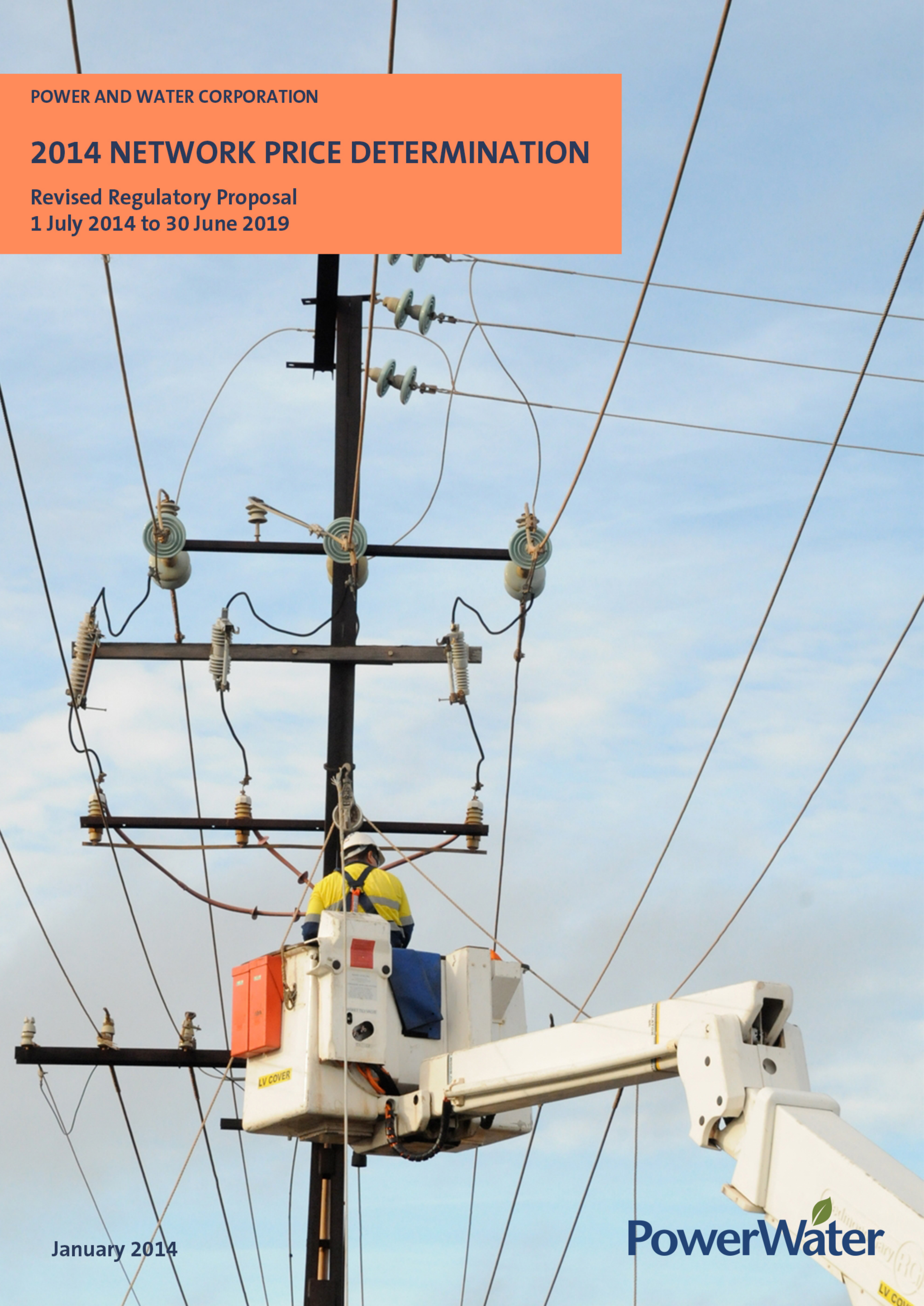
POWER AND WATER CORPORATION

2014 NETWORK PRICE DETERMINATION

Revised Regulatory Proposal
1 July 2014 to 30 June 2019



January 2014

PowerWater

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Foreword from the Managing Director

I am pleased to submit Power Networks' Revised Regulatory Proposal to the Utilities Commission (the Commission), for the fourth (2014-19) regulatory control period. This Proposal modifies some aspects of the Initial Regulatory Proposal submitted in September 2013, in accordance with the Commission's Draft Determination and with the provisions of the National Electricity Rules.

In its Draft Determination, the Commission in large measure recognised Power Networks' proposal for funding to permit the business to operate on a more commercial and sustainable basis. This recognition is welcomed, more so as it will establish Power Networks on a similar footing to the distribution network service providers in the National Electricity Market as it transitions to that regulatory regime.

Power Networks has reviewed the matters raised by the Commission in its Draft Determination, in particular where the Commission has made adjustments to its Initial Regulatory Proposal. Where applicable, Power Networks has implemented the adjustments required by the Draft Determination, or provided additional information and arguments to support its original proposal for the Commission's consideration. The Revised Regulatory Proposal also provides updated information, as foreshadowed in Power Networks' Initial Regulatory Proposal.

The Power Networks team and I look forward to working with the Commission in this final important phase of the regulatory process.

John Baskerville
Managing Director

1 Introduction

This document and its attachments comprise Power Networks' Revised Regulatory Proposal (Proposal) to the Utilities Commission (Commission) for the regulatory control period from 1 July 2014 to 30 June 2019. This Proposal is supported by:

- A memory stick containing copies of detailed documentation that substantiates the information presented in this main submission and its attachments;
- Other specific responses according to the requirements of the Regulatory Information Notice (RIN) issued on 9 April 2013, provided at Confidential Attachment 11; and
- An Overview Paper accompanying the Proposal, which summarises the Proposal for electricity customers and includes a description of key risks and benefits of the Proposal for electricity customers, provided at Attachment 1.

This Proposal updates the documents and associated information that were submitted to the Utilities Commission in September 2013. This Proposal does not restate elements of the Initial Regulatory Proposal that remain unchanged; rather, it is limited to the coverage of those matters that have changed.

Much of the detailed information that accompanies this Proposal, including that contained in the RIN templates, was submitted to the Commission in September 2013. This earlier information has been updated in this submission to take account of the Draft Determinations made by the Commission[1] and to update information where necessary. Where changes have been made to previously submitted material, the changes have been identified and the reasons for the change are explained.

Some attachments and supporting material forming part of this Proposal are considered commercial-in-confidence and have been indicated as confidential.

1.1 Executive summary

Power Networks is broadly supportive of the Commission's transition to the National Electricity Rules (the Rules) framework where appropriate and where consistent with the existing Northern Territory legislation. This has led to the current determination being carried out by the Commission within the Rules framework, including the adoption of the building blocks approach to determining Power Networks' revenue. As it is now apparent that the regulation of Power Networks will be transferring to the Australian Energy Regulator (AER), this process will accelerate the full range of regulatory guidelines, reporting requirements and compliance obligations that will be imposed on Power Networks.

[1] Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, December 2013.

Power Networks acknowledges much of the Commission's reasoning behind the Draft Determination. In most cases, Power Networks accepts that the constituent decisions made by the Commission are reasonable.

In some cases, Power Networks does not accept the rationale behind the decisions made by the Commission or believes further clarification is required. The principal areas where this is the case are as follows:

- The classification of services, in relation to the adoption of the Excess kVAr charge and inclusion of some additional descriptions;
- The demand and customer connections forecasts, where forecast growth rates have been arbitrarily reduced, with insufficient regard for the current and forecast economic conditions in the Northern Territory;
- The flow-on effects of these forecast changes, mainly to the capital expenditure forecast and some specific capital works projects;
- Some adjustments that the Commission has made to operating and maintenance expenditure programs and the associated expenditure forecast;
- The overall efficiency adjustment that the Commission has imposed on the operating cost forecast; and
- Some of the eligible pass through arrangements to apply during the 2014-19 regulatory control period.

This proposal sets out the reasons why Power Networks does not accept the rationale behind the Commission's decisions and, where necessary, provides additional supporting information.

This Revised Regulatory Proposal does not contain all of the background information provided in the Initial Regulatory Proposal. Rather, it updates and supplements information where necessary and retains sufficient earlier material to provide contextual reference.

This Proposal:

- Contains revised capital, operating and maintenance expenditure forecasts;
- Revises inadvertent formula errors in the NT Revenue Model (NTRM), as discussed with the Commission;
- Recalculates the proposed revenue and pricing paths and X factors;
- Results in a proposed P_0 of 50.59 per cent in 2014-15, an X factor of 15 per cent in 2015-16 and an X factor of 1 per cent for each subsequent regulatory year of the regulatory control period;
- Has customer cost impacts that are described in section 15 and in Power Networks' draft Pricing Proposal at Attachment 6;
- Is accompanied by the attachments and supporting information; and

- Is also accompanied by the required statutory declaration by Power and Water's Managing Director that the updated information provided as part of the Proposal is accurate and can be relied upon by the Commission, and certification from Power and Water's Board of Directors of the reasonableness of the updated assumptions.

1.2 Key Assumptions

As foreshadowed in Power Networks' Initial Regulatory Proposal, there were a number of assumptions that Power Networks reserved the right to update in this Revised Regulatory Proposal. Power Networks has now had the opportunity to assess the revised Electricity Standards of Service targets approved by the Commission under the 2012 NT Electricity Standards of Service Code (ESS Code). These standards affect the operating and capital expenditure forecasts, which have been updated to take account of the ESS Code requirements.

In addition, Power Networks has made a number of changes to the capital, operating and maintenance expenditure forecasts submitted with Power Networks' Initial Regulatory Proposal in instances where the forecast timing or cost of projects has been changed to address matters raised in the Draft Determination by the Commission.

The capital, operating and maintenance expenditure forecasts in this Proposal are based on the range of assumptions detailed in this Proposal. These assumptions are based on all available information at the time of preparing the Proposal.

In accordance with the RIN, Power and Water's Board of Directors have certified these updated assumptions as reasonable.

The global assumptions that apply to this Proposal are as follows:

- No changes to Power Networks existing structure and corporate and shared service arrangements. This is discussed further at section 1.4 below;
- No significant costs associated with changes to the current legislative and regulatory framework. This is discussed further at section 1.5 below;
- The revised Networks Technical Code and Network Planning Criteria[2];
- The Commission's approval of the proposed Networks Capital Contributions Policy (Attachment 5), Networks Services Classification (Attachment 3), Network Pricing Principles (Attachment 6) and Networks Cost Allocation Method (Attachment 7 and Confidential Attachment 14), amended as necessary to meet the requirements of the Commission's Draft Determination;
- CPI increases of 2.51 per cent per annum in the NTRM, as per the Commission's Draft Determination; and

[2] Power and Water Corporation, *Power Networks Network Technical Code and Network Planning Criteria: Version 3.1*, December 2013 (Attachment 2 of the Revised Regulatory Proposal).

- Network demand and consumption throughout the next regulatory control period will not materially deviate from the forecast detailed in section 6 of this Proposal.

More detailed assumptions are described in this Proposal and are included in the response to RIN Regulatory Template 7.3 provided at Confidential Attachment 11. These assumptions have generally been based on advice from reputable consultants who are well regarded by industry. All advice has taken into account relevant, up to date market and industry information.

1.3 Variation to information provided in the Initial Regulatory Proposal

The material variations that have been made to the information previously submitted to the Commission as part of the Initial Regulatory Proposal are set out in Table 1.1.

Table 1.1 – Variations to the Initial Regulatory Proposal

Information	Variation	Reason
Network service classifications	In the IRP, Power Networks proposed changes to the description of services to be provided and some additional services. The Utilities Commission modified many of these service descriptions in its Draft Determination and proposed some changes to the network service classifications.	In many instances Power Networks has accepted the Commission's proposed changes in the Draft Determination. However, there are some additional services where Power Networks does not accept the Commission's decision and there are some services where Power Networks believes a more complete description of the service is required.
Cost Allocation Method (CAM)	The CAM has been amended to state that the current Alternative Control Service cost allocation percentage includes both Alternative Control Services and Unregulated Services costs.	The Commission's decision to classify some of Power Networks proposed Alternative Control Services as Unregulated Services has necessitated a change to clarify the allocation of costs to each of the network services (ie. Standard Control Services (SCS), Alternative Control Services (ACS) and Unregulated Services) in the CAM.
Networks Capital Contributions Policy (NCCP)	The NCCP has been amended as follows: • 30 year connection life for small individual network users; • Clarification provided regarding the reuse of assets; and • Clarification provided regarding above standard services.	To align the NCCP with the recommendations in the Commission's Draft Determination.

Information	Variation	Reason
Forecast Expenditure	Forecast capital, operating and maintenance expenditure has been revised.	Power Networks reviewed each individual amendment that was recommended by the Commission in the Draft Determination and accepts some, but not all, of the adjustments to forecast expenditure.
Weighted Average Cost of Capital (WACC)	The WACC calculation in the NTRM has been updated.	Power and Water, after discussions with the Commission, discovered an inadvertent formula error in the effective tax rate for equity in the WACC calculation. The formula has been updated in the NTRM to align with the WACC calculation in the AER's Post-Tax Revenue Model.
Debt Raising Costs	The debt raising costs calculation in the NTRM has been updated.	The formula for debt raising costs has been updated in the NTRM to align with the calculation in the AER's Post-Tax Revenue Model.
Demand Forecast	Power Networks' demand forecast has been updated.	The forecasts have been updated for the latest available information.
2013-14 revenue estimate	The 2013-14 revenue estimate in the NTRM has been revised.	Power and Water has identified that the 2013-14 revenue estimate in NTRM was overstated, and the forecast has been revised downwards. Further information is provided in Power Networks' Pricing Proposal Model at Confidential Attachment 15.
Updates to RIN Templates	Confidential Attachment 11, which includes Power Networks' response to the Commission's RIN Templates, has been revised.	The RIN Templates have been updated for the latest available information.

1.4 Structural Separation of Power and Water

Since the submission of the Initial Regulatory Proposal, the Northern Territory Government has announced that Power and Water is to be split into the competitive and non-competitive businesses. The Generation and Electricity Retail business units will become separate stand-alone government-owned corporations (GOCs) from 1 July 2014, with the remaining 'monopoly' business units and residual functions remaining with the Power and Water GOC[3].

3 David Tollner (NT Treasurer), *Media release: New PWC Electricity Retail and Generation Corporations*, 13 December 2013.

At this time, the details of the structural separation are still being developed. In particular, the longer term arrangements regarding shared services and corporate overheads are currently unknown. The initial arrangements from 1 July 2014 are that corporate services will remain in the Power and Water GOC with Power Networks, so the current corporate overheads and shared services won't change significantly in the short term.

If the structural separation of Power and Water results in the imposition of significant costs on Power Networks, Power Networks would seek to recover this through cost pass through arrangements. In its Framework and Approach Decision Paper, the Commission advised that *"a structural separation event would fall within the ambit of other allowable events if it reflects a decision by Government as policy maker to improve the operation of the Territory electricity supply market. A decision to structurally separate PWC by Government as shareholder for commercial reasons would be unlikely to qualify as a pass-through event."*[4]

This is discussed further under pass through and contingent project arrangements in section 16.

1.5 Regulatory Reform of the NT electricity market

The Treasurer of the Northern Territory Government's submission in response to Power Networks' Initial Regulatory Proposal noted that Cabinet has approved a package of reforms for the Northern Territory electricity market, including application of relevant parts of the National Electricity Law (NEL) and National Electricity Rules (NER) for the economic regulation of distribution networks to be adopted by the Northern Territory from 1 July 2014[5].

As part of these reforms, responsibility for the economic regulation of Power Networks will be transferred from the Commission to the AER during the next regulatory control period, under transitional arrangements still to be developed.

Where known, Power Networks has forecast additional expenditure relating to transitioning to the NER in its RRP (for example, additional personnel required to comply with increased regulatory requirements). However, much of the detail in terms of the requirements, timing and nature of the transitional arrangements over the next regulatory control period are currently unknown. Where the regulatory reform imposes significant costs on Power Networks, Power Networks will apply for a Regulatory Change cost pass through event.

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4 Utilities Commission, *2014-2019 Network Price Determination – Framework and Approach Decision Paper*, November 2012, p. 82.

5 David Tollner (NT Treasurer), *Letter from the Treasurer re NPD and application of NER*, November 2013.

2 Business overview and context

An overview of Power Networks' business and the environment in which it operates was provided as part of the Initial Regulatory Proposal. This material is not restated in this Proposal.

2.1 Power Networks' role

In the Initial Regulatory Proposal, Power Networks also set out its role and the legislative framework under which it operates.

In the current regulatory control period and for this 2014 Network Price Determination, the Commission has progressively sought to implement the provisions of the Rules and the AER's approach to distribution regulation, where they are compatible with the legislation under which Power Networks operates. Nevertheless, this planned change will impose significant additional obligations on Power Networks and require the development of transitional Rules arrangements.

2.2 Organisational overview

Power Networks is a ring-fenced electricity distribution business within Power and Water, performing the role of the Network Operator, as defined in the *Electricity Networks (Third Party Access) Act*.

Since the submission of the Initial Regulatory Proposal, the Northern Territory Government has announced that Power and Water's business is to be split into competitive and non-competitive businesses. The Generation and Electricity Retail business units will become separate stand-alone government-owned corporations from 1 July 2014[6].

2.3 Power Networks' governance and strategic development

An overview of the following was provided in the Initial Regulatory Proposal:

- Governance procedures;
- Enhanced asset management practices;
- Strategic initiatives and programs;
- Strategic and operational risks; and
- Capability development and innovation.

This material is not restated in this Proposal.

[6] David Tollner (NT Treasurer), *Media release: New PWC Electricity Retail and Generation Corporations*, 13 December 2013.

2.4 Stakeholder expectations for the 2014-19 regulatory control period

In this Revised Regulatory Proposal, Power Networks remains committed to meeting the expectations of its stakeholders in a number of ways.

The proposed forecast expenditures have been kept to a minimum and their prudency and efficiency demonstrated. This will:

- Minimise the increase in prices to Power Networks' customers; and
- Ensure that non-network and demand management solutions are developed where they are economic; whilst
- Ensuring an appropriate commercial return on the electricity network business to our Northern Territory Government shareholder.

Power Networks proposes to maintain network security standards at around current levels and to make gradual improvements to reliability levels throughout the 2014-19 regulatory control period. Meeting our customers' expectations on reliability is an important priority, as customers need to receive a service that represents value for money.

Power Networks recognises there are some deficiencies in the current suite of network tariffs, which do not reflect the networks' cost structures and result in certain groups of customers paying more than their fair share of network costs. The Pricing Proposal that accompanies this Proposal explains how Power Networks proposes to develop cost reflective tariffs that are more equitable.

Where practicable, this regulatory Proposal has been developed in accordance with the Rules and the National Electricity Market (NEM) regulatory frameworks. During the course of the regulatory control period, further progress towards implementing NEM procedures will be made and will provide stakeholders with assurance that the regulatory bargain is being met in accordance with mainstream regulatory practices and standards.

3 Transitional issues

There are a range of transitional issues associated with the 2014-19 regulatory control period. The majority of these have arisen due to changes in transitioning to the NER and AER's regulatory framework.

3.1 Regulatory Information Notice requirements

The regulatory information requirements set out in the Commission's RIN are largely those which have been developed by the AER for its NEM distribution businesses. These requirements continue to evolve with development of the Rules framework and include the changes arising from the Distribution Planning and Expansion and the Economic Regulation of Network Service Providers Rule changes[7,8].

Annual regulatory reporting requirements

Power Networks anticipates that significantly increased reporting requirements will accompany the transition to the AER-based regulatory reporting framework. The annual reporting requirements for the NEM based distribution network service providers are much more onerous than Power Networks' current regulatory reporting obligations and will require annual updating of the RIN templates to accompany the regulatory accounts. This will require changes to systems and processes that will take place progressively.

Service Target Performance Incentive and Efficiency Benefits Sharing Schemes

Whilst the Commission has not fully implemented the AER's suite of regulatory incentives it has adopted some aspects, for example the implementation of Guaranteed Service Level arrangements that require additional resources. Power Networks is concerned that the Commission may proceed with other aspects of the AER's incentive schemes during the forthcoming regulatory control period, and notes that costs associated with these schemes has not been captured in the 2014 Networks Price Determination.

3.2 Regulatory modelling

A pre-tax framework has been used for regulatory modelling in the 2014 Networks Price Determination, using a modified version of the AER's Post Tax Revenue Model (PTRM). This has been termed the NT Revenue Model (NTRM). The PTRM was converted to a pre-tax framework by removing the tax calculation from the building block calculation and changing to a pre-tax Weighted Average Cost of Capital ($WACC_{Pre\ tax}$).

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7 AEMC, *Rule Determination – National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012*, 11 October 2012.

8 AEMC, *Final Position Paper – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012.

Regulatory Asset Base

The opening RAB for the 2014 Networks Price Determination as at 1 July 2014 has been developed from SKM's 2013 review of the Optimised Depreciated Replacement Cost (ODRC) of assets, rolled forward using the AER's Roll Forward Model (RFM).

Power Networks will maintain the RAB separate to the Financial Asset Register during the 2014-19 regulatory control period, due to differences in depreciation and in recognising capital expenditure as incurred, as opposed to capitalising Works in Progress (WIP) on project completion. This separate RAB will be maintained in a manner consistent with the RFM.

Taxation Asset Base

As required by the Commission, Power Networks has developed a project plan and timeframes to transition to a post-tax asset base for the regulated networks business[9].

Power Networks will develop and maintain a Network Tax Asset Base (TAB) separate to the Corporate taxation records, to enable the full implementation of the AER's post tax regulatory framework at the start of the 2019-15 regulatory control period. Power Networks proposes the following stages in this process:

- Development of initial Network TAB (as at 1 July 2015): 30 Sept 2015
- Review of network TAB, reconciliation with Corporate taxation and report to Commission: 30 Sept 2016
- Incorporation of TAB into revenue modelling: 30 Sept 2017

3.3 Pricing Proposal

Distributors in the NEM jurisdictions are required to lodge a detailed Pricing Proposal each year. The Pricing Proposals required under the NER are much more onerous than current Pricing Proposal requirements. Power Networks will need to develop its modelling and reporting systems to comply with additional reporting obligations.

Transition from a Price Cap to a Revenue Cap

The transition from a price cap to a revenue cap form of price control will result in changed modelling and reporting requirements. Whilst Power Networks believes the requirements of the revenue cap will be more straightforward, particularly in relation to the introduction of new tariffs and the transfer of customers between tariffs, a different form of price modelling will need to be developed, accommodating forecast tariff component growth to determine target revenues.

