Response to IPP Issues Paper

3 March 2014

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Limited The National Grid

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EXECUTIVE SUMMARY

The Commission and its advisors have a significant task to assess and judge our RCP2 proposal in a comparatively short timeframe. To assist them, we provided a detailed and comprehensive submission in December supported by follow-up presentations and meetings with the Commission, customers and other stakeholders.

We are currently in a targeted 'Q & A' process with Commission staff and advisors to support their review. Our response to the Issues Paper continues this engagement and is directed at: keeping other stakeholders informed about the ongoing, more detailed 'bilateral' engagements; ensuring that the overall process takes previous consultations and information provided into account; and emphasising our desire to be given sufficient opportunity to address any concerns that the Commission may have before it makes its draft determination.[1]

Before discussing our response in detail, we wish to reiterate the importance of taking a holistic view of our proposal. We have used integrated forecasting and governance processes, given the interdependencies between Capex, Opex and service performance. Interdependencies include:

- trade-offs between Capex and Opex (e.g. our approach to data centres);
- improved staff and system capability facilitating savings in Grid-related expenditure; and
- improvement in asset management to achieve our challenging service performance targets.

Changes to any of these aspects in isolation or specifying more stringent performance targets may require other aspects of the proposal to be revised.

Evaluation of RCP2 Expenditure

Our RCP2 proposal was developed with the intent of supporting our aim of becoming a fully service-oriented business. Our expenditure is driven by genuine need and will deliver a valued, cost-effective service in RCP2.

To evaluate our proposal, stakeholders must have sufficient, accurate and timely information. In our response to the Issues Paper we have highlighted a number of issues that may inhibit their ability to reach fully informed views, in particular:

- unfavourable conclusions drawn about our asset management approach based on Capex variances in RCP1;
- clarification on how Opex variances should be assessed and interpreted;
- further information to assist in demonstrating how the benefits arising from our RCP1 initiatives have been taken into account in our expenditure proposals;
- how we meet an appropriate definition of good electricity industry practice (GEIP); and
- the basis for the 7.5% productivity adjustment applied to Grid and ICT Base Capex and the application of alternative efficiency targets to Grid Opex.

Service Performance Measures

We are proposing a set of new service performance measures for RCP2. These were developed through consultation with customers and the wider industry. The associated targets represent 'stretch-goals' for the period and are linked to a financial incentive mechanism.

[1] For example, if the Commission or its advisors consider that our forecasts are not sufficiently justified, we expect to be given the opportunity to respond directly through the formal Q&A Process.

As discussed above, these measures have been developed alongside our expenditure forecasts, and achieving them is predicated on our asset health targets, and on delivering our Capex and Opex plans.

In our submission, we address a number of issues raised by the Issues Paper, in particular:

- the risk of replicating a consultation process in which the Commission participated, and that we believe was thorough, effective and inclusive; and
- criticism that our proposal is relatively weak on customer service related measures compared to overseas jurisdictions.

Form of the Individual Price-Quality Path (IPP)

On the form of the next IPP and amendments to IMs (Input Methodologies), we are generally supportive of the Commission's approach and appreciate the ongoing constructive engagement.

In our submission, we address a number of issues raised by the Issues Paper, in particular that:

- changes to the Consumer Guarantees Act (CGA) are addressed so that we are not subject to "double jeopardy" (i.e. penalised twice under different regulatory regimes for the same loss of supply event);
- we are, by one means or another, compensated for the "expected" costs of providing the CGA indemnity;
- the IPP reset process supports effective incentive mechanisms by avoiding the pre-emptive removal of, as yet, unidentified efficiencies;
- large re-conductoring projects are included as Major Capex by expanding the relevant IM definition; and
- any change to cash flow timing assumptions for setting our forecast MAR be carefully assessed, with ample opportunity for consultation with stakeholders.

Conclusion

We aim to achieve our service performance targets while meeting our cost objectives: to reduce Base Capex and Grid Opex, and hold other costs flat in real terms through RCP2. These objectives have been developed holistically and are interdependent. Adjustments to any one aspect could require other aspects to be revised.

We have sought to ensure that our stakeholders can be confident that our forecast expenditure is both prudent and efficient. We are happy to provide further information and clarification on any aspect of our proposal to demonstrate this.

