supply and remove exposed wiring and hazards. Utilities would also be disconnected.

For the following reasons, therefore, the costs forecast to be incurred to remove plant and equipment, and remediate the sites for the five zone substations reflect the prudent and efficient costs of achieving the operating expenditure objectives:

- as part of our ongoing stakeholder engagement program, we met with representatives from the Melbourne City Council and the City of Stonnington. In particular, representatives from the Melbourne City Council outlined the significant public safety implications of unoccupied buildings (due to squatters and unauthorised access) in the City of Melbourne. This extends to the risk of unauthorised entrants attempting to remove equipment from the building, including any residual copper or other metal, including wiring.[38] The Rules require the AER to have regard to the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers identified in the course of our engagement with electricity consumers.[39]

- we considered alternative options to removing the plant and equipment, and remediating the sites, but these alternatives were not considered to be prudent and efficient. These alternative options included:

  - shift load away from the zone substations, and then do nothing. This approach was not considered appropriate as it would not address the safety and security risks set out previously. As such, it would be unlikely to allow us to maintain the reliability, safety and/or security of the distribution system;

  - shift load away from the zone substations, but continue a maintenance program until redevelopment. This approach may allow us to manage some of the risks set out previously, but requires an ongoing stream of maintenance costs. It would also require additional security costs.

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[38] See, for example: Minutes from meeting with Melbourne City Council, *Management of decommissioned CitiPower zone substations within the Melbourne City Council area*, 9 April 2015.

[39] NER, cl. 6.5.6(e)(5A).

This approach, however, would not avoid the future need to remove the plant and equipment, and remediate the sites. Given their existing condition and size, neither the plant, equipment, nor existing structures would be reused in the eventual redevelopment of these zone substation sites.[40] Accordingly, relative to removing plant and remediating the sites immediately following decommission, this option was not considered to provide the best balance between prudency and efficiency; and

- the magnitude of the costs associated with the decommissioning of the five zone substations is material, and cannot be funded by other elements of our total operating expenditure allowance. For example:
  - due to prudent and holistic planning and network management, projects to decommission and remediate zone substation sites are extremely rare.[41] Specifically, the costs associated with such activities are not reflected in our base year; and
  - the AER's benchmarking analysis indicates that at a total operating expenditure level, we are in the top quartile of distributors.[42] As our costs are already efficient, absorbing future prudent and efficient cost increases would not reflect the efficient and prudent costs, or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives.[43]

1.7.3 Forecasting approach

The operating expenditure associated with decommissioning the five zone substations varies for each site, given the characteristics of the zone substation. For example, the external building in Prahran is freestanding, and would be demolished. In contrast, the zone substation at Spencer Street is housed within a larger building, and would only be remediated to the extent required to remove any corresponding hazards. Similarly, the volume of major plant varies for each site.

More generally, the forecast operating expenditure reflects the following:

- removal and disposal of major plant, including transformers and switchboards;
- identification and disposal of asbestos and asbestos containing equipment;
- identification and disposal of other types of indoor contaminants associated with batteries and oil containing equipment (including the pump out and remediation of sumps, pits and drains);
- disconnection from supply and removal of exposed wiring and hazards (following removal of major plant). Utilities would also be disconnected;
- remediation of outdoor yards at Prahran and Laurens Street (including testing, transport and disposal of contaminated soil);

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40 For clarity, these sites are not expected to be sold, as they may form part of future, efficient network plans if relevant augmentation triggers are met.

41 In 2007–2008 we decommissioned an existing zone substation at Southbank. The demolition and decommissioning costs, however, were capitalised as the substation was immediately rebuilt.

42 Refer to chapter 5 of our regulatory proposal.

43 NER, cl. 6.5.6(c).

- demolition of freestanding buildings at Prahran and Laurens Street; and
- a reduction in ongoing maintenance, consistent with the expectations set out in the AER's Expenditure Forecast Assessment Guideline—that where new capital expenditure activity does not increase output, operating expenditure would be expected to decrease.

The costs of decommissioning the five zone substations are non-recurrent, and the timing of these costs reflects the timing of the corresponding capital expenditure projects. The removal of plant and equipment, and the remediation of the site, however, results in an ongoing reduction in maintenance expenditure.

For clarity, although the five zone substations will be decommissioned, there is no intention to divest the land. These sites may form part of future, efficient network plans if relevant augmentation triggers are met. As such, it would not be prudent or efficient to sell the existing sites. The forecast operating expenditure for this step change, therefore, does not include any offsetting impact from the sale of the relevant sites.

Our forecasting approach is set out in the attached model, *CP Decommissioning Step Change*. A summary of these costs are shown in table 1.15.

Table 1.15 Decommissioning zone substations—annual step change ($m, 2015)

Step change	2016	2017	2018	2019	2020	Total
Decommissioning zone substations	1.6	-0.1	2.8	2.6	-0.3	6.7

Source: CitiPower.
Notes: Totals may not add due to rounding.