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9 Utilities Commission, *2014-2019 Network Price Determination – Framework and Approach Decision Paper*, November 2012, p. 57.

3.4 Network Management Plan

Power Networks produced its inaugural Network Management Plan in December 2012. Concurrently, progress towards the development of uniform distribution network reporting arrangements took place in the NEM, with the Distribution Network Planning and Expansion Framework Rule changes. The NEM requirements for the Distribution Annual Planning Report (DAPR) would impose significant additional obligations, with which Power Networks will not initially be able to comply.

Investment processes

The Commission has decided that the Regulatory Test is not appropriate for Territory circumstances[10]. Power Networks agrees with this decision. Power Networks accepts that some aspects of the RIT-D process, in particular consultation associated with developing non-network options, are adaptable to the Territory's circumstances. This will have an impact on the resources required to plan the network.

3.5 Network cost pass through

Power Networks submitted a cost pass through application to the Commission in February 2013[11]. This application related to additional costs incurred as a result of equipment failures at Casuarina Zone Substation and necessary changes to asset management practices.

The Commission's Final Determination on the Networks Cost Pass Through Application in May 2013 was that Power Networks should recover the approved cost pass through amount in two stages:

- $25 million in the 2013/14 regulatory year; and
- the remaining $29.92 million ($2012/13) will be carried over to the next regulatory control period commencing 1 July 2014.

The Commission determined that the remaining amount of $29.92 million is to be recovered over the 2014-19 regulatory control period as part of the 2014 Network Price Determination process[12].

The established provision in the NTRM has been used to incorporate this revenue carry over into the revenue and prices for the 2014-19 regulatory control period, as an equal amount (in real terms) in each regulatory year.

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10 Utilities Commission, *2014-2019 Network Price Determination – Framework and Approach Decision Paper*, November 2012, p. 64.

11 Power and Water, *Network Cost Pass Through Application relating to the Davies Review recommendations*, 5 February 2013.

12 Utilities Commission, *Cost Pass Through Application – Final Determination*, May 2013, p. 5.

Commission's Draft Determination

The Commission accepted Power Networks' proposal that the remaining cost pass through be recovered in equal parts (adjusted for the time value of money) in each year of the forthcoming regulatory control period. However, the Commission corrected an error in Power Networks' calculation which had resulted in a double counting of indexation for inflation[13].

Power Networks' revised proposal

Power Networks has adjusted the remaining cost pass through allowance in the NTRM to align with the Commission's calculation.

[13] Utilities Commission, *Cost Pass Through Application – Final Determination*, May 2013, p. 120.

4 Classification of services

In the Initial Regulatory Proposal, Power Networks proposed changes to the classification of services set out by the Commission in the Framework and Approach Decision paper. In many instances, Power Networks' response also provided more complete descriptions of the services provided.

4.1 Commission's Draft Determination

The Commission considered Power Networks' Initial Regulatory Proposal and other submissions and revised the classification of services in the Draft Determination[14]. The principal differences between the Commission's classification and Power Networks' proposal were as follows. The Commission:

- Has revised the descriptions of many services provided;
- Did not accept some of the new services provided by Power and Water; and
- Changed the classification of some services.

4.2 Power Networks' proposed classification of distribution services

Power Networks accepts that the Commission has not adopted all of the changes that Power Networks proposed in the Initial Regulatory Proposal. However, there remain some modifications that Power Networks believes were appropriate and a number of the service descriptions that should be clarified to improve transparency and certainty.

The principal change that Power Networks considers necessary to the Commission's Draft Determination is in the provision of network capacity in excess of Network Technical Code requirements. This was proposed as an Alternative Control Service by Power and Water and was rejected by the Commission.

4.2.1 Excess kVAr charge

The Initial Regulatory Proposal contained a description of the operation of the excess kVAr charge, which is not reiterated here.

The power factor of loads on the network has a significant impact on the network capacity that needs to be provided to maintain supply. A non-compliant customer with a not unusually low power factor of 0.7 presents a total power demand that is 29 per cent greater than that of a compliant customer with a power factor of 0.9. Each component of the network (Low Voltage, High Voltage etc.) must be designed to accommodate this additional demand. Moreover, the electrical losses in the network are proportionate to the square of the load and this non-compliant

[14] Utilities Commission, *2014-19 Network Price Determination – Draft Determination*, December 2013, Table 4.3, p. 34-38.

customer would contribute 65 per cent greater network losses. Power factor correction should thus be a matter deserving of enthusiastic regulatory support.

Power factor can be corrected at different levels of the network, using capacitors. The correction of small customers' loads is not usually economic. However, correction at large customers' premises is invariably the most effective solution, as it reduces the demand placed on the network at each upstream level. Power factor compensation at upstream locations is not as cost-effective as correction at the customers' premises.

The average costs of providing reactive power at different levels on the network can be readily estimated. The network must be designed to deliver kVA, and the increment in network capacity arising from a lower power factor at the customers' premises is directly proportional to the increase in kVA. An example calculation of the incremental cost for the Low Voltage network, based on Power Networks' long run marginal cost (LRMC) for the Low Voltage network of $253/kVA, is shown in Table 4.1.

Table 4.1 – Average cost per Excess kVAr

Power factor	0.90	0.85	0.80	0.70	0.60
kW	1.00	1.00	1.00	1.00	1.00
kVA	1.11	1.18	1.25	1.43	1.67
kVAr	0.48	0.62	0.75	1.02	1.33
Excess kVAr	0.00	0.14	0.27	0.54	0.85
LRMC	$253	$268	$285	$325	$379
Δ cost	-	$15	$32	$72	$126
$/Excess kVAr	**-**	**$110**	**$119**	**$135**	**$149**

The average cost of delivering excess kVAr to the Low Voltage level may thus be seen to be in the order of $110-$150/kVAr.

The proportion of Power Networks' large customers that have a power factor lower than the Network Technical Code requirement is significant. Although Power Networks already has kVA tariffs, the financial incentive for non-compliant customers to reduce their power factor is clearly insufficient and a small fraction of the cost these customers impose on the network. This has also been the experience of NEM distribution network service providers, where power factor improvements have only been obtained as a result of direct negotiation with the customers concerned or, in the case of SA Power Networks, through the use of their innovative Excess kVAr charge.

A network tariff design with a larger proportion of recovery through the kVA component would not materially alter this situation.

Illustrative example of the Excess kVAr charge

Customer A has a power factor of 0.95 and is compliant with the Network Technical Code. Customer B, on the other hand, with a power factor of 0.8, is non-compliant. Customer B is consuming approximately 19 per cent more network capacity than Customer A but does not pay 19 per cent higher network charges due to the tariff structure.

The reactive power demand of Customer B exceeds the Code limitation by 133 kVAr. This is the excess reactive power (termed "Excess kVAr") consumed by the customer.

Based on the two customers above, and Power and Water's current kVA demand tariff, the monthly bill for two customers with typical consumption volumes would be as shown in Table 4.2.

Table 4.2 - Illustrative example of Excess kVAr charge

	Customer A	Customer B
Consumption		
kW demand	500.0	500.0
Power factor	0.95	0.80
kVA demand	526.3	625.0
kVAr demand	164.3	375.0
kVAr limit	242.2	242.2
Excess kVAr	0	132.8
kWh per month	182,500	182,500
… peak	146,000	146,000
… off peak	36,500	36,500
kVA per month		
… peak	526.3	625.0
… off peak	421.1	500.0
Monthly bill		
SAC	$593	$593
Peak kWh	$4,499	$4,499
Off peak kWh	$1,310	$1,310
Peak kVA	$3,386	$3,868
Off peak kVA	$643	$751
	$10,431	$11,021
Excess kVAr		
$10.28/kVAr/mth		$1,366
	$10,431	$12,387
Avg $/kVA	**$19.82**	**$19.82**

In this hypothetical example, a charge of $10.28/kVAr/month is required with Power Networks' current tariff structure to achieve an equitable outcome (i.e. to apply the same average $/kVA rate to both customers). This has effectively increased Customer B's financial incentive to correct its power factor to the same level as Customer A.

Commission's Draft Determination

The specific points raised by the Commission in the Draft Determination, and Power Networks' responses, are as follows:[15]

"*4.52 The Commission considers that PWC Networks has not justified:*

- *why the tariff should be an alternative control service, given the tariff is related to the recovery of network augmentation costs which are recovered through standard control services*"

  The proposed Excess kVAr tariff is not designed to, and has not been structured to, recover the costs of augmenting the network. These costs are recovered through Standard Control Services. Rather, the tariff seeks to ***avoid*** imposing augmentation costs on all customers through the prices for Standard Control Services, by providing sufficient incentive for an individual non-compliant customer to comply with its obligations under the Network Technical Code.

  As this tariff component is not related to the recovery of network augmentation costs which are recovered through Standard Control Services, its classification as an Alternative Control Service is appropriate.

- *"whether the proposal to apply the tariff as a fee-based service is appropriate, given it is effectively a penalty for a non-compliant power factor and an incentive pricing signal rather than cost-recovery for the provision of a separate service"*

  The Excess kVAr tariff has been proven by SA Power Networks to be a highly effective incentive mechanism to ensure customers' compliance with the South Australian Electricity Distribution Code[16]. The intent of the tariff is certainly to provide an incentive pricing signal for customers to improve power factor, but only for those customers that are in breach of their Network Technical Code obligations.

  Power Networks does not accept that Excess kVAr is not a separate service. Standard Control Services include only those network services provided in accordance with the requirements of the Network Technical Code. Services that are above that standard or are non-standard are classified as Alternative Control Services. Reactive power, in excess of the Network Technical Code requirements, that is consumed by a customer is thus an Alternative Control Service.

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15 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, December 2013, p. 13.

16 Essential Services Commission of South Australia, *Electricity Distribution Code EDC/10*, February 2013.

> "*4.53 The NT Network Access Code requires that for a service to be determined to be an excluded service, the Commission must be satisfied that the costs associated with that service can be excluded from the cost base used for the purpose of calculating the revenue cap. The Commission is not satisfied that the specific costs of a low power factor of a specific customer can be identified.*"
>
> Power Networks' estimate of the average cost of excess kVAr at the Low Voltage level is presented in Table 4.1. The specific costs of power factor non-compliance, associated with a specific customer, cannot be identified unless they are the trigger for the augmentation of the network. This is also the case for the specific costs of customers' real power demand on the network and the very reason why averaged calculations, taking into account the LRMC of expansion of the network, are used as the basis for establishing cost reflective network tariffs. Power Networks does not accept that being unable to identify the specific costs associated with a specific customer's non-compliance is a valid reason to reject the proposed Excess kVAr tariff.
>
> Power Networks contends that the costs associated with the provision of excess reactive power as an excluded service can be readily identified on an averaged basis. Whilst these costs are material, they are of necessity an average across all customers that applies over an extended timeframe. The specific costs during the 2014-19 regulatory control period cannot readily be identified as a component of the networks' cost base, however they are unlikely to be material, and this should not preclude the Commission from determining Excess kVAr as an excluded service.
>
> Power Networks therefore considers that the Commission should determine the classification of the Excess kVAr tariff as an alternative control service, whilst determining that the costs to be excluded from the cost base used for Standard Control Services is immaterial.

With regard to the NTMEU's concerns regarding equity[17], Power Networks agrees that a network user must have a meter capable of measuring kVA to permit billing either of kVA, or excess kVAr. At this stage, customers with an annual consumption in excess of 750 MWh are equipped with such meters and it is proposed that the tariff should apply to them. Customers with this level of consumption would have a minimum demand of circa 250 kW. At this level of consumption, the impact of an individual customer on the network is usually material and the correction of the customer's power factor is both feasible and economic. Moreover, for these larger customers, energy bills are significant and their response to pricing signals relatively sophisticated.

[17] Northern Territory Major Energy Users, *Submission to Utilities Commission on PWC Networks Pricing Proposal: 2014 Regulatory Reset*, p. 17.

Metering capable of measuring reactive power will progressively be installed at smaller customers' premises. Power Networks expects that it may eventually extend the Excess kVAr charge to smaller customers, based on consultation and assessment of the customers' ability to understand the pricing signals and respond appropriately.

Power Networks Revised Proposal

This change and other changes that Power Networks believes are necessary to clarify the intent and transparency of the Commission's service descriptions for customers are set out in the Networks Services Classification at Attachment 3.

4.3 Amendments to the Cost Allocation Method

Power Networks did not report any Unregulated Services operating expenditure in the current regulatory control period and did not forecast any Unregulated Services operating expenditure over the forthcoming regulatory control period in its Initial Regulatory Proposal. Furthermore, no Unregulated Services were proposed in the Network Services Classification provided with the Initial Regulatory Proposal.

The Commission's decision to classify some of Power Networks' proposed Alternative Control Services as Unregulated Services has necessitated a change to clarify the allocation of costs to each of the network services (ie. Standard Control Services (SCS), Alternative Control Services (ACS) and Unregulated Services) in the Cost Allocation Method (CAM).

Power Networks has modified the CAM to state that the current ACS cost allocation percentage in the CAM includes both ACS and Unregulated Services costs. The forecast ACS operating expenditure in RIN Template 5.1 has also been clarified to state that it includes both ACS and Unregulated Services operating expenditure.

As these services were previously part of the ACS allocation of costs removed from SCS expenditure, the percentage removed from SCS expenditure does not need to change. Power Networks does not consider it necessary to modify the percentage into a separate ACS and Unregulated Services split, as it is not easily able to identify the percentage of costs associated with these Unregulated Services at this time, and therefore any split will be arbitrary.

5 Control mechanism for standard control services

The Commission proposed a revenue cap form of price control in the Framework and Approach paper. Power Networks initiated this change from the current Weighted Average Price Cap (WAPC) form of price control and supports this form of price control.

5.1 Commission's Draft Determination

The Commission has confirmed that a revenue cap form of price control will apply during the 2014-19 regulatory control period. Power Networks welcomes this decision.

In establishing customer side constraints, however, the Commission has deviated from the Rules provisions of side constraints that apply to tariff classes. The Commission has proposed that a side constraint of 2 per cent maximum price increase should apply to individual customers with consumption of >750 MWh p.a., rather than to tariff classes. Power Networks does not accept the Commission's decision on this matter for the reasons set out in section 5.3.

5.2 The revenue cap form of price control

The Commission has determined that Power Networks must submit network prices that comply with the following formula:

$$\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{i,j} \times q_t^{i,j} \leq R_{t-1} \times (1+CPI_t) \times (1 \pm passthrough_t) \pm \Delta R_t$$

where:

R_{t-1}	is the revenue in year *t-1*
CPI_t	is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year *t-2* to March in regulatory year *t-1*
Xt	is the allowed real change in revenue from year *t-1* to year *t* of the regulatory control period as determined by the Commission
$passthrough_t$	is any pass through amount in year *t* determined by the Commission, expressed as a percentage of the annual revenue
ΔRt	is the overs and unders adjustment to revenue in year *t*
n	is the number of network tariffs
m	is the number of tariff components
$p^t_{i,j}$	is the price of component *i* of tariff *j* in year *t*
$q^t_{i,j}$	is the forecast volume of component *i* of tariff *j* in year *t*
t	is the year for which prices are being set

t-1	is the year prior to the year *t* for which prices are being set
t-2	is two years prior to the year *t* for which prices are being set.

Power Networks accepts the Commission's proposal as an appropriate representation of the revenue cap mechanism. This formulaic expression is equivalent to that provided in the Initial Regulatory Proposal.

5.3 Side constraints

The Commission has determined that the price movement in network tariff classes must comply with the following formula:

$$\frac{\sum_{j=1}^{m} p_t^j \times q_{t-2}^j}{\sum_{j=1}^{m} p_{t-1}^j \times q_{t-2}^j} \leq (1+CPI_t)\times(1-X_t)\times(1 \pm passthrough_t)$$

CPI_t	is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year *t-2* to March in regulatory year *t-1*
Xt	is the allowed real change in revenue from year *t-1* to year *t* of the regulatory control period as determined by the Commission
Y_t	is the side constraint on revenue recovered from a tariff class [or customer] from year *t-1* to year *t* of the regulatory control period as determined by the Commission
$passthrough_t$	is any pass through amount in year *t* determined by the Commission, expressed as a percentage of the annual revenue
ΔRt	is the overs and unders adjustment to revenue in year *t*
n	is the number of network tariffs
m	is the number of tariff components
p^j_t	is the proposed price of component *i* of the tariff class in year *t*
p^j_{t-1}	is the proposed price of component *i* of the tariff class in year *t-1*
q^j_{t-2}	is the actual volume of component *i* of the tariff class in year *t-2*
t	is the year for which prices are being set
t-1	is the year prior to the year *t* for which prices are being set
t-2	is two years prior to the year *t* for which prices are being set.

Power Networks accepts the Commission's proposal as an appropriate representation of the side constraint mechanism, with the following exception. This formulaic expression is equivalent to that provided in the Initial Regulatory Proposal.

Side constraint on individual tariffs

The Commission has proposed that the side constraint of 2 per cent should apply to the prices of individual customers with annual consumption greater than 750 MWh. The Commission has stated its reasoning for imposing this restriction was that Power Networks had not provided information on price movements for these individual customers[18]. The Commission's proposal differs from the Rules, in that under clause 6.18.6 side constraints are only applied to the weighted average revenue movements of tariff classes.

Power Networks believes this proposal would unduly restrict overdue price restructuring for these customers, result in inefficient non-cost reflective prices being carried forward for decades. Inefficient pricing will impose greater costs on all customers, due to inappropriate customer demand response.

In the Initial Regulatory Proposal, Power Networks proposed a single percentage to apply to each pricing component of the existing network tariffs in 2014/15. The same percentage price change would thus apply to all customers and side constraints would not apply to customer price variations. In this Proposal, Power Networks again proposes a uniform price change for all tariff components in 2014/15.

The specific points raised by the Commission in the Draft Determination, and Power Networks' responses, are as follows:[19]

> "*5.33 PWC Networks has not provided details on the possible impact of this change in approach on individual customers.*"
>
> In the draft Pricing Proposal resubmitted at Attachment 6, Power Networks has included an example of the structural pricing changes it intends to progressively implement in the following years of the regulatory control period. This highlights the potential pricing outcome of price restructuring on individual large customers. This is similar to the approach adopted by other NEM distribution network service providers and accepted by the AER[20].

---

[18] Utilities Commission, *2014-19 Network Price Determination – Draft Determination*, December 2013, p. 43.

[19] Ibid, p. 42-43.

[20] See for, example: Ausgrid, *Ausgrid Network Pricing Proposal For the Financial Year Ending June 2013*, May 2012, p. 31, and SA Power Networks, *SA Power Networks Annual Pricing Proposal 2013-2014*, 24 May 2013, p.50.

"_5.33 … The Commission is concerned that, by applying the side constraint to the revenue for the tariff class, some customers may be subject to higher increases which are offset by correspondingly lower increases for other customers._"

This concern is not relevant under a revenue cap. Power Networks Maximum Allowable Revenue (MAR) is set for each year of the regulatory control period, and differences between the actual revenue recovered and the MAR are then reconciled in future years. Therefore there is no incentive for a network service provider under a revenue cap to subject some customers to higher increases than others. The revenue cap does, however, provide Power Networks with a clear financial incentive to propose tariff reforms that reduce demand related capital expenditure on the network.

"_5.34 In approving PWC Networks' tariffs for 2013-14, the side constraint was only required to be calculated for 195 individual customers. The Commission does not consider that this imposes an unduly onerous burden on PWC Networks._"

Power Networks accepts that necessarily an individual side constraint applied to 195 customers is not an unduly onerous requirement. This is not the primary reason for applying the side constraint to the tariff classes, which is to facilitate the introduction of tariff restructuring to improve the efficiency of pricing within a reasonable period of time.

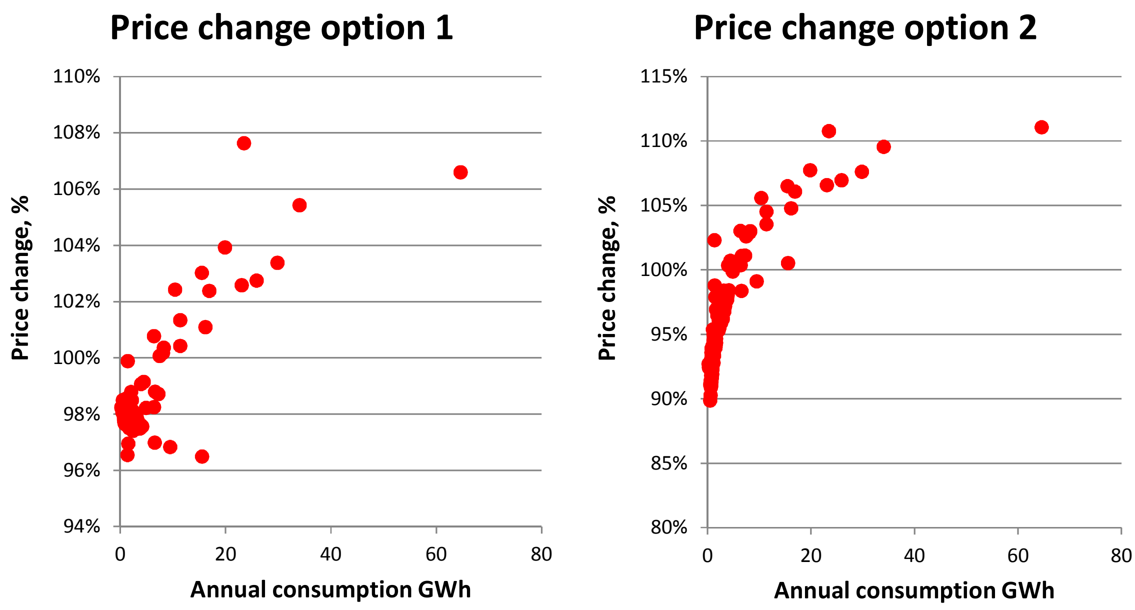
Power Networks proposes that the 2 per cent side constraint should apply only to the tariff classes of customers (ie. Domestic customers, Commercial Low Voltage customers and Commercial High Voltage customers), consistent with the Rules provisions that apply to all other distribution network service providers.

Examples of the type of pricing reform that Power Networks envisages, and of the impact of the proposed side constraint on individual customer price movements that the Commission proposes, are outlined below:

- Price change option 1: Increasing the two lowest (highest threshold) peak kVA blocks by 125 per cent of the proposed 2014/15 rates, whilst decreasing energy rates by 4 per cent to retain revenue neutrality; and
- Price change option 2: Equalising all peak blocks at $8.00/kVA whilst decreasing energy rates by 1 per cent to retain revenue neutrality.