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1. INTRODUCTION

This document provides feedback to the Commerce Commission (Commission) and interested parties on the Issues Paper[2] published by the Commission.

1.1. Background

Our RCP2 expenditure proposal was submitted to the Commission on 2 December 2013. The proposal sets out our planned expenditure and service performance targets for the 2015 to 2020 period (RCP2). The Commission has published our main proposal document on its website. For interested parties, we have provided the full supporting document suite on our website[3].

1.1.1. Document Structure

This document is structured as follows.

- **Chapter 2** addresses our expenditure plans for RCP2 and how these should be evaluated.
- **Chapter 3** addresses our Grid output measures and incentive scheme.
- **Chapter 4** addresses the Commission's views on the form of the RCP2 price path.
- **Appendix A** sets out further background information for stakeholders including views on the successful operation of incentive-based regulation.
- **Appendix B** includes an index to our original submission.
- **Appendix C** contains specific responses to the questions set out in the Issues Paper.

Relevant paragraphs in the Issues Paper are referenced in the section heading. Questions not explicitly answered in the chapters are addressed in Appendix C.

1.2. Strategic Intent

Our RCP2 proposal reflects the following strategic intent:

- we should pursue the best value solutions for our customers and stakeholders, regardless of whether they involve our assets;
- we think and act as a services company – long term success is linked to reputation with customers and stakeholders;
- financial value is a long-term game – we seek a fair return from doing our job well;
- there is an enduring need for a resilient grid; and
- we will not compromise on safety.

[2] "*Invitation to have your say on Transpower's individual price-quality path and proposal for the next regulatory control period: Issues Paper*" dated 10 February 2014.

[3] Submission is available here.

This summary of our strategic intent was used to set the context for our proposal when briefing the Commission and other stakeholders[4].

Our proposal is underpinned by this strategic view, including our:

- open, straightforward engagement with customers, the Commission and other stakeholders on our expenditure plans;
- development of new service performance measures based on areas of our performance that are important to our customers;
- application of a 7.5% productivity adjustment[5] to our base Capex allowance and specific savings targets to Grid Opex;
- voluntary reduction in revenue arising from "scope reductions" under the Opex incentive mechanism; and
- sustained efforts to deliver improvements and pursue efficiencies when developing our expenditure plans.

4 A copy of the presentation material from these briefings is also available on our website here.

5 The adjustment was applied to the aggregate of ICT and Grid Capex (nominal).

2. EVALUATION OF RCP2 EXPENDITURE

2.1. Purpose

This chapter addresses points raised in **Chapters 4 and 5 of the Issues Paper**.

2.2. Introduction

It is important that stakeholders are provided with sufficient, accurate and timely information on which to judge our proposal. There are a number of inconsistencies and ambiguous statements in Chapter 5 that are unhelpful. The use of inconsistent timeframes and terminology when referring to RCP1 may also hinder the ability of stakeholders to assess historic performance.

2.3. Alternative Forecasting Approaches (Para 4.18)

The Commission has proposed (paragraph 4.18) to determine our expenditure unilaterally in a number of areas – if they are not satisfied that our proposed expenditure is prudent and efficient.

We do not consider this approach is appropriate. If the Commission or its advisors consider that our proposed expenditure is not sufficiently justified, we should be given the opportunity to respond directly through the formal Q & A[6] process prior to the Commission issuing its draft decision.

As set out in our original submission, we believe our proposed expenditure is prudent, driven by genuine needs and that it will deliver a valued, cost-effective service. To assure our expenditure plans are prudent, we have subjected our forecasts to a robust challenge processes.[7]

To deliver a valued, cost-effective service in RCP2 we aim to achieve our service performance targets while meeting the following cost objectives:

- a reduction in Base Capex of more than 10% compared to RCP1 - this outcome includes a top-down 'productivity adjustment' of 7.5% applied to our (nominal) Grid and ICT forecasts;
- a reduction in annual Grid Opex of 8% by the end of RCP2; and
- Corporate Opex being held flat through the period despite increased insurance costs and the need to improve processes and staff competency to achieve our Base Capex and Grid Opex savings.

2.4. Proposed Base Capex Allowance (Para 5.5 to 5.9)

We do not agree with the statement in the Issues Paper that we have “forecast a trend of decreased grid asset expenditure counterbalanced by increased expenditure in non-network assets” (see

6 The Commission has arranged a series of questions and answers sessions with relevant Transpower staff and has submitted a series of information requests.

7 The governance, challenge process and development of forecasts over time have been set out in detail through the Commission’s formal Q&A Process (specifically in response to Commission question Q004).

paragraph 5.6). In real terms, expenditure on Grid assets during RCP2 is higher than RCP1 while non-network Capex (Business Support and ICT Capex) is lower.[8]

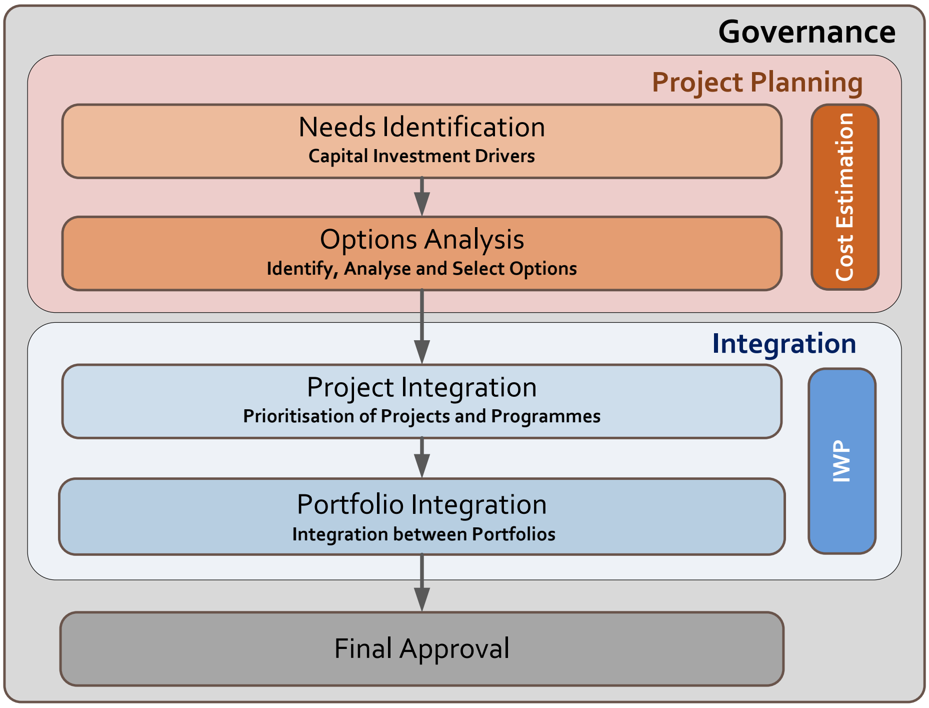
To assist in assessing expenditure comparability (paragraph 5.8), a comparison of historic E&D expenditure was provided (Figure 29 in MP01) that applies consistent definitions over time. It should also be noted that, contrary to the Issues Paper, there was expenditure on condition-driven conductor projects during RCP1.[9]

We are able to provide further information if required to clarify this point.

2.5. BASE CAPEX PERFORMANCE (PARA 5.10 TO 5.12)

The Commission appears to have drawn unfavourable conclusions regarding our asset management approach based on the variations in RCP1 expenditure versus plan. We believe this is inappropriate. The Commission's focus should be on whether changes to expenditure (timing or substitution) are the result of prudent asset management not simply that they occur.

Our Planning Lifecycle Strategy (AM03) explains our transmission system and asset planning approach. This planning process has been developed based on good practice guidance from internationally recognised sources, including PAS 55. The process identifies required Capex projects[10] and integrates these into an efficient and deliverable work plan across a rolling 10-year time horizon, as summarised in the following diagram.



The ability to substitute expenditure, in time and between categories, is a key feature of the IPP. During RCP1, we have continually reprioritised and rescheduled expenditure. Substitutions reflect many factors including: changing circumstances on the Grid; our developing service performance targets; and our increased understanding of asset health and criticality. As our approach to asset

8 For example, proposed Business Support Capex reduces from an annual average of $9.7m in RCP1 to $6.7m during RCP2. ICT Capex reduces from an annual average of $51.6m in RCP1 to $42m during RCP2.

9 Expenditure was incurred on Woodville-Mangamaire-Masterton and Wanganui-Stratford during the 2010/11 to 2014/15 period (see RT06).