The pricing impact of these hypothetical changes is illustrated by the scatter diagrams in Figure 5.1. The complex nature of these tariffs with multiple charging components results in a spread of pricing outcomes.

Figure 5.1 – Hypothetical pricing options



If the Commission's maximum movement in individual customer price of 2 per cent is applied, the following periods would be required to implement these price restructuring options:

Table 5.1 – Implementation period for pricing options

Pricing option	Number of years to implement
Increase the two lowest (highest threshold) peak kVA by 125% of 2014/15 demand rates and decrease energy rates by 4% (revenue neutrality)	4
Equalise all peak blocks at $8/kVA and decrease energy rates by 1% (revenue neutrality)	6

It is readily apparent that the Commission's proposal would result in extended periods for any meaningful pricing reform to take place. The requirement to limit the price change to accommodate a single customer has an impact on the maximum price change for the whole customer class. This will result in greater network costs for all customers, due to the perpetuation of inefficient pricing arrangements that do not target customers' demand response.

It should be clarified that Power Networks does not intend to introduce price restructuring at a pace that subjects customers to large price changes. The pace of restructuring will be limited and carried out in accordance with the consultation process in the Rules, as with the NEM distributors.

5.4 Compliance with control mechanisms

There are two aspects to compliance with the form of pricing control, namely:

- Compliance with the revenue cap; and
- Compliance with side constraints on the average revenue movement in tariff classes.

These aspects are discussed in the following sections.

5.4.1 Compliance with the revenue cap

Power Networks will submit prices in each regulatory year that comply with the form of price control set out in section 5.2. It will be necessary to adjust the term ΔRt to permit the revenue recovery through prices to track the allowable revenue. The mechanism to achieve this is the Overs and Unders account.

In the draft determination, the Commission has incorrectly stated the closing balance of the unders and overs account[21]. The appropriate formulation, as stated in the Initial Regulatory Proposal, is set out in Table 5.2.

Table 5.2 – Unders and Overs calculation

Element	**Year t-2** Actual	**Year t-1** Expected	**Year t** Forecast
Opening Balance	$Opening_{t-2}$	$Opening_{t-1}$ $= Closing_{t-2}$	$Opening_{t}$ $= Closing_{t-1}$
Interest on opening balance	$Opening_{t-2} \times W$	$Opening_{t-1} \times W$	$Opening_{t} \times W$
Under/over recovery for the year	ΔR_{t-2}	ΔR_{t-1}	ΔR_{t}
Interest on under/over recovery	$\Delta R_{t-2} \times V$	$\Delta R_{t-1} \times V$	$\Delta R_{t}- \times V$
Closing balance	$Closing_{t-2}$ $=Opening_{t-2} \times (1+V)$ $+ \Delta R_{t-2} \times (1+W)$	$Closing_{t-1}$ $=Opening_{t-1} \times (1+V)$ $+ \Delta R_{t-1} \times (1+W)$	$Closing_{t}$ $=Opening_{t} \times (1+V)$ $+ \Delta R_{t} \times (1+W)$

21 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination,* December 2013, Table B1, p. 134-135.

Where:

$Opening_t$	is the Unders and Overs opening balance in year t
ΔR_t	is the difference between allowable revenue and revenue recovered for the year t
W	is the nominal Weighted Average Cost of Capital (WACC) determined by the Utilities Commission for the regulatory control period
V	is the WACC applicable to a half-year (ie. $V=\sqrt{W+1}-1$)
$Closing_t$	is the Unders and Overs closing balance in year t

Power and Water will set network tariffs each year t to target a closing balance in the account as follows, in accordance with the Commission's decision:

- if $|\Delta R_t| \leq 2\%$ of MAR, the under/over recovery will be cleared within one regulatory year;
- if $2\% < |\Delta R_t| \leq 5\%$, the under/over recovery can be spread over two regulatory years; and
- if $|\Delta R_t| > 5\%$, Power and Water would submit a plan to the Commission detailing how it proposes to clear the balance of the Unders and Overs account.

Power and Water notes that the overs and unders provision will be first implemented in 2015/16.

5.4.2 Compliance with side constraints

Power Networks proposes to demonstrate compliance with the pricing side constraint for each tariff class, as required by the Rules. The form of this calculation is set out in section 5.3 and demonstrated in the draft Pricing Proposal (Attachment 6).

6 Demand forecasts

This section of the Proposal sets out Power Networks' proposed forecasts of demand, customer connections and energy consumption. The demand and customer connections forecasts underpin the capital and operating expenditure forecasts in sections 8, 9 and 10. The energy consumption forecast does not directly affect Power Networks' costs but is used to demonstrate indicative price trends.

6.1 Network global demand forecast

In the Initial Regulatory Proposal, Power Networks provided a forecast of global demand for each of the three separate systems (Darwin-Katherine, Alice Springs and Tennant Creek). The forecasts were based on the review of temperature-corrected historical actual demands and the history and the trends and expectations of a number of correlated economic variables.

The growth rates adopted by Power Networks for the 2014-19 regulatory control period have been updated since the Initial Regulatory Proposal and are summarised for the three separate systems, as follows:

- Darwin-Katherine 2.7%
- Alice Springs 0.0%; and
- Tennant Creek 0.0%.

6.1.1 Commission's Draft Determination

The Commission engaged consultant Parsons Brinckerhoff to review the demand forecasts. Based on advice by its consultant, the Commission noted that Power Networks' demand forecast process was not sufficiently transparent and well documented, with respect to the process that had been adopted and adjustments that that had been made[22].

The Commission acknowledged that Power Networks weather normalisation practice generally aligns with industry practice. However it repeated Parsons Brinckerhoff's concern that least squares regression analysis of historical data had been used as the basis to forecast trends[23].

The Commission concluded that Power Networks demand forecast is likely to be overstated and adopted Parsons Brinckerhoff's recommendation, as stated below:

> "*... we have examined a number of demand forecasts and note that approximately two or three years of deferral in forecast demand would be observed if historical temperature-adjusted growth trends were applied. In*

[22] Utilities Commission, *2014-2019 Network Price Determination – Draft Determination,* December 2013, p. 60.

[23] Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, p. 34.

our opinion, given the softening demand being experienced in all other Australian jurisdictions over recent years, and the corresponding reduction in demand forecasts across the industry, a deferral of forecast demand by three years is a reasonable expectation."[24]

6.1.2 Power Networks' global demand forecast

The matters the Commission raised as reasons for rejecting Power Networks' demand forecast are considered below.

Forecast process and documentation

Power Networks accepts the statements made by the Commission that the supporting documentation of the forecast process and the justification of specific adjustments could be improved. Power Networks is working towards improving these aspects of its forecasting processes.

Power Networks notes that Commission's 2011/12 Power System Review considered Power Networks' demand forecasting process and after conducting a reasonableness check adopted a forecast of 2.7% growth in the Darwin Katherine region[25]. This forecast growth has remained constant. The previous forecasts used least squares regression and the projection of linear trends, with no concerns noted. Power Networks understands that least squares regression of historical data is commonly used throughout the industry and does not accept that its use of this technique is inappropriate. The regression trends so formed are not used directly as the forecast projection but form one input to the selection of forecast growth.

Forecast outcomes

Power Networks does not accept that its global demand forecasts are biased or overestimated. They were constructed after consideration of weather normalised growth trends and the trends and expectations of relevant correlated economic indicators. That the forecast is not biased or overestimated is demonstrated by two points:

- The growth rates in the Southern regions are very much lower than the Darwin-Katherine regional forecast. The statements regarding the preferential selection of high growth data do not apply to these regions, despite the same process and techniques being applied. This is particularly the case in Tennant Creek where the forecast was adjusted (by expert opinion) below the historical regression trend; and
- Power Networks has demonstrated that the relationship between the Darwin-Katherine system demand and the Northern Territory's Gross State Product (GSP) has a very strong correlation coefficient, at 0.93. If the forecast demand growth had been aligned with the Northern Territory Government's

[24] Ibid, p. 36.

[25] Utilities Commission, *Power System Review 2011-12*, April 2013, p. 24–28.

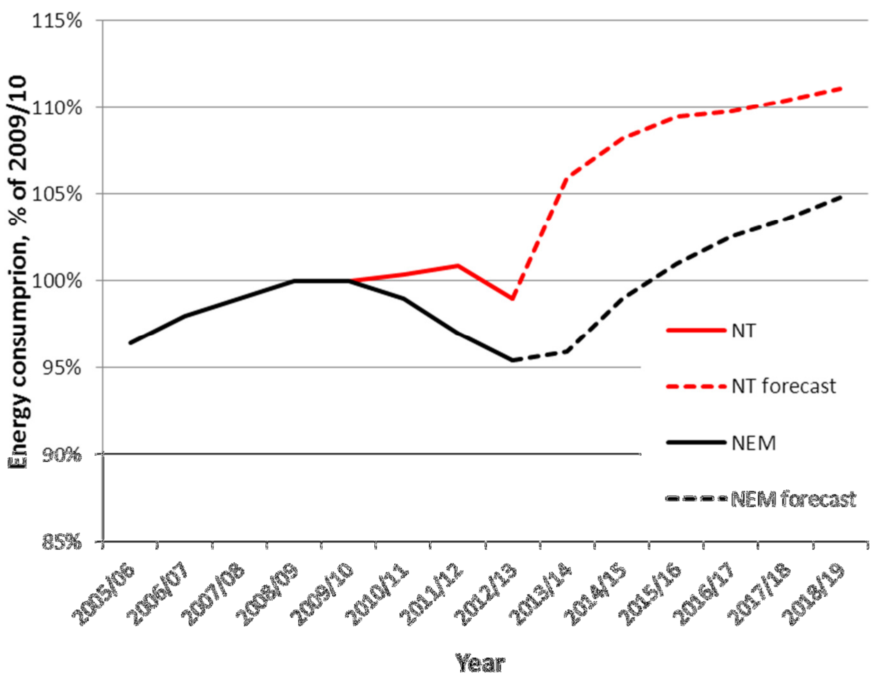
GSP, the growth in demand would be over 9 per cent[26]. Power Networks rejected this estimate as high, although it demonstrates the strength of independently determined growth drivers being experienced in the Northern Territory.

It is instructive to note the year-to-date maximum demand for wet season 2013/14 for the Darwin-Katherine system. The weather normalised demand of 298.1 MW on 1 November 2013 is slightly higher than the forecast of 298 MW (based on the 2.7% trend in demand growth) adopted by Power Networks. Power Networks considers that this outcome confirms the reasonableness of its global demand forecast.

Parsons Brinkerhoff recommendations

Parsons Brinckerhoff state that softening demand is being experienced in all other Australian jurisdictions over recent years, and there is a corresponding reduction in demand forecasts across the industry. This is indeed the case, as shown in Figure 6.1, which displays the energy consumption in the NEM and Australian Energy Market Operator's (AEMO) most recent energy forecasts[27].

Figure 6.1 – Annual energy consumption in the NEM and Northern Territory



Source: AEMO, 2013 NTNDP

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26 Northern Territory Government, *Territory Economic Review, Deloitte Access Economics - June Quarter 2013 (Updated),* July 2013, p. 11.

27 AEMO, *National Transmission Network Development Plan for the National Electricity Market (NTNDP) 2013*, 12 December 2013.

Superimposed on the AEMO forecast is Power Networks' energy consumption history and forecast for the 2014-19 regulatory control period. What is evident from this comparison is that the Northern Territory economy, being relatively strongly resource based, has not experienced to the same extent the downturn in economic activity and reductions in energy consumption as the NEM jurisdictions, in the period since the global financial crisis in 2007/08. It is not reasonable to infer that the conditions in other jurisdictions and their forecast softening in demand should directly apply to the Northern Territory.

Due consideration must be given to the specific growth drivers influencing the Northern Territory and the local regions. These growth drivers are demonstrated throughout Power Networks' spatial forecasts and comments, as well as within independent assessments such as the Territory Economic Review: [28]

> "*Deloitte's five year average forecast is for the Territory's economy to grow by an average of 4.7 per cent per annum between 2012-13 and 2016-17. This is the highest five year average annual growth rate of the jurisdictions and above the national rate of 2.9 per cent over the same period.*"

What is most concerning, however, is Parsons Brinckerhoff's recommendation that because, in its view, the global forecast has been over estimated, individual projects and programs should be deferred by three years in the mid to latter part of the forecast period. This displays a fundamental lack of understanding of the relationship between the global demand forecast and the local or spatial forecasts that drive the need for individual network augmentations.

The global forecast provides:

- An overview of the economic activity and pace of development in three regions of the Northern Territory; and is used to provide
- A "sanity check" to compare the top-down global forecast with the bottom-up spatial demand forecasts at the local level. The spatial demand forecasts are summed and the rate of demand growth of the sum checked with the global forecast for overall consistency.

There is no direct relationship between the global demand forecast and the individual elements of the spatial demand forecast, which are used to determine the need for, and timing of, individual projects. The deferment assessment made by Parsons Brinckerhoff is arbitrary and appears to be based solely on other Australian jurisdictions when there is clear evidence that the Northern Territory is experiencing independent growth drivers. Power Networks therefore does not accept either that:

- The global demand forecast has been overstated; or
- That it is reasonable for an overstated global demand forecast to be translated into an across-the-board three year deferral of capital projects.

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[28] Northern Territory Government, *Deloitte Access Economics – Territory Economic Review,* July 2013 (iteration 4).

6.2 Spatial demand forecasts

Power Networks develops spatial demand forecasts at the zone substation level and at the feeder level. The associated procedure was submitted as an attachment to the Initial Regulatory Proposal and the forecasts were used to determine the need for, and timing, of individual capital works projects. The growth rate arising from sum of the spatial demand forecasts was reconciled with the global forecast described in section 6.1.

6.2.1 Commission's Draft Determination

The Commission engaged consultant Parsons Brinckerhoff to review the spatial demand forecasts. As with the global demand forecast, the Commission noted that Power Networks' spatial demand process was not sufficiently transparent and well documented, with respect to the process that had been adopted and adjustments that that had been made.

The Commission did not accept Power Networks' spatial demand forecasts, on the basis of Parsons Brinckerhoff's opinion that the forecasts were biased and overstated. This resulted in the Commission proposing the deferral of specific projects, namely:

- PRD30309 Construct East Arm Zone Substation
- PRD30513 Construct Archer to Palmerstone 66kV line;
- PRA30750 Lovegrove Transformer 1&2 Upgrade
- PRD30402 Replace Berrimah Zone Substation; and
- PRD30115 Replace Casuarina Zone Substation 66kV Outdoor Switchyard.

6.2.2 Power Networks' spatial demand forecast

The Commission's 2011/12 Power System Review also considered Power Networks' spatial demand forecasting process and, after conducting a reasonableness check, adopted them[29]. Notwithstanding that no criticism of the forecasts was made in that Review, Power Networks accepts that improvements to the transparency and documentation of decisions can be made and intends to do this.

In relation to the specific projects that the Commission has proposed to defer, Power Networks has reviewed the forecast driving each of these projects and accepts some, but not all, of the associated capital expenditure adjustments. Each of the projects and Power Networks' response to the proposed adjustments is detailed in section 8.

[29] Utilities Commission, *Power System Review 2011-12*, April 2013, p. 46-47.

6.3 Customer connections forecast

In the Initial Regulatory Proposal, Power Networks proposed a customer connections forecast that was based on:

- Historical connections records; and
- Trends and current expectations in key economic variables.

The forecast number of customer connections influences forecast expenditures, mainly on network user initiated capital and metering, and flows through to upstream growth related augmentation. Power Networks' forecast of customer connections from the Initial Regulatory Proposal is shown in Table 6.1.

Table 6.1 – Customer connections forecast

Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
New Connections	1,810	1,900	1,960	2,020	2,075	2,130	2,190

6.3.1 Commission's Draft Determination

Based on advice by its consultant Parsons Brinkerhoff, the Commission noted that Power Networks' customer connections process was not accompanied by sufficient documentation of the process and adjustments that had been made.

The Commission did not accept that Power Networks' forecast of customer connections and stated that this forecast was biased and overestimated[30]. The Commission substituted Parson Brinckerhoff's forecast number of customer connections of 1,700 per annum, equivalent to the average over the 2009-14 regulatory control period, with no provision for growth in the number of customers connections during the 2014-19 period.

6.3.2 Power Networks' customer connections forecast

Power Networks accepts the statements made by the Commission that the supporting documentation of the forecast process and the justification of specific adjustments could be improved[31]. Power Networks is working towards improving these aspects of its forecasting processes.

Nevertheless, Power Networks does not accept that the Commission's adjustment to the forecast number of customer connections represents a reasonable expectation of forecast customer connections. This substituted forecast pays neither regard to historical growth in the number of customer connections, nor to the trends and expectations of closely related economic indicators.

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30 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination,* December 2013, p. 62.

31 Ibid, p. 61.

In support of Power Networks' forecast of customer connections, two more recent sources of information have become available since the submission of the Initial Regulatory Proposal:

- The actual number of new service connections made to the network during the five months from July 2013 to November 2013 is 783 connections. This figure extrapolated to 12 months is equivalent to 1,879 new service connections for the year 2013/14, effectively confirming Power Networks' estimate for this year; and
- The ABS re-published its Australian Demographic Statistics[32]. This document confirmed sustained high population growth in recent years (1.7 per cent to June 2012 and 1.8 per cent to June 2013).

Power Networks' forecast number of customer connections was based on a growth rate of 3.1 per cent declining to 2.7 per cent, selected after consideration of the following factors:

- Population historical trend (2005 to 2013) 2.0 per cent;
- Population forecast 1.5 per cent,
- Demand forecast (2012/13 – Darwin-Katherine) 2.7 per cent;
- GSP average historical growth 3.9 per cent;
- Connection numbers historical growth 3.8 per cent; and
- Dwellings - rolling 5 year average 2.7 per cent.

In contrast, the Commission's forecast of customer connections has a starting point 10 per cent lower than the 2013/14 year-to-date number of connections and zero growth throughout the 2014-19 regulatory control period.

Power Networks does not accept the Commission's substituted forecast and considers that the customer connections forecast submitted with the Initial Regulatory Proposal represents a more reasonable expectation of growth, particularly in the light of recent information. Power Networks has therefore retained the Initial Regulatory Proposal forecast of customer connections shown in Table 6.1.

6.4 Energy consumption forecast

Power Networks has not revised the energy consumption forecast submitted with the Initial Regulatory Proposal. This is shown in Table 6.2.

Table 6.2 – Energy consumption forecast (excluding unmetered consumption)

Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Energy MWh	1,622,947	1,707,179	1,743,346	1,764,240	1,768,815	1,779,910	1,791,075

32 Australian Bureau of Statistics, _3101.0 - Australian Demographic Statistics,_ December 2013.

7 Real cost escalation and CPI

Real cost escalation is an important input to the capital and operating cost forecasts, as those costs are not expected to escalate in line with CPI. This section sets out Power Networks' proposed real cost escalation rates and inflation assumptions.

Power Networks proposed real cost escalation figures in the Initial Regulatory Proposal, to apply to the capital and operating cost forecasts set out in sections 8 and 10. These were based on independent expert advice that Power Networks obtained from Deloitte Access Economics (DAE) and Sinclair Knight Merz (SKM). Power Networks had also nominated an inflation rate (CPI) for the purpose of modelling, in line with an estimate provided by DAE.

7.1 Commission's Draft Determination

In the Draft Determination, the Commission accepted Power Networks' real input cost escalators as reasonable[33].

The Commission chose an inflation rate averaging 2.51%, based on Reserve Bank forecasts and the approach used by the AER[34].

7.2 Labour cost escalation

Power Networks welcomes the Commission's decision to accept Power Networks' proposed real labour cost escalators. The escalators are shown in Table 7.1.

Table 7.1 – Real labour cost escalators

Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Internal labour	1.8%	1.7%	1.0%	0.6%	0.9%	1.0%
External labour	0.4%	1.0%	1.1%	0.9%	1.0%	1.1%

The labour cost escalators have been applied to the operating cost forecast set out in section 10.

7.3 Materials cost escalation

Power Networks also welcomes the Commission's decision to accept Power Networks' proposed real labour cost escalators.

33 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination,* December 2013, p. 95.

34 *Ibid*, p. 95.

The real materials cost escalators forecast by SKM are set out in Table 7.2 (capital expenditure) and Table 7.3 (operating and maintenance expenditure). These escalators include the effect of the Carbon Price Mechanism (CPM) and have been aggregated into the RIN categories.

Table 7.2 – Real materials cost escalators (capital expenditure)

Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
System Assets						
Transmission terminal station	1.3%	0.1%	-3.4%	0.4%	0.5%	-0.5%
Zone substations	1.4%	0.1%	-3.6%	0.4%	0.5%	-0.5%
Transmission lines	3.6%	0.9%	-4.9%	1.0%	1.3%	0.8%
Distribution mains	4.1%	1.1%	-3.1%	1.5%	1.6%	1.6%
Distribution substations	3.9%	0.9%	-3.5%	1.1%	1.1%	1.1%
Metering	1.3%	0.1%	-0.8%	0.5%	0.3%	0.2%
Secondary systems	1.3%	0.1%	-0.8%	0.5%	0.3%	0.2%
Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Non-System Assets						
IT and Communication	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Motor Vehicles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Plant & Equipment	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Table 7.3 – Real materials cost escalators (operating and maintenance expenditure)

Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Operating and maintenance expenditure	4.0%	0.6%	-3.2%	1.4%	1.1%	0.9%

Power and Water has applied these real material cost escalators to the capital and operating expenditure forecasts in sections 8 and 10 of this Proposal.

7.4 Consumer Price Index

The inflation rate is used in the modelling (the NTRM) to provide an indicative nominal revenue path. As actual revenues are adjusted for lagged out-turn inflation, the value of CPI has no influence on the actual revenues during the regulatory control period.

Power Networks accepts the Commission's proposed inflation rate. This is shown in Table 7.4.

Table 7.4 - Consumer Price Index forecast

Year	2014/15	2015/16	2016/17	2017/18	2018/19
Percentage movement	2.51%	2.51%	2.51%	2.51%	2.51%

8 Forecast capital expenditure

This section of the Proposal details Power Networks' capital expenditure forecast for the provision of Standard Control Services in the 2014-19 regulatory control period. Power Networks considers that this expenditure is required to meet the Code requirements and the capital expenditure objectives described within the Rules.