10 While this process primarily addresses Capex, it also includes the planning of some maintenance projects.

risk management matures, we anticipate further change in priorities. We see this as a positive, rather than a negative, outcome.

The internal governance of capital expenditure is transparent and, follows good practice. Our Capital Governance Team (GCT), consisting of the CEO and relevant General Managers, meets on a monthly basis to continually assess capital expenditure priorities and trade-offs and monitor project delivery.

A prudent approach to asset management requires that we take into account the above factors and amend our expenditure plans accordingly.

Where a material change in strategy is agreed by the CGT, for example, a revision to the fleet strategy for outdoor to indoor switchyard conversions, this is submitted to the Transpower Board for approval.

The Commission has not signalled that it is uncomfortable with our governance approach and has not sought further information on our substitution decisions during the Q&A Process but we are able to provide further information as required.

2.6. RCP1 Initiatives (Para 5.13 to 5.14)

The Issues Paper states the Commission has been unable to identify the extent to which the benefits arising from RCP1 initiatives have been taken into account in our expenditure proposals.

MP01 lists benefits arising from the completed milestones. The relevant table in MP01 refers to completed milestones and not necessarily complete initiatives, as implied in paragraph 5.13. A number of initiatives (e.g., asset health indices) will continue to be developed during the remainder of RCP1 and into RCP2. We will complete the remaining initiative milestones in RCP1 and expect to see further benefits arising from these during RCP2.

Improvements that have been taken into consideration when establishing the RCP2 forecasts include:[11]

- improved safety processes and management systems;
- service performance targets based on the expectations of our customers;
- an internationally recognised approach to the identification, assessment and management of asset risk;
- asset criticality and health frameworks; and
- strong line of sight from our strategic plan to our asset management activities.

In addition, the initiatives have informed our asset management document suite. In particular the Planning Lifecycle (AM03), fleet strategies, and the asset health and criticality framework documents (BR02 and BR03) illustrate the impact of the initiatives on our forecasting approach.

We have also developed an Asset Management Framework which aligns our corporate objectives and day to day activities. This includes: an Asset Management Policy; Asset Management Strategy; Lifecycle Strategies; and Fleet Strategies (refer to MP01). This framework is aligned to good asset management practice including PAS 55.

To address the Commission's concern more specifically, we set out below more detailed information on the initiative benefits included in our RCP2 forecasts:

- **Asset Management Information System:** We have replaced our maintenance management system with Maximo. This will enable improvements to the specification and delivery of our maintenance activities. Key benefits include: improved reliability management; fewer

[11] Refer Section 4.2.1 of MP01.

unplanned works; enhanced service provider efficiency; reduced overhead costs associated with health and safety reporting; reduced stock holding costs; and reduced depreciation of in-stock items. The business case for Maximo stated that for stage 1 a $22m NPV over 10 years will be achieved. Benefits will begin to accrue in 2014/15.

- **Grid Operating Centres:** we have strengthened our focus on service delivery by further integrating our maintenance and operations activities through insourcing and consolidating our operational control function. The financial benefit of this is a $19.3 savings over RCP2 (see RT07). Non-financial benefits include: reduced operational risk; improved service performance; improved stakeholder satisfaction; and a more proactive approach to asset management, with direct ownership by controllers.
- **Asset Health and Criticality:** we have established asset health indices and a criticality framework to enhance our asset management decision making. Asset health and asset criticality have been used to assign risk estimates to our assets. Through this approach, we have been able to optimise the timing of asset interventions, and inform our investment decisions (optimisation of replacement and refurbishment spend) for transmission lines, transformers, and circuit breakers.
- **Service Provider Management**. We established new commercial agreements with our maintenance service providers in 2012. These ensure a more collaborative relationship with a shared goal of improving service to our customers and stakeholders. Benefits include: maintaining pricing at 2010 levels; no service provider is allocated more than 50% of Grid maintenance and project services contract work; an increased contractor resource pool, so that our workload requirements can be met in the medium to long term; and improved risk management across the value-chain.

2.7. Good Electricity Industry Practice (Para 5.15 to 5.19)

We agree with the concept of Good Electricity Industry Practice (GEIP) to assess the efficiency of our replacement and refurbishment Capex. It does require an appropriate definition for GEIP and it is unclear what definition the Commission proposes to use.

Paragraph 5.15 could be interpreted to mean that GEIP requires a fully quantified risk management approach and that GEIP asset management (and by association efficiency) can only be achieved with a fully quantified, financial risk model. We disagree with this.

In our view, the comprehensive application of such models is better described as ‘best’ or ‘leading’ industry practice and not the norm within New Zealand utilities. An inference that such models are a necessary condition for meeting GEIP is unhelpful for stakeholders assessing our expenditure plans.[12]

Use of a broader GEIP definition (such as in paragraph 4.3) is a better approach than identifying a particular commercial software platform (see paragraph 5.15) as a benchmark for good practice.

In paragraph 5.17 the Commission queries the extent to which “historical approaches” were used. Our entire Grid Capex proposal has been informed and influenced by our improved asset management approach. The degree to which certain improvements (e.g., asset health and sensitivity analysis) were directly applied varied with the significance of the portfolio and level of expenditure (refer below). Our wider forecasting approach and challenge processes[13] have ensured

[12] Our development of a basic risk framework focussing on asset health and criticality is a measured step in a staged improvement approach. We envisage the future development and application of numerical risk models (equivalent to CBRM) for the more critical asset fleets. However, this will require considerable further investment to develop.

[13] These processes and the resulting adjustments to planned expenditure have been set out in detail in response to the Commission’s requests for additional information (specifically in Q004).

that our proposed expenditure is consistent with our asset management objectives and is prudent and efficient.

Asset Health and criticality models have been used to optimise capital spend for the critical network assets: transmission lines, transformers and circuit breakers. We are currently developing models for less critical assets and, as part of our submission (refer to AM03 and AP02) we have outlined the future improvement path for our asset decision making processes.

Our objective is to have a fully quantified risk management approach operating before the end of RCP2. There is a dependency on the necessary reliability engineering building blocks, for example: asset health and criticality; and probability of failure statistics, loss and consequence weightings.[14] These are required for the application of any commercial model[15].

Our maintenance approach already applies a robust improvement programme that will achieve an appropriate approach to risk modelling[16] and expenditure optimisation, as described in AP02.

Our improvement approach aligns with the recommendations of the staged approach in the AMCL Maintenance Study; namely maintenance practice stabilisation, implementation of reliability engineering, and thirdly a numerical approach to maintenance cost-risk optimisation. The building blocks developed within maintenance cost-risk optimisation will ultimately be applied to detailed modelling of the Opex/Capex trade-off and hence optimised investment.

As a final point, we agree with the statement in paragraph 4.2 that "the assessment of forecast expenditure is not a mechanistic process and necessarily involves the exercise of judgement". We believe this is consistent with our use of outputs from the asset health and criticality models and our challenge round process, when RCP2 forecasts were assessed by the Transpower Board, CEO, and general management team.

2.8. Productivity Adjustment for Base Capex (Para 5.20)

The Commission has sought views from stakeholders on our proposed productivity adjustment. The adjustment is based on historic precedent for factors (listed in the Issues Paper) that will again be applicable to our Grid and ICT Capex during RCP2.

As discussed in MP01, the impact of these factors on productivity is not precisely quantifiable. Our estimate of 7.5% is at an aggregate level recognising the flexibility to reprioritise expenditure across portfolios (substitution) under the IPP. The estimate took into account:

- historical expenditure trends, including during RCP1;
- an appropriate level of incentive to drive internal productivity improvements;
- judgement by senior management on the level of achievable improvement;
- discussions with relevant portfolio owners and project managers; and
- projected Capex savings due to Opex initiatives (e.g. the move to hosted data centres).

14 We have met with Commission staff on a regular basis during RCP1 to set out the approach and status of the business improvement initiatives being undertaken including the improvements we are making to our asset management approach.

15 The application of a commercial model (such as EA Technology CBRM) is greatly simplified where there is an embedded approach to reliability engineering, such as a mature RCM programme.

16 The AMCL Maintenance Study made the following observation "Cost-risk optimisation of maintenance and inspection intervals is generally considered 'leading edge' practice currently. A number of organisations did not consider cost-risk optimisation in their maintenance requirements analysis process, an equivalent number was starting to consider it or planning to consider it in the future but only one was actively applying cost-risk optimisation in an effective manner".