8.1 Commission's Draft Determination

The Initial Regulatory Proposal contained Power Networks' proposed capital expenditure forecast and supporting material.

The Commission engaged consultant Parsons Brinckerhoff to assess the prudency and efficiency of Power Networks' forecast capital expenditure. Parsons Brinckerhoff undertook a high level review of each capital expenditure category (augmentation, replacement, etc), including a number of specific reviews of individual capital projects, and recommended adjustments to the forecast.

The Commission adopted Parsons Brinckerhoff's recommended adjustments to the forecast capital expenditure and recommended a reduction of $57.8 million (real $2013/14 and escalated) over the 2014-19 regulatory control period[35], as demonstrated in Table 8.1.

Table 8.1 - Capital expenditure ($ million, real $2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
PWC Initial Regulatory Proposal	$84.74	$74.80	$57.44	$48.39	$57.58	$322.96
UC Draft Determination	$73.99	$50.88	$40.71	$45.00	$54.55	$265.13

8.2 Capital expenditure development process

An overview of Power Networks' capital expenditure development process was provided as part of the Initial Regulatory Proposal. This material is not restated in this Proposal.

In its Draft Determination, the Commission stated that they were satisfied that, in general, that the "*principles and practices set out in the Capital Investment and Delivery Framework and associated documents broadly accord with good industry practice and form a firm basis for PWC Networks to make efficient and prudent capital investment going forward*"[36].

35 Utilities Commission, *2014-19 Network Price Determination – Draft Determination*, December 2013, p. 80.

36 Ibid, p. 76.

Power Networks reviewed each individual amendment that was recommended by Parsons Brinckerhoff, and adopted by the Commission, and accepts some, but not all, of the associated capital expenditure adjustments. The following sections focus on those projects amended by the Commission, with reference to Parson Brinckerhoff's report[37], or amended by Power Networks and do not restate the summaries of those projects that were included in the Initial Regulatory proposal and accepted by the Commission.

8.3 Forecast network user initiated capital expenditure

Commission's Draft Determination

The Commission's Draft Determination recommends that network user initiated capital expenditure "*be reduced based on actual 2012-13 expenditure*"[38]. Power Networks notes, however, that this recommendation does not align with Parson Brinckerhoff's recommended total network user initiated capital expenditure, of which the Commission adopted. Total actual 2012-13 expenditure for the network user initiated capital expenditure category is significantly higher than the annual expenditure proposed by Power Networks for the 2014-19 regulatory control period.

Customer Augmentation and Network Extension Program (Sub8272)

Customers seek network extensions or upgrades and to the extent that the investment is supported by future increased tariff revenue from the customer, Power Networks fund and construct the associated assets.

Parsons Brinckerhoff recommended an adjustment to Sub8272 to take into account historical 2012/13 expenditure and their conclusions regarding Power Networks' customer connection forecast[39]. As outlined in section 6.3 of this Proposal, Power Networks does not accept that Parson Brinckerhoff's adjustment to the forecast number of customer connections represents a reasonable expectation of forecast customer connections. This substituted forecast pays neither regard to historical growth in the number of customer connections, nor to the trends and expectations of closely related economic indicators. The recommended forecast has zero growth in the number of customer connections during the 2014-19 regulatory control period and represents a 10 per cent reduction in year to date 2013/14 connections.

Power Networks has retained the Initial Regulatory Proposal forecast of customer connections as it considers that the customer connections forecast submitted with the Initial Regulatory Proposal represents a more reasonable expectation of growth,

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37 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013.

38 Utilities Commission, *2014-19 Network Price Determination – Draft Determination*, December 2013, p. 77.

39 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, Table 7.8, p. 47.

particularly in light of the recent information specified in section 6.3.2. Therefore, Power Networks has not adopted the recommended adjustment to the Customer Augmentation and Network Extension Program as it considers that that this expenditure is necessary to fund network extensions and augmentation over the forthcoming regulatory control period.

Customer Connection Program (Sub8275)

This program is for the provision of new electricity services to customers in both the overhead and underground reticulated areas.

Parsons Brinckerhoff note that, while this capital project was not subject to a detailed review, it is impacted by their conclusions in regards to Power Networks' customer connection forecast and has consequently recommended an adjustment to the capital expenditure associated with Sub8275 to account for what they conclude to be an overestimate in the forecast[40].

As explained above and in section 6.3.2, Power Networks does not accept Parsons Brinckerhoff's customer connections forecast and has therefore not adopted the recommended adjustment to the Customer Connection Program as it considers that that this expenditure is necessary to fund customer connections over the forthcoming regulatory control period.

8.4 Forecast augmentation capital expenditure

Commission's Draft Determination

The Commission's Draft Determination recommends that augmentation capital expenditure be reduced by the deferral of East Arm Zone Substation post-2019 and the deferral of the Archer to Palmerston 66kV line by two years, with the project completion deferred by three years due to revised expenditure timing[41]. Power Networks notes that the Commission has wholly adopted Parson Brinckerhoff's recommended adjustments to augmentation capital expenditure, which are more than those summarised by the Commission in its Draft Determination. In addition, Parson Brinckerhoff has only recommended the deferment of Stage 2 of PRD30309 Construct East Arm Zone Substation; Stage 1 of the project was deemed to be prudent and efficient and thus accepted.

Darwin: Construct East Arm Zone Substation (PRD30309)

The East Arm area has the potential, with short notice, to grow substantially and beyond Power Networks' current system capabilities with the addition of just one or two new major industrial customers. The proposed solution is to install an interim skid mounted or mobile substation in the near term (Stage 1) to ensure demand can be met, which will defer the requirement to build a new zone substation (Stage 2).

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40 Ibid, Table 7.9, p. 48.

41 Utilities Commission, *2014-19 Network Price Determination – Draft Determination*, December 2013, p. 77.

Parsons Brinckerhoff concluded that Power Networks' interim solution for East Arm is both prudent and efficient but recommended that Stage 2 of PRD30309 be deferred until after the 2014-19 regulatory control period. Power Networks accepts Parson Brinckerhoff's adjustments[42] and the deferment of Stage 2 of PRD30309, subject to Stage 2 being treated as a contingent project and the Northern Territory legislation being amended to allow for contingent projects with a threshold of $15 million. If the legislation is unable to be amended, then Power Networks requests that Stage 2 of this project be included in the 2014-19 forecast capital expenditure. This is discussed further in section 16.

Power Networks will continue to monitor load forecasts to ensure a safe, reliable and secure supply of electricity to the East Arm area. In addition, the potential for deferral of the works using demand management initiatives will be kept under review in order to ensure any investment is prudent and efficient.

Alice Springs: Lovegrove Transformer 1&2 Upgrade (PRA30750)

Parsons Brinckerhoff state that, while this capital project was not subject to a detailed review, it is impacted by their conclusions in regards to Power Networks' demand forecast and has consequently recommended the deferral of the capital expenditure, with the exception of expenditure for planning studies, until after the 2014-19 regulatory control period[43].

Power Networks note that Parsons Brinckerhoff did not complete a detailed review of PRA30750 and as such, the conclusions drawn by Parsons Brinckerhoff are not consistent with the justification of the project.

This project is primarily based on load increasing at Lovegrove Zone Substation due to expected altered generation conditions, in particular the retirement of generation assets at Ron Goodin Power Station, and not a result of a forecast regional demand increase. This retirement of assets, together with the relocation of base load machines at Owen Springs Power Station, will significantly alter the power flow in the Alice Springs electricity network and create constraints preventing the system from remaining secure during peak loads. Load transfer and transformer upgrades at Lovegrove Zone Substation are considered to be the lower cost option to address and relive these constraints, as well as providing long term growth solutions (as a secondary benefit).

Despite these issues, on review of the project, the most recent advice to Power Networks is that the retirement plans for the Ron Goodin Power Station are being reassessed by Power and Water Generation and the timing is not yet confirmed as being prior to 2018-19. Accordingly, Power Networks accept at this time that this project is not likely to be required in the 2014-19 regulatory control period and has

[42] Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, Table 7.14, p. 54.

[43] Ibid, Table 7.18, p. 58.

therefore removed the construction capital expenditure from the forecast, in line with Parson Brinckerhoff's recommended adjustment.

Darwin: Construct Archer to Palmerston 66kV Transmission Line (PRD30402)

Parsons Brinckerhoff has recommended a deferment of three years in the completion of PRD30402, based on their conclusions of Power Networks' demand forecasts[44]. As outlined in section 6, Power Networks does not accept Parson Brinckerhoff's opinion that Power Networks' demand forecasts are *"...likely to be overstated by about 3 years..."*[45]. This comment is based on an expectation that the Northern Territory growth drivers are directly related to those being experienced elsewhere in Australia, which is incorrect. Power Networks' decision to adjust the timing of this project between the staged submission and its Initial Regulatory Proposal does not reflect demand forecast uncertainty being beyond normal limitations, but rather it is an outcome of the staged approach of information, as agreed with the Commission.

Palmerston and surrounding areas at risk from the deferment of this project are experiencing the highest growth in the Northern Territory. The drivers of this growth are expected to continue as land and industry develops in this area. The current spatial demand forecast indicates that from 2013/14, system security will not be maintained under peak load conditions if a new line is not commissioned. In particular, the 'D' security requirement, as per the Supply Contingency Criteria in the Networks Planning Criteria, cannot be maintained, with approximately 90 MW at risk. With a reduction of new spot loads by 50 per cent, this constraint is deferred by one year to 2014/15 only.

Power Networks acknowledge that the Commission may accept short periods in breach of the system security requirements if this represents a low probability of occurrence (Load Duration Curve at risk x Load at Risk x Reliability), however Power Networks has completed an analysis that indicates the project is more efficient if completed in 2015/16, as planned by Power Networks. For this analysis, the proposed three year cash flow is maintained as per the Initial Regulatory Proposal as extending the project expenditure over a five year period, proposed by Parsons Brinckerhoff, will diminish the project benefits.

The 66 kV transmission lines that supply Palmerston (PA), McMinn (MM), Weddell (WD) and Archer (AR) zone substations are on a ring circuit that is connected to Hudson Creek (HC) Transmission Terminal Station. Humpty Doo (HD) and Mary River (MR) Zone Substations are also fed from this ring circuit via McMinn 66 kV bus. This transmission ring circuit has two sources, Weddell Power Station and HC Transmission Terminal Station.

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[44] Ibid, Table 7.17, p. 57.

[45] Ibid, p. 56.

Under normal operating conditions (no transmission outages), the existing lines can handle total peak demand of the aforesaid zone substations. However, using a 50 per cent reduced spot load forecast, from the year 2014/15, an outage on the HC-PA line will over load the WD-MM line (exceeding 80 MVA thermal rating of the line), which will cause load shedding at Palmerston Zone Substation. Similarly, from the same year, an outage on the WD-MM line will over load the HC-PA line, which will result in forced load shedding at McMinns Zone Substation. The proposed 66 kV transmission line from Archer Zone Substation to Palmerston Zone Substation will alleviate the above problem by maintaining adequate system security and, at the same time, reducing system losses through the change in system configuration.

In order to complete the comparative analysis for the efficient timing of the Archer to Palmerston 66kV transmission line, Power Networks followed the methodology explained below:

1. Half hourly load readings (SCADA) were obtained for Palmerston, McMinn, Humpty Doo and Mary River Zone Substations for the year 2012/13;
2. The Load Duration Curves (LDC) were normalised for the zone substations, based on the above data;
3. Standard weather maximum demands for the zone substations were obtained for the years 2012/13 to 2018/19, with an allocation of 100 per cent of new spot loads, as well as 50 per cent of new spot loads for Palmerston and McMinns Zone Substations;
4. Load flow simulations were conducted for the year 2013/14. These show that the maximum load that could be supplied through the WD-MM line when HC-PA line is out is 77 MVA. Similarly, the maximum load that could be supplied through HC-PA line when WD-MM line is out is 78 MVA;
5. Historical 66kV transmission outage data from Asset Management shows that lines similar to the HC-PA line and WD-MM line experience an average frequency of 1.711 outages per year, for an average outage duration of 3.58 hours;
6. A Value of Customer Reliability (VCR) figure of $48.17/kWh was used, based on AEMO 2012 data[46];
7. An average power factor of 0.96 was assumed for all zone substations;
8. The Energy not Served (ENS) due to line outages was calculated using a Frequency and Duration method[47]. This calculation was applied to updated LDCs (for yearly growth from 2013/14 to 2018/19) in half hour steps from peak demand to off peak demand to calculate energy not served using outage frequency and duration data. The VCR was then calculated directly;
9. Loss calculations for each year were also calculated using the power flow simulations with the proposed line and without the proposed line with a

[46] AEMO, _National Value of Customer Reliability (VCR) Final_, 19 January 2012.

[47] Billinton R, Allan RN, _Reliability Evaluation of Power Systems_, 1984.

short run marginal cost of $80/MWh applied to determine system loss savings; and

10. NPV analysis was undertaken to determine the cost/benefit of various project timings.

The NPV analysis demonstrates that the cost saving associated with deferral of the project to a commissioning date of 2019/20 is $1.25 million, while the benefit of commissioning the project in 2016/17 (from VCR and reduction of losses) is calculated as $2.20 million.

As such, Power Networks has not adopted the recommended deferment of PRD30402 Construct Archer to Palmerston 66kV Transmission Line and has maintained the capital expenditure timing as outlined in the Initial Regulatory Proposal.

8.5 Forecast replacement capital expenditure

Commission's Draft Determination

The Commission's Draft Determination recommends that replacement capital expenditure be reduced by removing some sub-programs, reducing Power Networks' estimates of unit rate costs, and by deferring the works at both Berrimah Zone Substation and Casuarina Zone Substation[48]. The Commission has also recommended that PRD30600 New Mitchell St Switching Station be treated as a contingent project, subject to legal clarification. Power Networks notes that the Commission has wholly adopted Parson Brinckerhoff's recommended adjustments to replacement capital expenditure, which are more than those summarised by the Commission in its Draft Determination. In addition, Power Networks notes that Table 7.39 (Recommended Replacement Capex) in Parson Brinckerhoff's report is incorrect and does not align with the recommended expenditure in preceding sections of their report.

Darwin: Replace Casuarina ZSS 66kV Outdoor Switchyard (PRD30115) and Darwin: Replace Berrimah Zone Substation (PRD30402)

Parsons Brinckerhoff has recommended a deferment of one year in the completion of PRD30115 and a deferment of two years in the completion of PRD30402, along with the removal of the 11kV circuit breakers from the scope of PRD30402. The deferment has been justified by Parsons Brinckerhoff on the grounds that it smooths out the resource requirements across the replacement projects.

Power Networks accepts the deferment of the Berrimah Zone Substation and Casuarina Zone Substation replacement projects and acknowledges it provides a more consistent year on year capital spend. The forecast capital expenditure has

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[48] Utilities Commission, *2014-19 Network Price Determination – Draft Determination*, December 2013, p. 77.

therefore been adjusted to align with the recommendations outlined in Parson Brinckerhoff's report[49].

The increased risk of asset failures posed by these deferments will be mitigated as far as practicable by existing processes that identify assets at risk due to poor condition.

Removal of excessive power transformer replacements

Parsons Brinckerhoff concluded[50], from the information provided by Power and Water, that the condition of the transformers at Berrimah and Casuarina Zone Substations was not sufficiently poor enough to justify the purchase and installation of new transformers at both zone substations. Parsons Brinckerhoff recommended an adjustment of $4.872 million ($2013/14, unescalated) to Power Networks' forecast replacement capital expenditure, equal to $1.218 million and $3.654 million ($2013/14, unescalated) in 2017-18 & 2018-19[51].

Based on the timing of the recommended adjustment, Power Networks assumes that this adjustment is for the removal of three new transformers from PRD30402 Replace Berrimah Zone Substation.

The magnitude of the adjustment indicates that the recommended adjustment includes the purchase cost for three 20/27MVA transformers, and an allowance for the costs associated with civil works and the installation of the three transformers including bunds, footings, services and sundry. This is summarised in Table 8.2.

Table 8.2 – Power Networks' interpretation of Parsons Brinckerhoff's adjustment for excess power transformers

Adjustment Breakdown	PB Adjustment ($2013/14, unescalated)
Total PB adjustment for removal of excess transformers	**$4.871M**
PWC estimate of purchase of three 20/27MVA transformers (based on recent purchase for the new Leanyer, Archer and Woolner Zone Substations)	$2.4M ($0.8M each)
Remainder of adjustment (assumed civil works and installation)	$2.471M

Power Networks does not accept that the purchase of three new transformers should be removed from the replacement capital expenditure forecast. In addition,

49 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, Table 7.23 and Table 7.28, p. 64 and 70.

50 Ibid, p. 61 – 64, and p. 67 – 70.

51 Ibid, Table 7.39, p. 89. Power Networks notes that the individual adjustments specified in Table 7.39 of Parsons Brinckerhoff's report are incorrect, as confirmed by the Commission. Power Networks has based its analysis on a revised Table 7.39.

the magnitude of the adjustment also appears to be too high based on the actual cost of recent transformer purchases, and the requirement to construct new footings, bunds, electrical services and for commissioning; which is required for environmental and safety reasons, regardless of whether new transformer are purchased or not.

Recent purchases by Power Networks of standard 20/27MVA transformers average at $0.8 million per transformer. The cost of associated bund works is estimated at $0.2 million per transformer, which would still be required if Power Networks used the existing transformers as the current bunding (including oil/water separation) does not meet Australian Standards.

If the three transformers were to be removed from the scope, a more reasonable adjustment of $2.4 million only should have been applied. Given the known condition of the existing transformers and associated high maintenance costs, Power Networks would dispose of these transformers.

The reasons for Power Networks' decision not to accept Parsons Brinckerhoff's adjustment are outlined in more detail below:

- PRD30402 has been planned as a complete replacement and the existing zone substation is required to remain in service during the 18 to 24 month construction and commissioning period. As such, in-situ replacement (requiring prolonged outages) is not an acceptable system risk.
- The existing transformer bunds at Berrimah Zone Substation do not meet current Australian standards for oil spillage and containment. Replacement or upgrade in their current location may not be possible and is likely to be significantly more expensive than the cost of new 'greenfield' bunds. The utilisation of existing bunds is not deemed to be acceptable by Power Networks due to non-compliance with Australian standards and the known increased risk of failure associated with transformers with aged and degraded insulation.
- It would be inefficient not to replace these transformers during the zone substation replacement. Replacing the transformers during the zone substation replacement provides efficiency in terms of mobilisation of design, construction, and commissioning resources. It also provides opportunity to optimise design with the use of known parameters (i.e. reduction of risk).
- The standardisation of Power and Water's zone substation transformer fleet provides opportunities to reduce the number of system spares and associated storage and maintenance costs.

Darwin: New Mitchell Street Switching Station (PRD30600)

The Commission has excluded the forecast expenditure for PRD30600 and states that *"the Commission will give consideration to including this as a contingent project if there is legal clarification of the scope for such arrangements in the NT Network*

Access Code'[52]. Power Networks accepts the removal of this project from the 2014-19 forecast capital expenditure, subject to the Northern Territory legislation being amended to allow for contingent projects with a threshold of $15 million. If the legislation is unable to be amended, then Power Networks requests that this project be included in the 2014-19 forecast capital expenditure. This is discussed further in section 16.

Asset Replacement and Upgrade Program (Sub8274)

The Asset Replacement and Upgrade Program targets specific asset classes or types that require replacement or augmentation, or network safety improvements that require capital investment.

Parsons Brinckerhoff recommended, and the Commission adopted, the following adjustments to Sub8274[53]:

- The removal of the following sub-programs: Substation Gate Upgrade for Emergency Egress, and Miscellaneous Zone Substation Equipment Replacements;
- The reallocation of the RLS testing portion of the Distribution Pole Extension sub-program from capital expenditure to operating expenditure; and
- Adjustments to the timing of the capital expenditure requirements. to smooth resource

Power Networks accepts the removal of the Substation Gate Upgrade for Emergency Egress, and Miscellaneous Zone Substation Equipment Replacements sub-programs, and the reallocation of the RLS testing portion of the Distribution Pole Extension sub-program from capital expenditure to operating expenditure. The capital expenditure forecast has been updated to take into account these adjustments.

However, Power Networks does not accept the arbitrary adjustments that have been made to the timing of the expenditure. Without further information provided by the Commission or Parsons Brinckerhoff, Power Networks is unable to understand the calculation behind this adjustment, nor which particular projects the annual adjustments apply to. The timing of Power Networks' proposed projects are based on available asset data and a philosophy of removing assets that present a high level of risk to Power Networks' personnel and the public in a reasonable timeframe. Where asset data is not available, the industry trends and knowledge have guided the timing of these works.

Furthermore, over the last five years, Power Networks has substantially improved its capability in delivering a high level of capital project delivery. As outlined in its Initial

52 Utilities Commission, *2014-19 Network Price Determination – Draft Determination*, December 2013, p. 77.

53 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, Table 7.35, p. 82.

Regulatory Proposal, Power Networks has introduced a number of strategies to ensure the organisation is capable of effective delivery of the capital program requirements. During the current regulatory control period, Power Networks has managed significantly higher levels of annual capital expenditure than those forecast during the 2014-19 regulatory control period and it is not expected that this further smoothing of capital expenditure is required.

Meters/Metering Program (Sub8276)

The Meters/Metering Program is required for the following metering programs over the forthcoming regulatory control period: new meter installations, meter replacements, prepayment meter replacements and a smart meter pilot.

Parsons Brinckerhoff recommended, and the Commission adopted, the following adjustments to Sub8276[54]:

- Reduction in the number of replacement meters;
- The removal of expenditure associated with asbestos monitoring for meter boards installed after 1980; and
- Reduction in the number of new meter installations.

Power Networks accepts the reduction in the number of replacement meters and the removal of expenditure associated with asbestos monitoring for meter boards installed after 1980. The capital expenditure forecast has been updated to take into account these adjustments.

However, Power Networks does not accept the reduction in the number of new meter installations to align with Parson Brinckerhoff's revised customer connection forecast. As discussed earlier in Section 8 and in section 6.3.2, Power Networks does not accept Parsons Brinckerhoff's customer connections forecast as it pays neither regard to historical growth in the number of customer connections, nor to the trends and expectations of closely related economic indicators. The recommended forecast has zero growth in the number of customer connections during the 2014-19 regulatory control period and represents a 10 per cent reduction in year to date 2013/14 connections.

As such, Power Networks has not adopted the recommended reduction in the number of new meter installations as it considers that that this expenditure is necessary to fund new meter installations over the forthcoming regulatory control period.