The assessment and approval of forecast expenditure is not a mechanistic process but involves judgement supported by specialist knowledge. Our Board, CEO, senior management team and portfolio owners collectively concluded that a 7.5% reduction was both reasonable and achievable and that it would provide an appropriate incentive and target for productivity improvements during RCP2.

2.9. PROPOSED OPEX (PARA 5.21 TO 5.31)

We would be concerned if the Commission were to question the reliability of our forecasts simply based on observed re-prioritisation and substitution between portfolios. Instead the prudency or otherwise of those changes must be considered.

For RCP1 maintenance projects we have provided analysis (see MP01) explaining expenditure reductions during RCP1. The lower expenditure was driven in part by delivery constraints, deferrals and resource reprioritisation. Accordingly, we have excluded the effect of "reduced scope" from the IRIS mechanism, which results in a voluntary reduction in RCP2 revenue.[17] Our approach reflects: the underlying cause of the reductions (reduction of scope rather than gains in efficiency); our strategic approach (see Section 1.2); and our view on how IPP incentives should work (see Appendix A).

There are clarifications required to this section of the Issues Paper.

- The $29m figure for Opex below the RCP1 allowance referred to in the Issues Paper includes the self-insurance provision for the period. A more appropriate figure for assessing the extent of spend below the allowance is our forecast of $18m (refer page 29 of MP01).
- The phrase "non-network" in relation to ICT Opex may be confusing. A large proportion of ICT Opex directly supports the Grid assets but appears to be included in the assessment of a "non-network" overspend, referenced in paragraph 5.26.
- ICT Opex has increased through RCP1 as a result of completion of the primary TransGo routes and necessary investments in security and systems to align ourselves with international good practice. This has driven a number of improvements in the business including access and interrogation of grid information, improvements in land owner relationship management, and time series and remote access technologies. Through RCP2 we are holding ICT Opex effectively constant with small increases in data centre cost as a result of moving to an outsourced service model.
- Routine maintenance expenditure in both AC Stations and Transmission Lines will reduce (in real terms) over RCP2. There is no deliberate 'shift' in expenditure from AC Stations as the Commission suggests may be occurring. Trends are complicated by some re-categorisation of AC Stations maintenance projects to routine maintenance leading to the reduction in Figure 5.4.[18] We would be happy to elaborate further if necessary to address the Commission's uncertainty in this area.

2.10. OPEX PRODUCTIVITY (PARA 5.32)

The Commission is interested in our approach to Opex productivity and its relationship with Capex.

As part of our proposal, we identified significant savings in Grid Opex over the RCP2 period and have quantified savings in routine maintenance as a direct result of our capital expenditure programme:

[17] This is discussed in Section 4.4.5 of MP01.

[18] Please see discussion in AP02.

- $11.4m of savings as a result of divestments and our capital investment programme, including transformer replacements and outdoor to indoor conversions. Our Maintenance Activity and Cost Model (MACM) allow direct mapping from Capital projects and divestments to changes to routine maintenance expenditure (see APO2, RTO7 & MP01 – Chapter 7).
- $27.5m of targeted savings from improvements identified in our Maintenance Efficiency Study. Corrective maintenance transactions over a three-year period were analysed to identify low-performing facilities and estimate savings targets for corrective spend across each asset class by the end of RCP2. The savings were applied as incremental annual percentage improvements in performance (see APO2, RTO7 & MP01 – Chapter 7).

For Total Grid Opex, there is a reduction of 8% in real terms, from an annual spend of $102m to $94m (see MP01 – Chapter 7).

We considered a 'top-down' productivity adjustment (similar to that used for Capex) for Grid maintenance but felt the approach of specific saving targets (referred to above) was more robust in this case. In practice, maintenance savings will be realised through a combination of factors (improved planning, disciplined work management, as well as better asset performance).

Productivity across the remaining Opex categories, including Departmental and ICT, was also considered. However, applying an overall reduction was not considered appropriate for the reasons described in the Issues Paper. There is an on-going focus on improving efficiency and productivity. Examples include:

- organisational changes to insource and then optimise the costs of Grid Operating Centres leading to a saving of $19.3m during RCP2;
- approximately $4m savings from insourcing SCADA Model Maintenance over RCP2;
- during RCP1 we negotiated significant savings to telecoms (TransGo) support and maintenance costs through renegotiation with our service provider;
- similarly we have negotiated savings in support costs for security services despite forecast increases (through RCP2) in the number of security devices (see Q & A response 32 for details); and
- specific initiatives to reduce travel costs in RCP1 and others that will look at accommodation and motor vehicle costs.

3. SERVICE PERFORMANCE MEASURES

3.1. PURPOSE

This chapter provides further context on the RCP2 service performance measures,[19] addresses and clarifies points raised in **Chapters 6 of the Issues Paper**.

3.2. CUSTOMER CONSULTATION (PARA 6.7 AND 6.8)

The Commission includes five questions[20] related to the effectiveness of our consultation process with our customers.

We are surprised by this retrospective attention to a process in which the Commission participated. It has not raised concerns on the approach or the outcomes of the process.

Customer consultation was central to our process, appropriately thorough and inclusive.

Overview of Consultation

We summarise our consultation process below.

- An initial proposal was tested with customers in October 2012
- These were three subsequent consultation rounds during 2013 (March, July and September).
- The process included meetings and teleconferences to discuss customer feedback.
- These processes were supplemented by correspondence with industry on particular issues.
- During this process we received 23 public[21] submissions from 17 organisations.

The table below lists the consultation material, all of which is available on our website.[22]

Table 1: Service Performance Measures – Consultation Documents

Document	Publication Date
Customer-facing performance measures consultation	October 2012
Presentation and questionnaire	October 2012
Spread sheet of customer categories	October 2012
Revised proposal	March 2013
Summary of feedback and response	March 2013
Spread sheet of customer categories and targets	March 2013
Summary of feedback (March 2013 consultation)	July 2013
Presentation on availability measures and incentive regime	July 2013

19 We use the term 'Service Performance Measures' to refer to the set of measures and targets included in our RCP2 proposal. The associated term in the Capex IM is 'Grid Output Measures'.

20 These are Q21 through Q25.

21 Further submissions were received from individual customers on site (GXP) specific issues.

22 Link to consultation documents.

Summary of feedback (July 2013 consultation)	September 2013
HVAC Update	September 2013

Further discussion on how customer feedback was incorporated into our process and the measures themselves is set out in the remainder of this chapter and the responses contained in Appendix C.

3.3. PROPOSED MEASURES (PARA 6.9 TO 6.11)

The Commission has raised a question (Q25) as to whether the criteria used to determine POS[23] reflect feedback from stakeholders.

We consulted with stakeholders on this issue receiving views on impacts of interruptions at their POS. We also provided customers with details of how their POS was categorised and invited them to provide additional or updated information that might inform our approach. A number of POS categorisations were amended based on feedback.

The Commission has raised questions over the choice of HVAC circuits (Q26/27) included in our Asset Performance Measures (AP2).

We consulted on this matter over a number of months in 2013. We first discussed this issue with stakeholders in March 2013 and in July asked "Have we selected the right circuits for AP2?" We received helpful and considered feedback which was summarised in our September paper as follows.

> *Some customers suggested that we should consider including other circuits where system losses significantly increase when certain circuits are out of service. For example, when one or both of the PAK-WKM circuits are out of service, losses between WKM and OTA can increase markedly.*
>
> *We had originally concentrated on circuits which, when they are out of service, have the greatest potential to cause constraints. Since our July discussions with customers we have looked more closely at the impacts that taking circuits out of service has on losses.*
>
> *We undertook a load flow contingency analysis to assess changes in losses when certain circuits are out of service. The circuits whose outage has the greatest effect on system loss increase are those that supply the major load centres in the upper North Island and upper South Island.*

As a result of feedback we included an additional set of HVAC circuits to our AP2 availability measure. We also provided further information on particular circuits and sought further feedback on the Wairakei Ring, as follows.

> *Comments about the inclusion of specific circuits*
>
> - *With the new WRK-WKM C line upgrade Transpower could take out the existing WRK-THI-WKM circuits.*
> - *ATI-OHK could be included (along with the other Wairakei Ring circuits, unavailability of this circuit can cause constraints in the ring.)*
> - *RPO-WRK/BPE-TNG could be included (these outages have much the same effect as a RPO-TNG outage.)*
> - *Transpower could add BPE-BRK 1 and 2 circuits, they are critical for Taranaki generation export in dry years.*

[23] Refers to Point of Service.