Reduction in replacement unit rates

Parsons Brinckerhoff reviewed superceded expenditure for Sub8274 Asset Replacement and Upgrade Program, included in Power Networks' staged submission, and concluded that the unit rates used to develop the expenditure forecast was over

[54] Ibid, Table 7.38, p. 88.

estimated by an average 8 per cent[55]. Parsons Brinckerhoff then recommended all replacement projects, with the exception of PRD30117 Rebuild McMinns 66/22kV Zone Substation and the metering replacements included in Sub8276 Meters/Metering Program, be reduced by 8 per cent to address this assumed overestimate in unit costs.

Power Networks does not accept this reduction in replacement capital expenditure for a number of reasons:

- Parsons Brinckerhoff based this unit rate comparison on costs included in Power Networks' staged submission of Sub8274 Asset Replacement and Upgrade Program and not those costs that were revised downwards for the capital expenditure included in Power Networks' Initial Regulatory Proposal, thus overestimating the differential;
- To conclude that Power Networks' unit rates are overestimated disregards the fact that unit rates are higher in the Northern Territory when compared to interstate. This evidenced in SKM's 2013 Modern Equivalent Asset Unit Rate Comparison report[56], where SKM demonstrated that there was an increased cost of undertaking capital works in the Northern Territory. SKM determined that unit rates in the Northern Territory are, on average 5.9 per cent higher when compared to comparable unit rates interstate; and
- The replacement component of the Asset Replacement and Upgrade Program makes up approximately 10 per cent of Power Networks' proposed forecast replacement capital expenditure. To then reduce the majority of Power Networks' forecast replacement capital expenditure, based on the conclusions of one project is flawed. In addition, a considerable portion of Power Networks' replacement capital expenditure is comprised of large zone substation related replacements, which are generally based on costs from previous contracts and period contracts, and are not of the type included in Sub8274.

For the reasons outlined above, Power Networks has not adopted the recommended reduction in replacement unit rates as it considers that that this expenditure is necessary to fund replacement projects over the 2014-19 regulatory control period.

Deferral and smoothing of zone substation works

Power Networks does not accept the arbitrary smoothing adjustments that have been made by Parsons Brinkerhoff, and adopted by the Commission, to the capital

55 Ibid, Table 7.33, p. 80.

56 SKM, *Modern Equivalent Asset Unit Rate Comparison*, 18 June 2013 (Attachment 22 of Power Networks' Initial Regulatory Proposal).

expenditure on zone substations under the replacement capital expenditure category[57].

Without further information provided by the Commission or Parsons Brinckerhoff, Power Networks is unable to understand the calculation behind this adjustment, nor which particular projects the annual adjustments apply to. The timing of Power Networks' proposed projects are based on available asset data and a philosophy of removing assets that present a high level of risk to Power Networks' personnel and the public in a reasonable timeframe. Where asset data is not available, the industry trends and knowledge have guided the timing of these works.

Furthermore, over the last five years, Power Networks has substantially improved its capability in delivering a high level of capital project delivery. As outlined in its Initial Regulatory Proposal, Power Networks has introduced a number of strategies to ensure the organisation is capable of effective delivery of the capital program requirements. During the current regulatory control period, Power Networks has managed significantly higher levels of annual capital expenditure than those forecast during the 2014-19 regulatory control period and it is not expected that this further smoothing of capital expenditure is required.

8.6 Forecast reliability and quality capital expenditure

Commission's Draft Determination

The Commission's has accepted Power Networks' forecast reliability and quality capital expenditure but has recommended that the largest reliability project be undertaken earlier than proposed by Power Networks[58].

Darwin: Rebuild the CIPS to Hudson Creek 132kV Transmission Line – Elizabeth River Crossing (PRD30003)

Power Networks notes that this project is for the construction of a section of new 132kV double circuit spanning the Elizabeth River and not the rebuild of the entire Channel Island Power Station to Hudson Creek 132kV transmission line[59].

The Commission has accepted this project but has recommended that this project should be undertaken one year earlier than that proposed by Power Networks[60]. Parsons Brinckerhoff state that *"the proposed capital expenditure associated with*

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57 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, Table 7.39, p. 89. Power Networks notes that the individual adjustments specified in Table 7.39 of Parsons Brinckerhoff's report are incorrect, as confirmed by the Commission. Power Networks has based its analysis on a revised Table 7.39.

58 Utilities Commission, *2014-19 Network Price Determination – Draft Determination*, December 2013, p. 78.

59 Ibid, p. 78.

60 Ibid, p. 78.

the CIPS to Hudson Creek 132kV Transmission Line – Elizabeth River Crossing is prudent when commissioned as soon as practically possible, to ensure that optimal risk mitigation is achieved. Moreover, we are of the opinion that the selected option is the efficient solution to the identified constraint"[61].

Power Networks intends to commission the Elizabeth River Crossing rebuild as soon as practically possible, as per Parsons Brinckerhoff's recommendation, but is unable to bring the project forward one year, with construction commencing in 2014/15, as recommended by the Commission in the Draft Determination.

Further project development work is required to firm up the crossing route and gain environmental and other government approvals. This work needs to be completed before Power Networks starts on a procurement strategy, after which detailed design would commence followed by construction that is constricted to the dry season only.

As such, Power Networks has not adopted the recommended timing change to PRD30003 Rebuild the CIPS to Hudson Creek 132kV Transmission Line – Elizabeth River Crossing and has maintained the capital expenditure timing as outlined in the Initial Regulatory Proposal.

Feeder Upgrade Program (Sub8262)

Each year Power Networks develops feeder performance reports for all poorly performing feeders. These reports include analysis of five years of historical outage data and interruption causes. The results of the analysis are targeted feeder upgrades planned for the upcoming financial year.

In its Initial Regulatory Proposal, Power Networks noted that the forecast expenditure would be updated in its Revised Regulatory Proposal based on the recently approved electricity service standard targets under the 2012 NT Electricity Standards of Service (ESS) Code. These targets were approved on 12 July 2013, and Power Networks did not have sufficient time to review the forecast to determine the impact on the Feeder Upgrade capital expenditure program.

For the Revised Regulatory Proposal, Power Networks has assessed the impact on the forecast expenditure of the revised Electricity Standards of Service targets approved by the Commission under the 2012 NT Electricity Standards of Service Code, and has revised the forecast capital expenditure accordingly.

The revised Sub8262 Feeder Upgrade Program justified against the Capital Expenditure Objectives and Criteria is included at Confidential Attachment 12.

61 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, p. 95.

8.7 Capital expenditure in the 2014-19 regulatory control period

The forecast of capital expenditure is included at Attachment 4, and is also summarised in Table 8.3.

Table 8.3 - Capital expenditure ($ million, real $2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Capital expenditure	$79.1	$66.8	$45.7	$42.9	$57.9	$292.46

This capital expenditure has been used in the NTRM to determine Power Networks' revenue requirement and prices described in section 15.

9 Capital contributions

Power Networks submitted a revised Capital Contributions Policy as Attachment 5 to the Initial Regulatory Proposal. This was reviewed by the Commission and their consultant Deloitte as part of the Commission's Draft Determination.

Power Networks' capital contributions forecast for the 2014-19 regulatory control period was developed based on the revised Capital Contributions Policy.

9.1 Commission's Draft Determination

The Commission accepted that Power Networks' Capital Contributions Policy complied with the requirements of the NT Access Code and the *Electricity Reform Act,* subject to Power Networks resolving two issues:[62]

- Power Networks had proposed a 15 year period for the calculation of capital contributions for small network connections. The Commission requires this to be amended to a 30 year life to apply to small network connections, for consistency with the NT Access Code; and
- The Commission is seeking confirmation that customers should not be charged for the full cost of the connection assets if other customers can benefit from the connection at that time or in the future.

The Commission accepted Power Networks' capital contributions forecast for the 2014-19 regulatory control period. The capital contributions forecast is not impacted by the Commission's proposed changes to the revised Capital Contributions Policy.

9.2 Proposed 2014 Network Capital Contributions Policy

In relation to the two issues raised by the Commission, Power Networks has made the following changes to the Capital Contributions Policy.

9.2.1 Connection analysis period

Power Networks accepts the Commission's amendment of a 30 year period for the calculation of capital contributions for small individual network users and has amended the Capital Contributions Policy accordingly.

9.2.2 Re-use of assets

The re-use of assets assumes that the customer is able to nominate a termination date so Power and Water is able to take the re-use of the asset into consideration when calculating the capital contribution. It also assumes that Power and Water is able to re-use, and has a use for, the asset after the customer no longer requires it. Given this uncertainty, Power and Water has not proposed to take into account the potential re-use of assets in the capital contributions calculation.

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62 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination,* p. 126.

Instead, Power and Water is proposing to take this into account at the time that a customer ceases to take supply, and has amended the Capital Contributions Policy accordingly.

In the case of a supply to a customer that has a known limited life, the contribution analysis period is tailored to the expected life of the connection and the value of recoverable assets (less recovery and restitution costs) is taken account of directly in the capital contributions calculation. However, the life of the connection is not usually known and this provision would apply infrequently, to a project such as a mine supply.

The assets that form a new connection comprise:

- Network extensions, which are funded by a pioneer customer but may be subject to the capital contributions sharing arrangements if a customer subsequently connects to the asset; and
- Dedicated connection equipment, which is also funded by the customer but is not used or useable by other customers (for example, a line across private property or an on-premises distribution substation).

It is usually not possible, at the time the customer requests a connection, to predict when the customer will cease to take supply. It is therefore inappropriate to make any adjustment to the capital contribution for this eventuality. Indeed, in determining that the analysis period for the connection should be extended to 30 years, the Commission has effectively assumed that all customers will take supply continuously for at least this period.

It should also be noted that where a connection asset is removed, the cost of removal of a line would be well in excess of the recoverable value of any useable materials. Only in the case of the removal of an on-site distribution substation, is it possible that the transformer and equipment could be re-used.

Where a customer does cease to take supply:

- Where relevant, the sharing arrangements set out in the Capital Contributions Policy apply for a period of 5 years. Where another customer had connected to the extension, a proportionate refund would have been made to the pioneer customer. If no other customer had connected to the line, it is likely that Power and Water would remove the line, in order to reduce its statutory obligations to maintain an unused asset.
- In some instances, where dedicated connection equipment is removed from an unused supply (such as distribution transformers), it may be possible to re-use assets.

Power Networks accepts that, in this latter circumstance, the customer is entitled to a refund in respect of assets that are re-used. The Capital Contributions Policy has been amended to require Power and Water to reimburse the customer for the depreciated value of the recovered assets, less the cost of their recovery and restoration costs, to the extent the customer has contributed towards the assets.

The Revised Capital Contributions Policy with proposed clarifications is at Attachment 5.

9.2.3 Above Standard Services

The Commission's consultants, Deloitte, also advised that section 11 of the Capital Contribution Policy implies that customers who request above standard services would pay for the full cost of the works, and that this aspect should be clarified when Power and Water submits a revised policy. Power and Water accepts that this should be clarified, and has amended the Capital Contributions Policy to state that a customer will only be charged the incremental cost of the work above the standard service[63].

This section also refers to *"the charging methodology approved by the Commission for Alternative Control Services - Quoted Services"*. This should not have been included, as the Commission outlined in its Framework and Approach Final Decision Paper that it will not apply any price control mechanism for services other than standard control services[64], and that it does not have a role in approving either the charges for alternative control services or the escalation arrangements to be applied to these by Power and Water in the fourth regulatory control period[65]. Power and Water has subsequently removed this part from the Capital Contributions Policy.

9.3 Forecast capital contributions

The forecast capital contributions for the 2014-19 regulatory control period are shown in Table 9.1.

Table 9.1 - Capital contributions forecast ($million, real $2013/14)

Capital Contributions	2014/15	2015/16	2016/17	2017/18	2018/19
Cash contributions	$2.61	$2.65	$2.68	$2.72	$2.75
Contributed assets	$9.23	$9.48	$9.74	$10.00	$10.27
Total capital contributions	$11.85	$12.13	$12.42	$12.72	$13.03

63 Deloitte, *Re: Assistance with review of Power and Water Commission's (PWC) pricing principles, pricing proposal and capital contributions policy (Advice to the Utilities Commission),* 12 December 2013, p. 13-14.

64 Utilities Commission, *2014-2019 Network Price Determination – Framework And Approach Decision Paper*, November 2012, p. 47.

65 Ibid, p. 42.

10 Forecast operating and maintenance expenditure

This section of the Proposal sets out Power Networks' proposed forecast of operating and maintenance expenditure (opex), for incorporation in the calculation of allowable revenue in section 15.

10.1 Commission's Draft Determination

The Initial Regulatory Proposal contained Power Networks' proposed opex forecast and supporting material.

The Commission engaged consultant Parsons Brinckerhoff to assess the prudency and efficiency of Power Networks' forecast operating and maintenance expenditure. Parsons Brinckerhoff undertook a high level review of each opex category (Metering, Specific Maintenance, etc), and recommended specific adjustments to the forecast.

The original review included a recommendation from Parsons Brinckerhoff that the Commission adjust the total operating and maintenance expenditure of Power Networks downward by 6 per cent[66]. The Commission sought further advice on benchmarking from Parsons Brinckerhoff and used this advice as the basis to propose an additional non-specific "efficiency adjustment" to reduce Power Networks' opex *"closer to the average achieved by its peers"*[67].

The overall reduction in operating expenditure proposed by the Commission over the 2014-19 regulatory control period was from $539 million to $481 million, or 11 per cent [68], as demonstrated in the table below.

Table 10.1 – Operating Expenditure ($million, real $2013/14)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
PWC Initial Regulatory Proposal	$109.3	$107.2	$108.6	$107.4	$106.9	$539.3
UC Draft Determination	$102.2	$98.5	$97.7	$92.9	$90.2	$481.5

10.2 Efficiency adjustment

Power and Water considers that the unallocated efficiency adjustment applied by the Commission to be arbitrary. Power and Water considers that the expenditure it has proposed to be both prudent and efficient.

66 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, p xi.

67 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, December 2013, p. 9.

68 Ibid, p. 98.

Power and Water engaged Huegin Consulting Group (Huegin) to review the benchmarking analysis that forms the basis of the Commission's efficiency adjustment[69].

10.2.1 Huegin Benchmarking Analysis (2014)

Huegin concluded that *"the benchmarking analysis presented in support of the recommendation to reduce Power Networks' operating expenditure is neither robust nor sufficiently accurate to justify the adjustment. The limitations of partial productivity benchmarks are well documented, and the inherent levels of inaccuracy and uncertainty in the techniques are greater in aggregate than the fidelity of the recommended adjustment."*[70]

Huegin presented the following evidence in support of its conclusion:

1. *"Benchmarking on partial productivity indices has well documented limitations - these are amplified when applied to a business such as Power and Water;*
2. *The selection of the type of regression line with the aim of achieving a higher correlation coefficient, rather than a defensible relationship between the independent and dependent variables, highlights the subjective nature of the analysis;*
3. *The selection of comparators in the sample has a significant influence on the fit and position of the "industry average trend line";*
4. *The exclusion of the Power Networks data from the regression analysis illustrates the inadequacy of using the benchmarking analysis to evaluate the Power Networks opex - other businesses were excluded where they were not shown to contribute to an increased correlation coefficient on the basis that they were not considered peers, whereas the same indication for Power Networks has been assessed as inefficiency;*
5. *The comparison of opex over different periods renders the analysis unsuitable; and*
6. *The fact that respective recommendations for an opex adjustment of 6% and 27% are based on separate analyses of the same data and benchmarks by the same analysts is indicative of the degrees of freedom possible in inferring relative efficiency from what is otherwise data error, statistical noise and sampling bias and heterogeneity."*[71]

Power Networks' revised proposal

Power Networks has not adopted the overall reduction in opex proposed by the Commission over the 2014-19 regulatory control period. The full justification for this is contained in Huegin's Report at Attachment 10.

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69 Huegin Consulting, *Review of Benchmarking Methods Applied*, January 2014.

70 Ibid, p. 3.

71 Ibid, p. 3.

10.3 Operating expenditure development process

An overview of Power Networks' operating expenditure development process was provided as part of the Initial Regulatory Proposal. This material is not restated in this Proposal.

Power Networks reviewed each individual amendment that was recommended by Parsons Brinckerhoff, and adopted by the Commission, and accepts some, but not all, of the associated operating expenditure adjustments. The following sections focus on those projects amended by the Commission, with reference to Parsons Brinckerhoff's report, and do not restate the summaries of those projects that were included in the Initial Regulatory Proposal and accepted by the Commission.

10.4 Strategy and Planning and Service Delivery opex

The Strategy and Planning group is responsible for Power Networks' strategy and planning functions, including asset management, network planning development, and investment analysis, and is also substantially responsible for the delivery of the major capital program. The Service Delivery group is responsible for the delivery of Power Networks' maintenance and various capital work programs.

Both the Strategy and Planning and Service Delivery Opex are forecast to increase slightly in the forthcoming regulatory control period, mostly based on additional personnel Power Networks considers it requires over the period.

Commission's Draft Determination

The Commission did not approve the forecast Service Delivery opex and states *"the UC considers that the forecast service delivery opex should be reduced to remove the 'Other – Remainder' amount."*[72] The Commission also did not approve the forecast Strategy and Planning opex for the same reason[73].

Parsons Brinckerhoff's recommendation was that, while they were satisfied that most of the expenditure forecast for the Service Delivery and Strategy and Planning opex categories represent prudent and efficient costs, Power Networks did not provide justification for the Remainder line item in the 'Other' cost build up[74].

The Commission has reduced the Service Delivery opex forecast by $8 million, and the Strategy and Planning opex forecast by $5.75 million for this adjustment.

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72 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, December 2013 p. 88.

73 Ibid, p. 89.

74 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, p. 122 and 125.

Power Networks proposal

Power and Water notes the following in relation to the adjustments applied by the Commission:

- Table 2.1.3 in the relevant RIN Template did not require this additional information;
- In relation to the Service Delivery opex adjustment, it appears that Parsons Brinckerhoff has taken the forecast 'Other – Remainder' amount for 2013-14 ($1.6 million) and applied that as an annual reduction in the forthcoming regulatory control period; and
- In relation to the Strategy and Planning opex adjustment, it is unclear what Parsons Brinkerhoff has based the annual reduction on, as the forecast 'Other – Remainder' amount for 2013-14 is $0.57 million and Parsons Brinkerhoff applied $1.15 million as the annual reduction in the forthcoming regulatory control period.

Parsons Brinckerhoff acknowledge that *"Power Networks did not have an opportunity to provide further clarification of the Remainder category expenditure within the timeframe of this review, however, with the information available we are unable to conclude that this expenditure is prudent or efficient and recommend it is excluded from the expenditure allowance"*[75]. Power Networks welcomes the opportunity to provide additional information to support its original proposal for the Commission's consideration.

The 'Other – Remainder" expenditure is made up of cost items such as:

- Safety & Health Expense;
- Uniforms and Protective Clothing;
- Freight;
- Furniture & Fittings;
- Plant & Equipment; and
- Recruitment.

Power Networks has not adopted the recommended adjustments to Service Delivery and Strategy and Planning opex, as it considers that that this expenditure is necessary over the forthcoming regulatory control period.

10.5 Metering opex

Power and Water's Power Networks' Metering Services group supplies electricity metering provision, and electricity and water meter data services. Expenditure on water meter data services is incurred by Power and Water's Water Services business unit, and has been excluded from Power Networks expenditure forecasts.

[75] Ibid, p. 121.

The Metering opex forecast is required to supply the required level of metering services to Power Networks, and to enable compliance with regulatory and statutory obligations.

The Metering opex forecast submitted with Power Networks' Initial Regulatory Proposal included an increase of eleven additional positions in Power Networks' Metering Services' workforce, to bring Metering Services up to the standard of a modern metering business. The number of existing and additional metering staff was recommended in an independent review by Phacelift consultants conducted in 2012.

Commission's Draft Determination

The Commission did not approve the Metering opex forecast. The Commission accepted PB's recommendation that nine new positions should be sufficient to support the creation of the eleven full time roles identified in the Initial Regulatory Proposal.[76]

Power Networks' revised proposal

Power Networks has adjusted the Metering opex forecast in accordance with the Commission's Draft Determination.

10.6 Regulatory Costs opex

Power Networks' Initial Regulatory Proposal contained a proposal for increased costs of additional staffing, to adequately comply with existing and new regulatory obligations under the Rules framework. This proposal comprised two additional full-time resources to undertake regulatory compliance (a Regulatory Compliance Manager and a Regulatory Reporting Officer). This element of the opex forecast also included the costs to prepare for Power Networks' 2019 Networks Price Determination.

Commission's Draft Determination

Parsons Brinkerhoff proposed a reduction to the Regulatory Costs opex forecast as it held the view that many of the regulatory functions are already undertaken by the Network Management group and one Full Time Employee (FTE) would be sufficient to address any new regulatory requirements[77]. In the Draft Determination, the Commission accepted this advice and reduced the additional regulatory costs to represent one additional resource, on the basis that the proposed staffing level was inefficient[78].

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76 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, p. 129.

77 Ibid, p. 136-137.

78 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, p. 89-90.

Power Networks' revised proposal

Power Networks does not accept that the Commission's proposal in relation to reducing the regulatory costs forecast is reasonable.

Cabinet has approved a package of reforms for the Northern Territory electricity market, including application of relevant parts of the National Electricity Law (NEL) and the Rules for the economic regulation of distribution networks to be adopted by the Northern Territory from 1 July 2014[79]. As part of these reforms, responsibility for the economic regulation of Power Networks will be transferred from the Commission to the AER during the next regulatory control period, under transitional arrangements still to be developed.

Whilst the Commission had been progressively implementing the provisions of the Rules, to the extent they were compatible with the Northern Territory legislation and Power and Water's capabilities, this transition to the Rules framework will clearly take place over a more compressed timeframe.

Power Networks' transition to the Rules framework is expected to involve the development of formalised transitional Rules clauses or derogations and will also involve the review of relevant Northern Territory legislation. There will be an extended period of negotiation, over which the terms of the transition and the rate of adoption of NEM processes will be established. This negotiation will rely heavily upon supporting information that will be provided by Power Networks personnel and collated by the Networks regulatory officers.

The Rules framework brings with it a host of additional obligations with which Power Networks will need to comply:

- Regulatory reporting in the RIN format (as varied from time to time by the AER). This will need to be completed monthly and reported annually;
- Reporting in the new RIN benchmarking template proposed by the AER[80];
- The annual preparation of a Distribution Annual Planning Report and associated demand side engagement obligations, as required by clauses 5.13.1 and 5.13.2 of the Rules;
- Compliance with the provisions of the Regulatory Investment Tests (RIT-T or RIT-D), as appropriate;
- Compliance with and reporting for the AER's incentive schemes (the STPIS, EBSS and DMIS);
- Transition to the AER's post-tax regulatory framework, with the formation and maintenance of a Taxation Asset Base; and

[79] David Tollner (NT Treasurer), *Letter from the Treasurer re NPD and application of NER*, November 2013.

[80] AER, *Better regulation - Explanatory statement - Regulatory information notices to collect information for economic benchmarking,* November 2013.

- Compliance with the AER's guidelines and reporting arrangements (Information requirements, Cost allocation, Ring fencing, Pricing methodology, Submissions, Performance reporting, Expenditure forecasting, Shared assets, Consumer engagement).

Within Power Networks, the information to support the development of these transitional arrangements and the additional reporting will in most cases be produced by personnel 'at the coal face', using existing or modified information systems. However, the coordination of these information requirements, ensuring timely regulatory reporting and reporting regulatory compliance will clearly be a very significant task. Moreover, the communication of these regulatory requirements to Power Networks' personnel and raising their awareness of regulatory obligations is a task that will be carried out by regulatory personnel within Power Networks.

Power Networks considers the magnitude of this additional regulatory reporting burden and compliance obligations to be well beyond the capability of a single officer.

Therefore Power Networks has not adopted the recommended adjustment to Regulatory Costs opex, as it considers that that this expenditure is necessary over the forthcoming regulatory control period.

10.7 GSL Costs opex

The GSL Costs opex forecast has two components:

- GSL Payments – forecast GSL payments to customers; and
- GSL Operating Costs – relating to the on-going administration, reporting and customer interaction associated with the GSL Scheme.

In its Initial Regulatory Proposal, Power Networks noted that the forecast expenditure would be updated in its Revised Regulatory Proposal based on the recently approved electricity service standard targets under the 2012 NT Electricity Standards of Service Code (ESS Code). These targets were approved on 12 July 2013, and Power Networks did not have sufficient time to review the forecast to determine the impact on the Feeder Upgrade capital expenditure program and the Vegetation Management maintenance expenditure program contained in the Initial Regulatory Proposal, which in turn impacts on the forecast level of GSL Payments.

Commission's Draft Determination

The Commission did not approve the GSL costs opex forecast and states "*the UC considers that the forecast GSL costs opex should be reduced to levels commensurate with average reliability performance that meets the standards set by the UC under the ESS Code*".[81]

[81] Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, p. 91.

Power Networks' revised proposal

Power Networks has not adopted the Commission's adjustments to the GSL Costs opex forecast. In line with the Commission's recommendation, Power Networks has assessed the impact on the forecast expenditure of the revised Electricity Standards of Service targets approved by the Commission under the 2012 NT Electricity Standards of Service Code, and has revised the forecasts accordingly.

The revised GSL Cost opex justified against the Operational Expenditure Objectives and Criteria is included at Confidential Attachment 13.

10.8 System Operations opex

This program seeks to continue the provision of System Operations services to the Networks business. Those services are the subject of a Service Level Agreement (SLA) between the Power Networks and System Control business units.

Commission's Draft Determination

The UC did not approve the system operations opex and states that *"the forecast system operation opex should be reduced to remove the costs associated with non-regulated networks"*[82].

Power Networks' revised proposal

Power Networks has not adopted the recommended adjustment to the System Operations opex forecast, as non-regulated expenditure has been specifically excluded from the capital, operating and maintenance expenditure forecasts. Power Networks' regulated and non-regulated expenditure and revenue are posted to separate general ledger financial accounts, as per Power Networks' Cost Allocation Method.

An analysis of the SLA calculations was submitted by Power and Water to Parsons Brinkerhoff as part of the prudency and efficiency review, to demonstrate how all of System Controls costs are allocated to each of the relevant business units (Generation, Water Services, Remote Operations, Retail and Power Networks regulated and non-regulated). However, only the Power Networks regulated component has been included in Power Networks opex forecasts. Therefore Power Networks has not adopted the recommended adjustment to System Operations opex.

10.9 Forecast operating expenditure

The revised forecast operating expenditure for the 2014-19 regulatory control period is shown in Table 10.2.

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[82] Ibid, p. 90.

Table 10.2 - Operating expenditure ($ million, real $2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Revised Regulatory Proposal	$67.6	$66.6	$64.9	$66.2	$65.7	$331.0

10.10 Maintenance expenditure development process

The development of the operating expenditure forecasts was described in the Initial Regulatory Proposal. This material is not repeated in this Proposal. In the sections following, variations to the components of the expenditure forecast are treated in turn.

10.11 Preventative maintenance

Preventative maintenance is defined by Power Networks as maintenance conducted periodically that is designed to prevent asset failures and capture asset condition. Vegetation management is part of preventative maintenance, however this is discussed separately in section 10.4.2.

Commission's Draft Determination

The Commission and Parsons Brinkerhoff considered the preventative maintenance expenditure forecast to be prudent and efficient. However, the following amendments were made[83]:

- As a result of the deferral of capital replacement projects which were the basis for the forecast, Parsons Brinkerhoff recommended adjustments to the forecast to account for additional preventative maintenance that will be required over the period; and
- The RLS testing portion of the Distribution Pole Extension sub-program was reallocated from capital expenditure (Sub8274 Asset Replacement and Upgrade Program) to maintenance expenditure.

Therefore, the Commission did not approve the expenditure forecast and increased the forecast to allow for additional costs arising from deferral of replacement capital expenditure and the reallocation of capital expenditure[84].

Power Networks' revised proposal

Power Networks has adjusted the preventative maintenance expenditure forecast in accordance with the Commission's Draft Determination in recognition of the additional maintenance expenditure required due to the deferral of replacement

83 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, p. 144.

84 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, p. 93.

capital expenditure projects and the reallocation of the capital expenditure, also discussed in section 8.

10.12 Vegetation management

The vegetation management expenditure forecasts are based on historical expenditure and associated reliability trends due to vegetation related outages, and improvements required to meet reliability targets and improve the resilience of the network during intense storms, rainfall and cyclones.

In its Initial Regulatory Proposal, Power Networks noted that the forecast expenditure for vegetation management would be updated in its Revised Regulatory Proposal based on the recently approved electricity service standard targets under the ESS Code. These targets were approved on 12 July 2013, and Power Networks did not have sufficient time to review the forecast to determine the impact on the vegetation management maintenance expenditure program contained in the Initial Regulatory Proposal.

Commission's Draft Determination

The Commission considered that the need for reliability improvement through vegetation management had not been established by Power Networks, and that an increase is not justified and that vegetation management opex should be reduced to current levels[85].

Power Networks' revised proposal

Power Networks has not adopted the Commission's adjustments to the Vegetation Management expenditure forecast. Power Networks has assessed the impact of the revised Electricity Standards of Service targets approved by the Commission under the 2012 ESS Code on the expenditure forecast and has revised the expenditure accordingly.

The revised vegetation management expenditure justified against the Operational Expenditure Objectives and Criteria is included at Confidential Attachment 13.

10.13 Planned and unplanned corrective maintenance

Corrective maintenance is performed on assets to restore them to an acceptable condition so that they can be operated at their required capacity reliably and safely.

Planned corrective maintenance is defined as activities performed when a conditional failure or "defect" of an asset is identified. Corrective maintenance is performed on the asset prior to it suffering a functional failure or "fault" resulting in loss of supply to customers or network security being compromised.

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85 Ibid, p. 93.

Unplanned corrective maintenance (fault maintenance) is performed on assets when a functional failure occurs resulting in the loss of supply to customers. The immediate priority is to restore supply to customers and reinstate network security to planned levels, by repairing the asset that has failed.

Commission's Draft Determination

The Commission considered that Power Networks' approach to forecast planned corrective maintenance was reasonable, however the Commission considered that Power Networks did not clearly justify the change in defect growth rates. The Commission accepted Parsons Brinkerhoff's recommendation to remove the expenditure associated with the defect rate of change and to retain the expenditure at the historical average, and to allow for additional costs associated with the deferral of zone substations capital works projects, which were the basis for the forecast[86].

The Commission considered that Power Networks' approach to forecast unplanned corrective maintenance was reasonable. However, as a result of adjustments to the zone substations capital works projects which were the basis for the forecast, Parsons Brinkerhoff recommended adjustments to the forecast to account for additional maintenance that will be required over the period[87]. Therefore, the Commission did not approve the expenditure forecast and increased the forecast to allow for additional costs arising from deferral of the capital works projects[88].

Power Networks' revised proposal

Power Networks has adjusted the planned corrective maintenance and unplanned corrective maintenance expenditure forecasts in accordance with the Commission's Draft Determination.

10.14 Specific maintenance

Specific maintenance is a type of corrective maintenance that addresses a specific issue that is found across a class of assets. The need for specific maintenance is identified through the analysis of asset condition data or through long term trends of failures in particular classes of assets, as opposed to being identified on a day-to-day basis through preventative maintenance tasks.

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86 Ibid, p. 93.

87 Parsons Brinkerhoff, *Utilities Commission of the Northern Territory 2014-2019 Network Price Determination – Review of Power and Water Corporation's regulatory proposal for the 2014-2019 regulatory period*, 18 December 2013, p. 154.

88 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, p. 94.

Commission's Draft Determination

The Commission considered that the forecast specific maintenance expenditure should be decreased to remove the costs of decommissioning of assets where the associated replacement capital expenditure has been deferred[89].

Power Networks' revised proposal

Power Networks has accepted the Commission's decision to remove the decommissioning costs for Berrimah Zone Substation as Power Networks has accepted revised timing for Berrimah Zone Substation. The project's completion date is now 2018-19 as opposed to 2016-17 and therefore the zone substation will be decommissioned post 2018-19.

10.15 Forecast maintenance expenditure

The revised forecast maintenance expenditure for the 2014-19 regulatory control period is shown in Table 10.3.

Table 10.3 - Maintenance expenditure ($ million, real $2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Revised Regulatory Proposal	$38.9	$38.6	$42.2	$38.5	$38.9	$197.1

10.16 Operating and maintenance expenditure in the 2014-19 regulatory control period

The total revised forecast operating and maintenance expenditure for the 2014-19 regulatory control period is shown in Table 10.4.

Table 10.4 - Operating and maintenance expenditure ($ million, real $2013/14 and escalated)

Year	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Operating expenditure	$67.6	$66.6	$64.9	$66.2	$65.7	$331.0
Maintenance expenditure	$38.9	$38.6	$42.2	$38.5	$38.9	$197.1
Operating and maintenance expenditure	$106.4	$105.3	$107.1	$104.7	$104.6	$528.1

This operating and maintenance expenditure has been used in the NTRM to determine Power Networks' revenue requirement and prices described in section 15.

89 Ibid, p. 94.

11 Service standards framework

This section describes how Power Networks will comply with the service standards established by the Commission for the 2014-19 regulatory control period.

11.1 Commission's Draft Determination

The Commission's Draft Determination recommended that the standards of quality, reliability and security of supply that are to be delivered in the forthcoming regulatory control periods are the standards established in the Commission's Electricity Standards of Service Code (ESS Code) and Guaranteed Service Level Code (GSL Code).

The ESS Code establishes services and performance measures for network service providers. The ESS Code sets out the process and obligations for establishing, amending and meeting the approved target standards.

On 12 July 2013, the Commission approved the distribution and transmission network performance target standards applicable to Power Networks for the forthcoming regulatory control period. The Commission set distribution targets using an improvement factor of:

- 5 percent applicable to CBD, urban and short rural feeders; and
- 10 per cent applicable to long rural feeders.

The GSL Code sets out the arrangements for payments by network service providers to small customers who receive poor levels of service. GSL payments are not intended to be compensation but rather some recognition for poor service.

11.2 Service standard framework

There are two elements to the service standards framework to which Power Networks is subjected. These are the GSL Code, and the network reliability standards set out in the ESS Code.

11.2.1 Guaranteed Service Levels

The GSL Code took effect from 1 January 2012, with a staged approach to the implementation of payments for various service performance measures. The GSL Code was fully implemented on 1 July 2012.

11.2.2 Network reliability standards

Power and Water capital, operating and expenditure justifications for vegetation management and reliability improvement are based on the new ESS Code. A clear need to improve performance in order to meet the new mandated standards through increased vegetation management and feeder upgrades is demonstrated in the justification.

11.3 Power Networks' service performance

This section sets out Power Networks' historic service performance and its proposal for network performance during the 2014-19 regulatory control period. As foreshadowed in Power Networks' Initial Regulatory Proposal, the service performance has been restated in terms of the targets approved by the Commission under the ESS Code.

11.3.1 Service performance during the 2009-14 regulatory control period

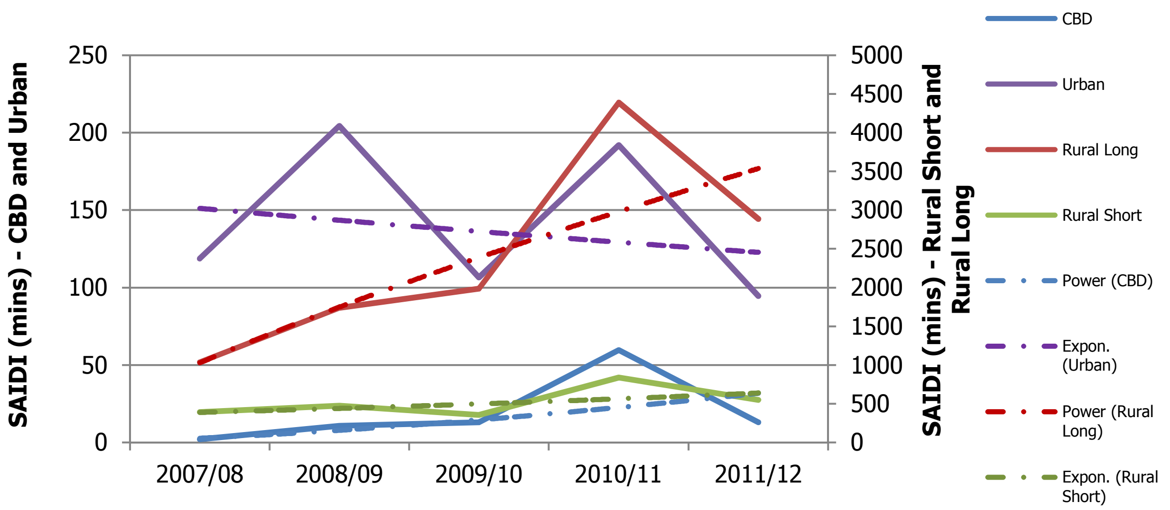
The SAIDI and SAIFI target standards set by the Commission in their July 2013 determination represent the acceptable level of reliability for the distribution network. These target standards are segmented by feeder categories as shown in Table 11.1.

Table 11.1 – ESS Code: Network Performance Target Standards

Feeder Category	Distribution Target Standards	
	SAIDI (mins)	SAIFI
CBD	18.8	0.4
Urban	136.0	2.5
Rural Short	496.3	8.1
Rural Long	2,164.9	35.1

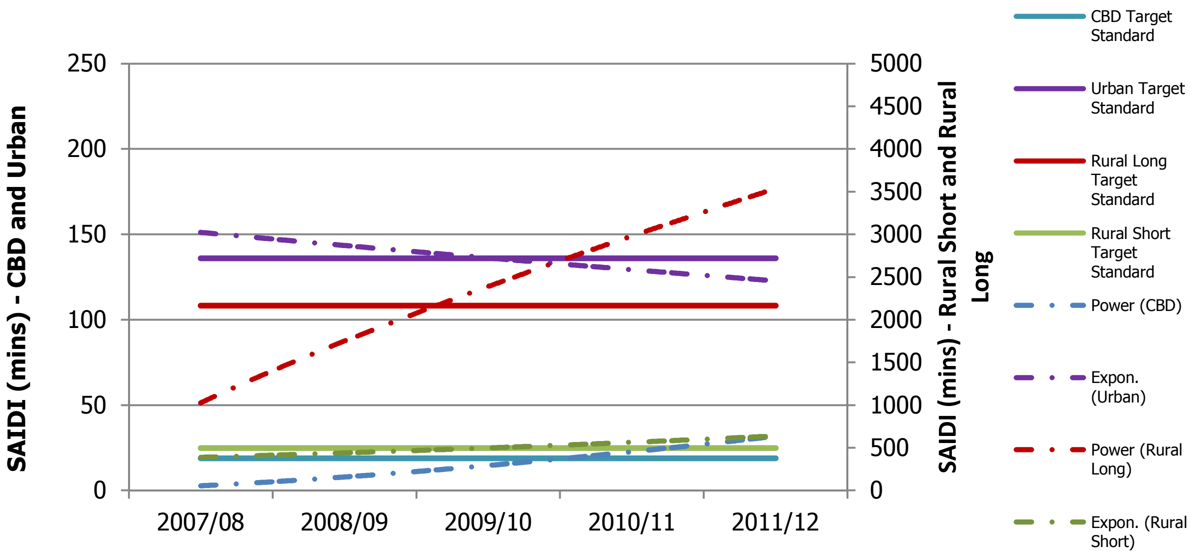
As demonstrated in Figure 11.1, reliability in three out of the four feeder categories (CBD, Rural Long and Rural Short) for SAIDI has deteriorated over the last five financial years. The upward trends in the three feeder categories exceed the acceptable level of reliability for the network. The trend line type that results in the best correlation is used to trend the reliability data in each feeder category.

Figure 11.1 – Feeder Category: SAIDI 5 year trends



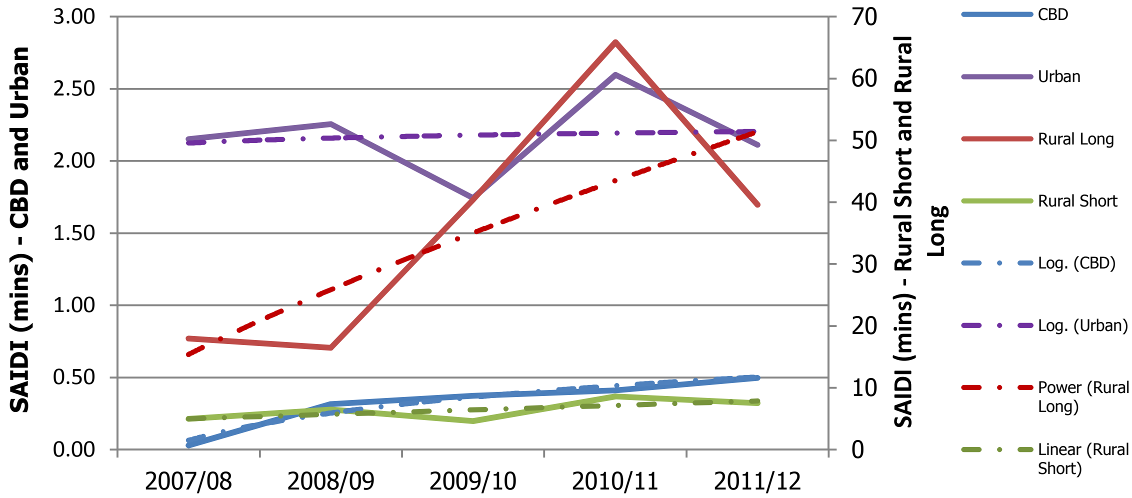
Trends in three of the four feeder categories (CBD, Rural Short and Rural Long) exceed their corresponding SAIDI target standards, as demonstrated in Figure 11.2. Power Networks is required to return the network reliability in each category to levels below the target standards. A five-year feeder upgrade program should achieve a reduction in feeder category SAIDI from current levels to the target standard.

Figure 11.2 – Feeder Category: SAIDI 5 year trends against target standards



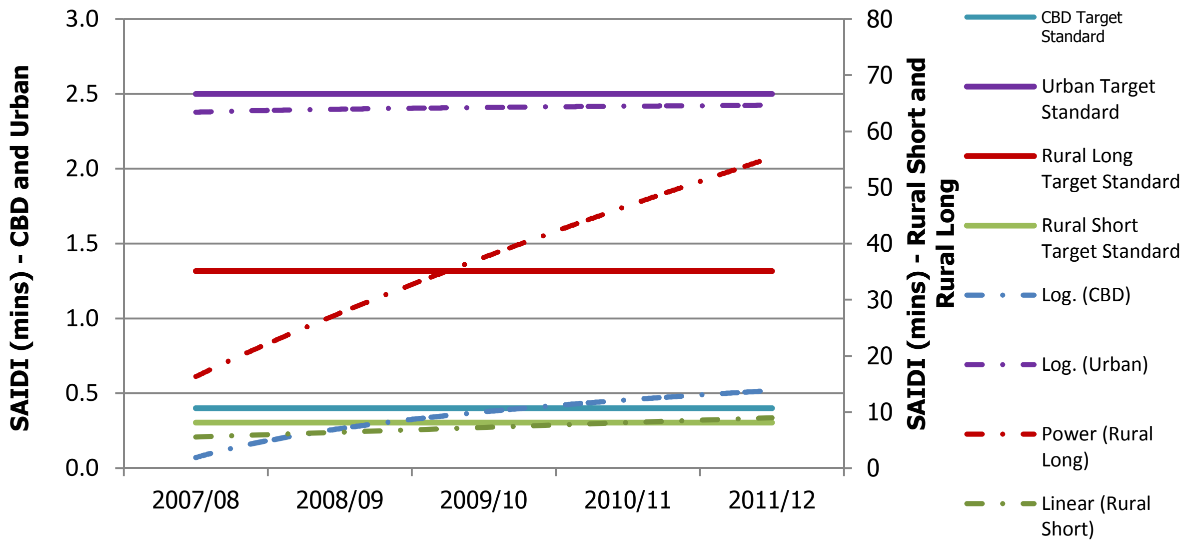
Reliability in three out of the four feeder categories (CBD, Rural Short and Rural Long) for SAIFI has deteriorated in recent years, as demonstrated in Figure 11.3. The upward trend in these three feeder categories exceeds the acceptable level of reliability for the network.

Figure 11.3 – Feeder Category: SAIFI 5 year trends



SAIFI trends in each of the four feeder categories exceed their corresponding target standards, as shown in Figure 11.4. Power Networks is required to return the network reliability in each category to levels below the target standards. A five-year feeder upgrade program should achieve a reduction in feeder category SAIFI from current levels to the target standard.

Figure 11.4 – Feeder Category: SAIFI 5 year trends against target standards



2012/13 performance data is now available and has been tabled below. The Bureau of Meteorology states that the 2012/13 wet-season was abnormally dry and hot with the monsoon starting later than normal in mid-January 2013[90]. The dry periods during this year resulted in improved reliability performance. Therefore, Power Networks met the distribution target standards in three out of the four feeder categories (Table 11.2) in 2012/13.

Table 11.2 – 2012-13 Distribution SAIDI: results segmented by feeder category (adjusted)

Feeder Categories	Adjusted SAIDI Target Standard (minutes)	Adjusted SAIDI 2012-13 Results (minutes)	Target Standard Met?
CBD	18.8	1.1	Yes
Urban	136.0	111.0	Yes
Rural Short	496.3	536.9	No
Rural Long	2,164.9	1,108.7	Yes

90 Bureau of Meteorology, _Seasonal Climate Summary for the Northern Territory_, 1 May 2013 (http://www.bom.gov.au/climate/current/season/nt/archive/201304.summary.shtml).

Power and Water met the SAIFI target standards in three out of the four feeder categories, as shown in Table 11.3 below.

Table 11.3 – 2012-13 Distribution SAIFI: results segmented by feeder category (adjusted)

Feeder Categories	Adjusted SAIFI Target Standard	Adjusted SAIFI 2012-13 Results (minutes)	Target Standard Met?
CBD	0.4	0.03	Yes
Urban	2.5	2.5	Yes
Rural Short	8.1	9.1	No
Rural Long	35.1	12.2	Yes

11.3.2 Service performance during the 2014-19 regulatory control period

To meet the target standards set out by the ESS Code, an improvement in SAIDI by feeder category is required in the 2014-19 regulatory control period, particularly for the Rural Long feeder category. The 2011/12 SAIDI trend value, the SAIDI target standard and the required SAIDI improvement is shown in Table 11.4.

Table 11.4 – 2011/12 SAIDI trend, target standard and required improvement

Feeder Category	2011/12 Trend Value (mins)	SAIDI Target Standard (mins)	Required SAIDI Improvement (mins)
CBD	32	18.8	13.2
Urban	123	136.0	0
Rural Short	680	496.3	183.7
Rural Long	3,550	2,164.9	1,385.1

To meet the Target Standards set out by the ESS Code an improvement SAIFI by feeder category SAIFI is required, particularly for the Rural Long feeder category. The 2011/12 SAIFI trend value, the SAIFI target standard and the required SAIFI improvement is shown in Table 11.5.

Table 11.5 – 2011/12 SAIFI trend, target standard and required improvement

Feeder Category	2011/12 Trend Value	SAIFI Target Standard	Required SAIFI Improvement
CBD	0.7	0.4	0.3
Urban	2.4	2.5	0
Rural Short	9.5	8.1	1.4
Rural Long	55.7	35.1	20.6

Power Networks' annual Feeder Upgrade Program and the Vegetation Management Program are required in order to achieve the target standards by the end of the 2014-19 regulatory control period, and thus improve reliability. SAIDI and SAIFI trends for all feeder categories over the previous five years and the forecast SAIDI and SAIFI performance during the 2014-19 regulatory control period are shown in Figure 11.5 and Figure 11.6.

Figure 11.5 – Feeder Category: SAIDI 5 year trends and forecasts

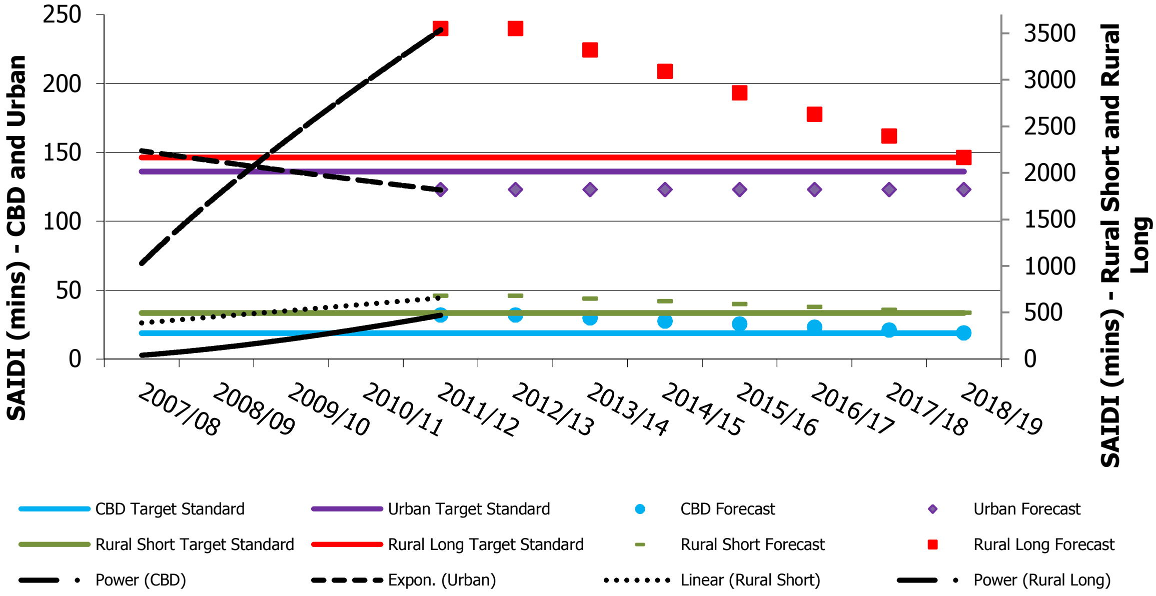
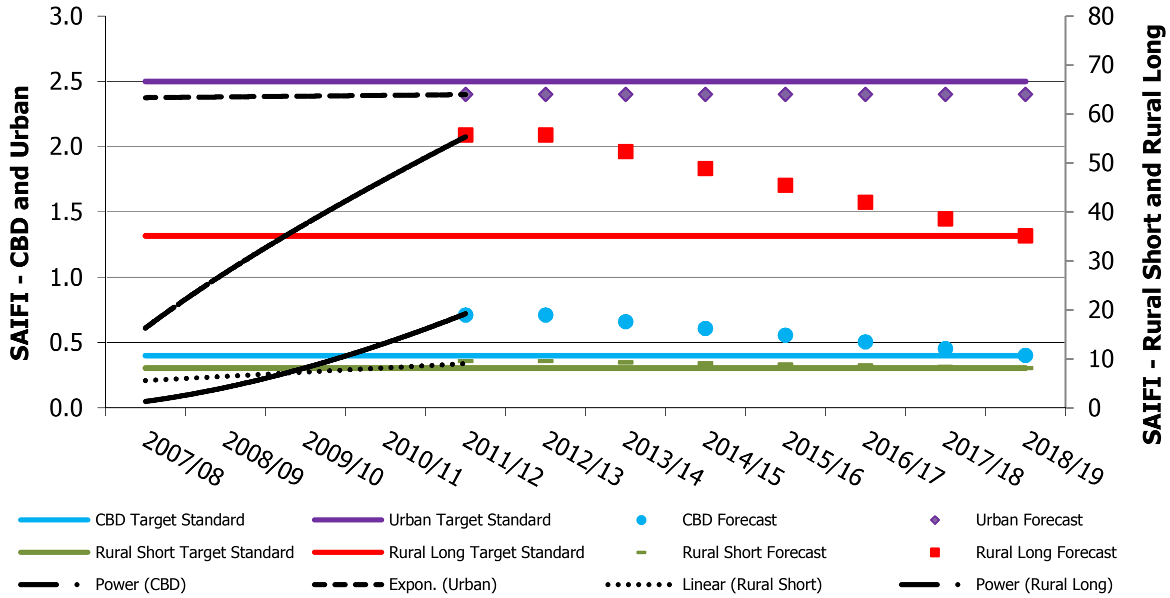


Figure 11.6 – Feeder Category: SAIFI five year trends and forecasts



Feeder Upgrade Program

Power Networks' Feeder Upgrade Program targets poorly performing areas on the distribution network. Each year Power Networks develops feeder performance reports for poor performing feeders. These reports include analysis of five years of historical outage data and interruption causes. The results of the analysis drive targeted feeder upgrades planned for the upcoming financial year.

Feeder performance is continually monitored to determine the success of the feeder upgrades and improvement works. Typical works requested on the poorly performing feeders as a part of the Feeder Upgrade Program include:

Hardware upgrades

Hardware upgrades include the replacement of insulators, the installation of fibreglass cross arms, conductor spacers and the installation of bat guards. These measures are expected to minimise interruptions due to lightning and animal interference on poorly performing feeders.

Network reconfigurations including recloser installation

On poorly performing feeders prone to transient faults caused by vegetation, weather and/or animals, auto-reclosing at key network locations reduces the outage impact and improves restoration times, through greater sectionalisation and remote operation. Gas circuit reclosers are being installed on selected, poorly performing feeders to achieve this outcome.

Air break switch to gas break switch changeovers

Air break switches are changed over to remotely controlled gas break switches in strategic locations, to improve interruption restoration times. Poorly performing feeders with high interruption durations have been targeted for this program.

Cable testing and replacement

High voltage cables are tested and condition assessed to determine if replacement is required. Cables with more than two or three failures are scheduled for replacement. Poorly performing feeders with a high incidence of cable failures have been targeted for priority testing and replacement programs.

For further information on the Feeder Upgrade Program, refer to Confidential Attachment 12.

Vegetation Management Program

The Vegetation Management Program includes tree trimming in four main areas; the Darwin urban area; the Darwin rural area; the Katherine region; and the southern region. The program includes increased trimming efforts in previous problem areas as identified in the annual Feeder Upgrade Program, and slashing and mulching in key locations to minimise vegetation regrowth. Vegetation growth rates vary widely across the Northern Territory.

The trimming works are performed by specialist contractors and contractor performance is monitored against an annual maintenance schedule to ensure all feeders are adequately maintained in all regions.

In the southern regions around Alice Springs and Tennant Creek, feeders undergo a detailed annual vegetation inspection in order to identify the areas requiring maintenance. In the northern regions around Katherine and Darwin, these inspections are performed bi-annually due to the rapid re-growth that occurs during the wet season. Vegetation contractors use specialised trimming and mulching equipment in rural areas to reduce the risk of vegetation damage to lines during the wet season as far as practical. Many areas of the rural network can only be accessed by helicopter during monsoon periods, and only light vehicles can access large portions of the rural network for several months after the conclusion of the wet season.

The targeting of problem areas has been a focus in the last two years as outage data quality has improved. When resources are available, these areas can be given additional focus in an effort to further limit reliability issues during the wet season.

For further information on the Vegetation Management Program, refer to Confidential Attachment 13.

12 Regulatory asset base

Network businesses are asset intensive and the regulatory asset base (RAB) is an important component of the building block revenue, in that it affects both the return on and return of assets. The return on capital is the asset value multiplied by the WACC, while the return of capital is the depreciation component of revenue. Taken together, these components typically represent the majority of the network revenue.

In the Initial Regulatory Proposal, Power Networks advocated the adoption of Optimised Depreciated Replacement Cost (ODRC) as the approach to asset valuation for the 2014 Networks Price Determination, rather than the roll forward of the asset base that had been determined by the Commission in an off-ramp decision in 2005. This approach is consistent with the asset valuations of other network businesses when transferring to the Rules framework.

12.1 Asset valuation

In the Draft Determination, the Commission accepted the use of SKM's ODRC valuation as an appropriate basis on which to determine Power Networks' asset related costs. Power Networks strongly supports this decision and notes that this will align it with other network businesses that have transferred to the Rules regulatory framework.

12.2 Roll forward of the 2013 ODRC RAB value to 30 June 2014

Commission's Draft Determination

The Commission accepted the opening regulatory asset base included in Power Networks' Initial Regulatory Proposal and has determined that the opening regulatory asset base for Power Networks as at 1 July 2014 is $930.1 million[91].

Power Networks' revised proposal

Power Networks' has adopted an opening regulatory asset base value as at 1 July 2014 of $930.1 million, in line with the Commission's Draft Determination. This value is used in the NTRM as the basis for the roll forward of assets throughout the 2014-19 regulatory control period.

12.3 Roll forward of the RAB value from 1 July 2014 to 30 June 2019

Commission's Draft Determination

Based on an opening regulatory asset base of $930.1, the Commission determined a closing regulatory asset base as at 30 June 2019 of $1,056.07 million[92].

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[91] Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, p. 55.

[92] Ibid, p. 121.

Power Networks' revised proposal

The opening regulatory asset base of $930.1 million has been rolled forward throughout the 2014-19 regulatory control period. Power Networks adopted CPI increases of 2.51 per cent per annum in the NTRM, as per the Commission's Draft Determination and has updated the NTRM for the 2014-19 forecast capital expenditure as proposed in section 8.7.

The outcome of rolling forward the regulatory asset base throughout the 2014-19 regulatory control period is shown in Table 12.1.

Table 12.1 – RAB roll forward – annual closing RAB ($ million, nominal)

Year	2014/15	2015/16	2016/17	2017/18	2018/19
RAB	$981.6	$1,019.1	$1,039.0	$1,055.0	$1,087.3

13 Weighted average cost of capital

The Weighted Average Cost of Capital (WACC) is used to determine Power Networks' return on assets throughout the 2014-19 regulatory control period. It is therefore an important component in determining the allowable revenue.

In its Framework and Approach paper[93], the Commission proposed the WACC parameters to apply in the 2014 Determination. The Commission proposed to base the Debt Risk Premium (DRP) on a BBB+ credit rating, estimated from observed market data. This approach had been chosen by the AER for the Aurora draft determination but was subsequently overturned by the Competition Commission in favour of a BBB credit rating estimated from Bloomberg Fair Value Curves (FVC)[94]. Power Networks' Initial Regulatory Proposal proposed the latter approach. Using the market parameters for the Aurora final determination[95], the WACC determined from these parameters is compared in columns 2 and 3 of Table 13.1.

13.1 Commission's Draft Determination

In the draft determination, the Commission has accepted the use of the Bloomberg FVC for a BBB credit rating. However, it has chosen to use an Equity beta of 0.7, as discussed in the AER's Equity Beta Issues Paper[96]. These parameters are shown in column 4 of Table 13.1, with the market related parameters in this case from the AER's most recent SP Ausnet transmission decision[97].

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93 Utilities Commission, *2014-2019 Network Price Determination – Framework and Approach Decision Paper*, November 2012.

94 Australian Competition Tribunal, *Application by Envestra Ltd (No 2) [2012] ACompT 3,* 11 January 2012, paragraph 120; Australian Competition Tribunal, *Application by APT Allgas Energy Ltd [2012] ACompT 5,* 11 January 2012, paragraph 117; and Australian Competition Tribunal, *Application by United Energy Distribution Pty Ltd (No 2) [2012] ACompT 1*, 6 January 2012, paragraph 462.

95 AER, *Final Distribution Determination – Aurora Energy Pty Ltd, 2012-13 to 2016-17*, April 2012, p. 27 and 31.

96 AER, *Better Regulation – Equity beta issues paper*, October 2013.

97 AER, *Draft decision – SP AusNet Transmission determination 2014-15 to 2016-17*, August 2013.

Table 13.1 – WACC parameters

Parameter	Commission's Framework and Approach	Power Networks Initial Regulatory Proposal	Commission's Draft Determination
Nominal risk free rate	3.89%		4.13%[3]
Equity beta	0.8		0.7
Market risk premium	6.0%		
Gearing level (debt/debt plus equity)	60%		
Debt risk premium	3.14%[1]	4.11%[2]	3.00%[2]
Assumed utilisation of imputation credits (gamma)	0.25		
Inflation forecast (average)	2.60%		2.51%[4]
Pre tax nominal WACC	8.22%	8.80%	8.12%

1 10 year BBB+ based on observed market data.
2 Calculated using Bloomberg BBB rated FVC.
3 As per the AER's SP Ausnet draft determination.
4 As per the Commission's draft determination.

13.2 Power Networks' proposed WACC parameters

On 17 December the AER released the Rate of Return Guideline[98]. In this it confirmed that it proposes to use an Equity Beta estimate of 0.7 in its future decisions. Power Networks therefore accepts the Commission's draft determination on Equity beta. The outcome of using this parameter is shown in column 4 of Table 13.1.

Power Networks has used these parameters in calculating the proposed revenue requirement using the NTRM, as part of this Proposal. The market related parameters will be updated at the time of the Final Determination.

In addition, after discussions with the Commission, Power and Water discovered an inadvertent formula error in the effective tax rate for equity as part of the WACC calculation. The formula has been updated in the NTRM to align with the WACC calculation in the AER's Post-Tax Revenue Model. This change has resulted in a pre-tax nominal WACC of 9.05%.

98 AER, *Better Regulation – Rate of Return Guideline* , 17 December 2013.

14 Depreciation

This section sets out Power Networks' proposed depreciation and amortisation arrangements, and demonstrates that the proposed arrangements are consistent with the requirements of the Code and Rules. The return of capital is a building block component of the revenue requirement calculated in section 15.

14.1 Asset lives

In the Initial Regulatory Proposal, Power Networks' proposed asset categorisation and lives that differed from the 2009 Networks Price Determination but were aligned with the NEM practice, on the basis of the SKM's review of ODRC. The Commission accepted that the outcome of the SKM process was appropriate and accepted the asset categorisation and lives proposed by Power Networks.

14.2 Forecast regulatory depreciation for 2014-19 regulatory control period

Commission's Draft Determination

The Commission recalculated Power Networks' depreciation allowances for the forthcoming regulatory control period with a revised CPI, which resulted in a small increase in depreciation.

Power Networks' revised proposal

Table 14.1 contains the Power Networks' proposed regulatory depreciation for the 2014-19 regulatory control period. This has been derived from the NTRM and reflects the CPI chosen by the Commission in its Draft Determination and the revised capital expenditure profile, as proposed by Power Networks in section 8.7.

Table 14.1 - Depreciation for 2014-19 ($ million, nominal)

Year	2014/15	2015/16	2016/17	2017/18	2018/19
Depreciation	$28.5	$31.1	$27.0	$28.8	$31.1

The regulatory depreciation forms one of the building blocks to determine Power Networks' revenue, as described in section 15.

15 Indicative revenue and pricing for standard control services

In this section, Power Networks sets out the calculation of its Annual Revenue Requirement (ARR) for standard control services from the building block components.

On the basis of this ARR, the X factors are derived to provide a smoothed revenue trajectory in real terms.

This section outlines the derivation of allowable annual revenues, prices and the associated X factors, to meet the requirements of clause S6.1.3(6) of the Rules. The associated detail of all amounts, values and inputs relevant to the calculation is contained in other sections of this Proposal, its attachments and in the NTRM.

Both the revenues and prices presented in this section represent indicative numbers only, in that they are based upon:

- The WACC parameters used by the AER for the SP Ausnet transmission determination, with the exception of the Equity beta, as described in section 13. Power Networks accepts that the Commission will update the final parameters to those observed in a measurement period close to the time of the Final Determination; and
- Forecast energy volumes.

Network prices are set out in Power Networks' Pricing Proposal at Attachment 6.

Power Networks has identified that its estimate of 2013/14 tariff revenue (the last year of the current regulatory control period) provided in the Initial Regulatory Proposal was overstated, and has subsequently revised this estimate downwards. This has resulted in alteration of the proposed X factors. Further information is provided in Power Networks Pricing Proposal Model at Confidential Attachment 15.

15.1 Building block revenue components and annual revenue requirement

The NTRM has been used to calculate the revenue requirement for standard control services. The building block components and the total revenue are shown in Table 15.1.

Table 15.1 - Building block revenue (ODRC) for 2014-19 ($ million, nominal)

Year	2014/15	2015/16	2016/17	2017/18	2018/19
Return on capital	$84.14	$88.81	$92.20	$94.00	$95.45
Depreciation	$28.49	$31.15	$27.04	$28.81	$31.15
Operating and maintenance expenditure	$109.64	$111.21	$115.98	$116.25	$119.03
Carryover adjustment	$7.18	$7.76	$8.39	$9.07	$9.81
Unsmoothed Revenue requirement	$229.45	$238.93	$243.62	$248.14	$255.43

15.2 X factors for standard control services

The NTRM has also been used to generate the revenue X factors and a Smoothed Revenue trajectory for the 2014-19 regulatory control period. These quantities are shown in Table 15.2.

Table 15.2 - X factors and smoothed revenue for 2014-19 (ODRC) ($ million, nominal)

Year	2014/15	2015/16	2016/17	2017/18	2018/19
Unsmoothed Revenue requirement	$229.45	$238.93	$243.62	$248.14	$255.43
X factor	-50.59%	-15.00%	-1.00%	-1.00%	-1.00%
Smoothed Revenue requirement	$204.77	$241.41	$249.95	$258.80	$267.95

The annual revenue requirement (the 'Unsmoothed Revenue requirement') and the X factors are used to derive a Smoothed Revenue trajectory (the 'Smoothed Revenue requirement') in real terms over the 2014-19 regulatory control period.

15.3 Network Pricing Principles Statement and Pricing Proposal (Draft)

Power Networks submitted a draft of its Pricing Proposal and Pricing Principles Statement to the Commission as attachments to the Initial Regulatory Proposal.

15.3.1 Commission's Draft Determination

The Commission engaged consultant Deloitte to review Power Networks draft Pricing Principles and Pricing Proposals documents. The Commission accepted Power Networks' draft Pricing Proposal, with two exceptions:

- The proposed Excess kVAr charge, which the Commission considered was inconsistent with clauses 74(1)(a) and (1)(b) of the NT Network Access Code; and
- The conversion of the kVA demand charge for commercial customers to a capacity charge, which may not be consistent with the NT Network Access Code as it does not necessarily appropriately balance the interests of Power Networks and network users, or promote price stability.

15.3.2 Power Networks' revised proposal

Power Networks does not accept the Commission's decision in relation to the Excess kVAr tariff, for the reasons set out in section 4.

In relation to the use of a capacity tariff for commercial customers, Power Networks makes the following points:

- The relationship between kVA demand tariff and a kVA capacity tariff is simply that the customer is billed for the monthly maximum kVA in the case of the former, whereas with the latter the customer is billed for the peak demand in preceding months.
- A capacity tariff much more accurately and equitably reflects the costs of providing network services to a customer than a demand tariff. The network's costs are driven by the peak demand imposed on it. A customer that imposes one kVA of peak demand in summer only has the same impact on the network as a customer that imposes one kVA demand on the network every month. It is reasonable that both should receive the same network charge, although with a kVA demand charge the summer peaking customer receives a network charge that is a fraction of that of the customer with a constant demand.
- Because of this great degree of cost reflectivity, capacity tariffs are commonplace throughout the electrical industry. In New South Wales, South Australia and Victoria, capacity tariffs have been in place for many years. In Victoria and South Australia an agreed capacity is used, based upon historical consumption. In New South Wales, an automatic rolling 12 month reset is applied by Ausgrid.
- Capacity charges are also offered by the NEM Transmission Network Service Providers (TNSPs) as an option for the non-locational component of transmission charges, at high load factor locations.
- The capacity tariff will result in greater pricing stability for customers (as it is proposed to be reset on an annual basis) and, as it initially would be

designed to recover the same revenue as its kVA demand equivalent, would not over signal the cost imposed on the network.

Power Networks therefore does not consider the Commission’s concern in relation to the use of a kVA capacity charge is valid. However, Power Networks has now carried out an assessment of the pricing impact on customers and appreciates that the introduction of the tariff would require a transition period. In addition, as the billing arrangements and the communication of this arrangement to customers require development, Power Networks now proposes that the introduction of the capacity tariff may be deferred until the 2019-24 regulatory control period.

15.3.3 Power Networks Pricing Proposal

Power Networks’ Network Pricing Principles Statement and Pricing Proposal (Draft) is provided at Attachment 6, and the Pricing Proposal Model that supports this document at Confidential Attachment 15. This document will be modified, following the Commission’s Final Determination on network revenue for 2014/15, to become Power Networks’ Pricing Proposal.

This document sets out in detail Power Networks’:

- Principles and methods used for establishing the network tariffs to apply to Standard Control Services and Alternative Control Services;
- Proposed pricing strategy for the 2014-19 regulatory control period;
- Proposed indicative network prices for 2014/15;
- Information in support of the adoption of the Excess kVAr tariff, described in section 4; and
- An indication of the approach proposed to manage the price movements for large customers, in support of side constraints that apply to tariff classes.

This document also demonstrates the compliance of the 2014/15 network prices with the requirements of the Rules and the Code, and the final document submitted to the Commission will demonstrate compliance with the Commission’s 2014 Final Networks Price Determination. This section provides an overview of the proposed pricing for customer classes in 2014/15.

15.3.4 Prices for customer classes

Power Networks has classified its network tariffs into three tariff classes, as follows:

- Domestic;
- Commercial LV (all commercial customers connected to the Low Voltage network and Unmetered supplies); and
- Commercial HV (commercial customers connected to the High Voltage network).

The rationale for the formation of these customer classes is set out in the draft Pricing Proposal at Attachment 6.

In constructing the price paths for the customer classes, the following assumptions have been made. Note that these price changes are indicative only and the final percentage change might vary in Power Networks' final Pricing Proposal:

- The percentage price increase on all tariff components will be the same in 2014/15. In that year, rebalancing of tariffs will be postponed in order to avoid some customers experiencing increases in network prices higher than the initial price change;
- The Commercial HV tariff class is currently recovering less revenue than the cost of supply. The average price for customers within this tariff class will be increased annually by 1 per cent above the overall revenue trajectory from 2015-19 (a maximum 2 per cent side constraint on tariff class movement is set out in clause 6.18.6 of the Rules);
- The domestic tariff class is recovering more revenue than the cost of supply. It is proposed to decrease the price for this tariff class by 1.0 per cent per annum above the average price movement from 2015-19;
- There are three different customer tariffs within the Commercial LV tariff class: Commercial; Unmetered supplies; and Commercial kVA (with annual consumption greater than 750 MWh). In order to improve the alignment of these tariffs with their costs of supply, Commercial kVA will be increased by 1.0 per cent per annum. Unmetered supplies decreased by 3 per cent per annum, and Commercial increased by 0.7 per cent per annum.

Further detail on the price paths and the rationale for the price changes is contained in the draft Pricing Proposal. The rebalancing of tariffs is also proposed to take place from 2015-19, to further improve their cost reflectivity.

15.4 Customer impacts

The proposed increase in Network Tariffs is passed on to retailers in the first instance. Retailers can pass on the increased Network Tariffs to contracted customers if they have a pass-through clause in their contracts. However, for customers on pricing orders, retailers cannot charge above the regulated retail tariff.

Table 15.3 outlines the impacts of the proposed 2014/15 Network Tariff increase for each customer type, based on a sample of customers.

Table 15.3 - Customer Impacts

Tranche	Customer Type	2014/15	
		Average Increase	Increase Range
1-4	Medium to Large Contracted Customers	11%	6-14%
5-6	Residential and Small Commercial Pricing Order Customers	No Impact	

The price changes in Table 15.3 are indicative only, as the final 2014/15 Networks Pricing Proposal will be subject to the Commission's 2014 Networks Price Determination Final Determination. In addition, the impact on each contracted customer will depend on its individual consumption and demand profile.

Power Networks will submit its final 2014/15 Networks Pricing Proposal following the Commission's 2014 Networks Price Determination Final Determination in April 2014.

16 Pass through and contingent project arrangements

This section sets out Power Networks' proposals concerning pass through arrangements and contingent projects.

Pass through arrangements are established in section 71 of the Code and section 6.6.1(a) of the Rules. Their purpose is to permit the regulator to vary the revenue cap for nominated events that are material and beyond the control of the network.

Contingent projects are provided for under Rules clause 6.6A, where if the timing or scope of a material project is uncertain it can be accepted as a variation of the revenue cap by the regulator. If the project is triggered, the regulator reviews the expenditure and varies the revenue cap.

In the Framework and Approach paper, the Commission proposed the same pass through provisions as for the current regulatory control period, namely:

- Change in tax or insurance events;
- Force majeure events;
- Regulatory compliance events;
- Service standard events; or
- Such other events that satisfy the following requirements:
    - the occurrence was not anticipated at the time of the preceding determination or was, while allowable, explicitly excluded from affecting the outcome of that determination on the grounds that the likely impact on Power Networks was unknown or too difficult to quantify at the time, or
    - the occurrence is not a result of actions of Power and Water's board or management or of decisions of the Government in its capacity as owner or shareholder or guarantor of Power and Water.

The Commission proposed a cost pass through threshold of 1% of smoothed forecast revenue for cost pass through events (as has been adopted by the AER).

Power Networks sought the following changes and clarifications to the pass through events proposed by the Commission:

- Clarification of the manner in which the cost pass through threshold would apply to capital expenditures;
- A new technology event, if a mandated roll out of smart meters or smart grid technology; and
- An emissions trading scheme event, if costs are impacted by changes to emissions trading arrangements;

- Clarification that the insurance deductible component, in the event of an insurance claim, would be eligible as a pass through under the insurance event;
- Clarification that liability above the insurance cap, in the event of an insurance event, would be eligible as a pass through under the insurance event;
- A retailer insolvency event, as per clause 6.6.1(a1)(4) of the Rules; and
- A major network augmentation event.

16.1 Commission's Draft Determination

Pending legal clarification of the scope for authorising such arrangements through the network price determination, in its Draft Determination the Commission accepted the following as pass through events for Power Networks for the forthcoming regulatory control period:

- *the pass through events specified in the NER:*
  - *a regulatory change event;*
  - *a service standard event;*
  - *a tax change event; and*
  - *a terrorism event*
- *additional pass through events:*
  - *an insurance event;*
  - *a force majeure event; and*
  - *such other events that satisfy the following requirements: (i) the occurrence was not anticipated at the time of the network price determination was made, or were, while allowable, explicitly excluded from affecting the outcome of that determination on the grounds that the likely impact on PWC Networks was unknown or too difficult to quantify at the time, and (ii) the occurrence is not a result of actions of PWC's board or management or of decisions of the Territory Government in its capacity as owner or shareholder or guarantor of PWC.*

In the Draft Determination, the Commission did not clarify the operation of the materiality provision for expenditure of a capital nature[99].

[99] Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, p. 113.

In relation to the other events nominated, or where clarification was sought by Power Networks, the Commission confirmed the events set out in the Framework and Approach Decision and:

- Accepted that liability above an insurance cap and insurer credit risks fell within the category of an insurance event;
- Did not consider that the insurance deductible amount would fall within the category of an insurance event;
- Rejected a major network augmentation event. However, the Commission did consider such an event might be more appropriately the subject of a contingent project, as discussed below.

16.2 Power Networks' revised proposal

Power Networks accepts the Commission's decision not to clarify the application of the cost pass through events for expenditure of a capital nature, although it maintains that clarification would have been useful to reduce uncertainty over how the Commission would treat such an application.

Insurance deductible amount

Power Networks does not accept that an insurance deductible amount falls outside the insurance pass through provision. Insurance arrangements have the following basic parameters:

- The insurance cap, which limits the maximum payment in the event of a claim against the insurer; and
- The deductible amount, which also serves to limit the liability of the insurer and avoid the insured making small claims.

The two parameters taken together define the risk sharing arrangement between the insured and insurer.

In the event of a large claim, the insured would potentially meet the cost of the deductible and the cost of any amount above the cap. It is appropriate for both of these amounts to be treated as pass through items. Indeed, the AER has in the past approved pass through of the insurance deductible amount[100].

Retailer insolvency event

The Commission, in its Draft Determination, has not quoted the provisions from the most recent version 60 of the Rules[101]. In version 60, the glossary defines a pass through event as follows:

> ***pass through event***
>
> For a distribution determination - the events specified in clause 6.6.1(a1)

[100] In the case of Murraylink, on 29 August 2008.

[101] Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, p. 111.

6.6.1 Cost pass through

(a1) Any of the following is a *pass through event* for a distribution determination:

(1) a *regulatory change event*;

(2) a *service standard event*;

(3) a *tax change event*;

(4) a *retailer insolvency event*; and

(5) any other event specified in a distribution determination as a *pass through event* for the determination.

Power Networks therefore does not accept the Commission's rejection of a retailer insolvency pass through event. In the developing contestability arrangements in the Northern Territory, this could constitute a risk to Power Networks.

Regulatory change event

Cabinet has approved a package of reforms for the NT electricity market, including application of relevant parts of the NEL and NER for the economic regulation of distribution networks to be adopted by the Northern Territory from 1 July 2014[102].

However, much of the detail in terms of the requirements, timing and nature of the transitional arrangements over the next regulatory control period are currently unknown. Where the regulatory reform imposes significant costs on Power Networks, Power Networks will apply for a Regulatory Change cost pass through event.

Chapter 10 of the NER defines a regulatory change event as:

"A change in a regulatory obligation or requirement that:

(a) falls within no other category of pass through event; and

(b) occurs during the course of a regulatory control period; and

(c) substantially affects the manner in which the Transmission Network Service Provider provides prescribed transmission services or the Distribution Network Service Provider provides direct control services (as the case requires); and

(d) materially increases or materially decreases the costs of providing those services."

Power Networks seeks confirmation from the Commission that the extensive and labour intensive process of negotiating the transitional arrangements to apply,

102 David Tollner (NT Treasurer), *Letter from the Treasurer re NPD and application of NER*, November 2013.

including derogations to the NER, would be considered *"a change in a regulatory obligation or requirement"*.

Contingent projects

Power Networks welcomes the Commission's proposal to support the use of the Rules contingent project provisions. However, the materiality threshold in the Rules under clause 6.6A.1(b)(2)(iii) requires that the proposed contingent capital expenditure exceed the larger of $30 million or 5 per cent of the annual revenue requirement. This materiality threshold is inappropriately large for the scale of Power Networks' business, which is significantly less than the smallest NEM business, and the Commission's proposed threshold of $15 million is considered more appropriate[103].

Power Networks notes, however, that the Commission's advice is subject to legal confirmation that it has the power to approve a contingent project pursuant to the provisions of clause 71 of the NT Network Access Code, which permit the Commission to revoke or reset the revenue cap.

In the event that that the Commission's legal advice does not permit the Commission to approve a contingent project, Power Networks proposes that contingent projects should be included in the capital expenditure forecast. There are two projects which fall into this category, PRD30600 New Mitchell St Switching Station, and Stage 2 of PRD30309 Construct East Arm Zone Substation, as discussed in section 8.

16.3 Structural separation

As outlined in section 1.4, the Northern Territory Government recently announced the structural separation of Power and Water into the competitive and non-competitive businesses. The Generation and Electricity Retail business units will become separate stand-alone government-owned corporations (GOCs) from 1 July 2014, with the remaining 'monopoly' business units and residual functions retained by the Power and Water GOC.[104]

At this time, the details of the structural separation are still being developed. In particular, the longer term arrangements regarding shared services and corporate overheads are currently unknown. The initial arrangements from 1 July 2014 are that corporate services will remain in the Power and Water GOC with Power Networks, so the current corporate overheads and shared services won't change significantly in the short term.

If the structural separation of Power and Water results in the imposition of significant costs on Power Networks, Power Networks would seek to recover this through cost pass through arrangements.

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103 Utilities Commission, *2014-2019 Network Price Determination – Draft Determination*, p. 113.

104 David Tollner (NT Treasurer), *Media release: New PWC Electricity Retail and Generation Corporations*, 13 December 2013.

In its Framework and Approach Decision Paper, the Commission advised that *"a structural separation event would fall within the ambit of other allowable events if it reflects a decision by Government as policy maker to improve the operation of the Territory electricity supply market. A decision to structurally separate PWC by Government as shareholder for commercial reasons would be unlikely to qualify as a pass-through event."*[105]

Power and Water seeks clarification from the Commission that any expenditure above the cost pass through threshold as a consequence of the structural separation of Power and Water from 1 July 2014 could qualify as:

> *"such other events that satisfy the following requirements: (i) the occurrence was not anticipated at the time of the network price determination was made, or were, while allowable, explicitly excluded from affecting the outcome of that determination on the grounds that the likely impact on PWC Networks was unknown or too difficult to quantify at the time, and (ii) the occurrence is not a result of actions of PWC's board or management or of decisions of the Territory Government in its capacity as owner or shareholder or guarantor of PWC."*

Specifically, Power and Water would like clarification that the structural separation event has been explicitly excluded from affecting the outcome of the 2014 Networks Price Determination on the grounds that the likely impact on Power Networks was unknown or too difficult to quantify at the time.

[105] Utilities Commission, *2014-2019 Network Price Determination – Framework and Approach Decision Paper*, November 2012, p. 82.

17 Glossary and certification

17.1 Glossary

Term	Definition
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
CAM	Cost Allocation Method
Capex	Capital expenditure
Capital Contributed Works	Works for which the customer(s) contribute directly to the cost of providing the distribution assets (see also Customer contributions)
CBD	Central Business District
CIPS	Channel Island Power Station
Code	Northern Territory Electricity Networks (Third Party Access) Act Schedule – Electricity Networks (Third Party Access) Code
Commission	Utilities Commission, the Northern Territory electricity regulator
Contestability	Customer choice of electricity supplier
CPI	Consumer Price Index
CPM	Carbon Price Mechanism
Current regulatory control period	The regulatory period 1 July 2009 to 30 June 2014
Customer contributions	The value of any network augmentations or extensions funded directly by customers
DAE	Deloitte Access Economics Pty Ltd
Demand	Instantaneous power usage (kVA) at a point in time
Distribution network	The assets that link energy consumers to the transmission network
Distribution substation	A substation used for local supply, transforming power from high voltage of 22 or 11 kV to low voltage of 400/230 V
DM	Demand Management, techniques to modify customers' consumption patterns aimed at constraining demand at times of peak network demand
DNSP, Distributor, distribution business	Distribution Network Service Provider
DRP	Debt Risk Premium

Term	Definition
DSEP	Distribution System Extension Policy, a policy on charges for extension and connection to the network
FTE	Full-time employee
GDP	Gross Domestic Product (for Australia)
GOC Act	Northern Territory Government Owned Corporations Act, as in force at 1 February 2011.
GSL	Guaranteed Service Level
GSP	Gross State Product (for the Northern Territory)
Huegin	Huegin Consulting
HV, High Voltage	Equipment or supplies at voltages of 11 kV or above or the single phase equivalent (6.35 kV)
IBT, Inclining Block Tariff	A network tariff energy rate in which the rate increases as consumption increases
IRP	Initial Regulatory Proposal
IEEE	Institution of Electronic and Electrical Engineers (US)
kVA, MVA	Kilo-volt amps and Mega-volt amps, units of instantaneous total electrical power demand. See also Power Factor
kVAr, MVAr	Kilo-volt amps (reactive) and Mega-volt amps (reactive) units of instantaneous reactive electrical power demand. See also Power Factor
kW, MW	Kilo-watts and Mega-watts, units of instantaneous real electrical power demand. See also Power Factor
kWh, MWh, GWh	Kilo-watt hours, Mega-watt hours and Giga-watt hours, units of electrical energy consumption
Load duration	The time for which the load at a location exceeds a particular threshold
LRMC	Long Run Marginal Cost
LV, Low Voltage	Equipment or supply at a voltage of 230V single phase or 400V, three phase
MAR	Maximum Allowable Revenue
Marginal Cost	The cost of providing a small increment of service
MRP	Market Risk Premium
NEL	National Electricity Law - South Australia, National Electricity (South Australia) Act 1996 as at 1 February 2013
NEM	National Electricity Market
NER, Rules	National Electricity Rules
NPD	Network Pricing Determination
NPV	Net Present Value
NTRM	Northern Territory Revenue Model (the AER's PTRM adapted by the Utilities Commission for a pre-tax regulatory framework)
ODRC	Optimised Depreciated Replacement Cost, a method of asset valuation
Off-Ramp	A regulatory decision to re-open a regulatory determination

Term	Definition
Opex	Operating and maintenance expenditure
PB	Parsons Brinckerhoff
Power Factor	A measure of the ratio of real power to total power of a load. The relationship between real, reactive and total power is as follows: $PF = \frac{Real\ Power\ (in\ kW\ or\ MW)}{Total\ Power\ (in\ kVA\ or\ MVA)}$ $Total\ Power\ kVAr = \sqrt{Real\ Power\ kW^2 + Reactive\ Power\ kVAr^2}$
PoE	Probability of Exceedence
PTRM	Post Tax Revenue Model (developed by the AER in accordance with the Rules)
Proposal	Power Networks' Revised Regulatory Proposal
RAB	Regulatory asset base, Regulated asset base
RBA	Reserve Bank of Australia
RFM	Roll Forward Model for the RAB (developed by the AER in accordance with the Rules)
RIN	Regulatory Information Notice (issued by the Utilities Commission in April 2013)
RIT, RIT-T, RIT-D	Regulatory Investment Test, Regulatory Investment Test for Transmission, Regulatory Investment Test for Distribution
RRP	Revised Regulatory Proposal
Rules	National Electricity Rules
SAIDI	System Average Interruption Duration Index, a measure of the average duration of customer interruptions
SAIFI	System Average Interruption Frequency Index, a measure of the average frequency of customer interruptions
SCADA	Supervisory Control And Data Acquisition system
Side constraint	A limitation in the maximum price change which may be applied to a tariff component or a tariff class in any year
SKM	Sinclair Knight Merz
ESS Code	Electrical Standards of Service Code, published by the Utilities Commission
STPIS	The AER's Service Target Performance Incentive Scheme, established subject to the Rules
SWMD	Standard Weather Maximum Demand – an estimate of the demand occurring for average temperature conditions
TAB	Taxation Asset Base (required for Power Networks to implement the AER's PTRM)
ToU	Time of Use, a system of pricing where energy or demand charges are higher during peak periods

Term	Definition
Transmission Network	The assets that enable generators to transmit their electrical energy to zone substations
Unmetered supply	A connection to the distribution system which is not equipped with a meter
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
WIP	Work In Progress
Zone substation	A substation used to transform voltage from transmission voltages of 132 or 66 kV to high voltage of 22 or 11 kV

17.2 Certification Statement

CERTIFICATION OF REASONABLENESS OF KEY ASSUMPTIONS THAT UNDERLIE CAPITAL EXPENDITURE AND OPERATING AND MAINTENANCE EXPENDITURE FORECASTS

The Directors of the Power and Water Corporation, hereby certify the reasonableness of the changes to key assumptions between the Initial Regulatory Proposal and Revised Regulatory Proposal which:

(1) underlie:

(a) the proposed capital expenditure forecast as set out and included in PWC Networks' building block proposal; and

(b) the proposed operating and maintenance expenditure forecast as set out and included in PWC Networks' building block proposal; and

(2) are also set out and included in PWC Networks' building block proposal.

Signed: K C Clarke

....

KEN CLARKE dated the 24 day of January 2014

(Print name)

CHAIRPERSON

17.3 Managing Director's Statutory Declaration

THE NORTHERN TERRITORY OF AUSTRALIA

OATHS, AFFIDAVITS AND DECLARATIONS ACT

STATUTORY DECLARATION

I, JOHN LEONARD BASKERVILLE

U34, 14 Salonika Street, Parap NT 0820

(*name, address and occupation*)

do solemnly and sincerely declare as follows:

1. I am an officer, for the purposes of the *Corporations Act 2001*, of the Power and Water Corporation.
2. The Power and Water Corporation is a Northern Territory Government owned corporation established under the *Power and Water Corporation Act* whose shareholder is the Treasurer, as Shareholding Minister, and PWC Networks, the network business division of the Power and Water Corporation is the network provider who provides electricity network access services in the regulated electricity networks of the Northern Territory – Darwin-Katherine, Alice Springs and Tennant Creek -for the purpose of clause 65 of the *Electricity Networks (Third Party Access) Code* (**NT Access Code**);
3. The response of PWC Networks regarding the information that has been updated since the submission of the Initial Regulatory Proposal dated 16 September 2013, and required to be provided and to be prepared and maintained as specified in the Utilities Commission of the Northern Territory's (**Commission**) regulatory information notice (**Notice**) dated April 2013, is:

   (a) in accordance with the requirements of the Notice; and

   (b) is true and accurate, and in all material respects can be relied upon by the Commission to:

      (i) make the distribution determination to apply to PWC Networks for the 2014-15 to 2018-19 regulatory control period; and

      (ii) approve the pricing proposals to apply to PWC Networks.

   in respect of the regulated electricity distribution services PWC Networks provides in the regulated networks of the Northern Territory – Darwin-Katherine, Alice Springs and Tennant Creek.

This declaration is true and I know it is an offence to make a statutory declaration knowing it is false in a material particular.

Declared at Darwin

(place)

on the 28th day of January 2014

Baskerville

Signature

Before me,

(Justice, commissioner for declarations or authorised person)

Kelvin Strange
Commissioner for Oaths (NT) / Solicitor
(08) 89857211

2014 NETWORK PRICE DETERMINATION
REVISED REGULATORY PROPOSAL
1 JULY 2014 TO 30 JUNE 2019

JANUARY 2014

HEAD OFFICE

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