- *In the Lower South Island NSY-ROX limits export.*
- *Other 110 kV circuits could also be considered for the list. Lack of 110 kV circuit capacity could further constrain 220 kV transfer.*

One area for which we welcome feedback is the Wairakei Ring following the commissioning of the WRK-WKM C line and the new generation projects. We have little constraint history so it would be useful to understand customer views on what future constraints might look like on an annual basis.

These are representative examples of our interactions with stakeholders from an open, co-operative and detailed consultation process.

We are confident that the consultation process was effective, included an appropriate level of engagement with stakeholders, and that we have adequately incorporated their feedback into our Service Performance Measures.

3.4. "Customer Service" Measures (Para 6.12 to 6.13)

The Commission states (paragraph 6.13) that, compared to overseas jurisdictions, our "proposal is relatively weak on the customer service related measures". We assume that this refers to our proposed Other Measures. We make the following comments.

1. The Other Measures were included in the consultation process. It became evident that availability and interruption measures were of more value to our customers and we have included these two as revenue linked measures in our proposal.
2. A comparison with overseas jurisdictions (the UK is referenced as an example) is likely to include regulatory regimes with more developed incentive regimes and customer-service mechanisms. Our proposed Other Measures represent a first implementation of such a regime in New Zealand which will mature over time.
3. We currently use annual customer satisfaction surveys[24] and more direct means (e.g. feedback via dedicated account managers) to ascertain levels of customer satisfaction.

3.5. Performance Incentive Regime (Para 6.14 to 6.23)

The Commission includes some high-level analysis of the proposed performance incentive regime[25] and a number of questions, which we respond to in Appendix C. Below we include some general points and clarifications.

The majority of issues in the Issues Paper raised were examined as part of our consultation process.

The following points should be clarified.

- The amount of revenue will be impacted by both number of incidents and circuit availability. Paragraph 6.17 implies that it is only impacted by the incentive rate for incidents.
- The statement (paragraph 6.18) "The incentive rate is the amount of revenue Transpower may receive or be penalised for as a result of an incident". To clarify, our proposed incentive rate is the penalty (reward) per incident in the range between the target and cap (collar).

[24] These cover overall performance, responsiveness, and our performance as individuals when dealing with customers. They provide feedback on how we can improve our service. Our current satisfaction target is above 80%.

[25] The Commission used terminology from the Capex IM (i.e. grid output adjustment). In seeking to remain consistent with our proposal we use the term performance incentive regime.

- In relation to paragraph 6.20, the VOLL related calculations were solely intended as a rough 'sanity check'. Caution should be used when attributing interruption costs.

3.6. COST OF INDEMNITIES UNDER THE CGA (PARA 6.24 TO 6.27)

This issue is addressed in our discussion of IPP modifications. Please see Section 4.7.1.

4. FORM OF THE PRICE QUALITY PATH

4.1. Purpose

This chapter responds to the Commission's proposed updates to the RCP2 price-quality path. It addresses **Chapters 3 of the Issues Paper**.

4.2. Introduction

Last year we proposed a number of amendments to the Part 4 regulations applicable to Transpower; several of these are discussed in the Issues Paper. The Issues Paper also introduces a number of other possible changes, most of which have been well signalled in advance. In this chapter we provide some background on our proposal and comments on the Commission's initial thoughts. We also provide initial comments on the Commission's proposed changes.

4.3. Use of Building Blocks Approach for RCP2

We agree that the building blocks approach should be retained. Our revenue forecasting systems are designed around this approach and our customers and other stakeholders are increasingly familiar with how it operates in practice.

We note that the Commission will consult separately on possible modifications to some of the building blocks. This will include proposals we have made to:

- remove non-GAAP depreciation rules that currently add complexity to revenue forecasting
- shift to an expenditure-based allowance for base Capex so that there is a more direct link between our allowances (and associated incentive mechanisms) and the way in which we operate and govern our business
- remove the non-GAAP regulatory cap on "interest during construction" costs that causes Transpower to under-recover project financing costs.

We understand that these issues will be addressed in the first half of this year.

4.4. Use of revenue wash-ups and an economic value account

We agree that the use of revenue wash-ups and economic value (EV) accounts should continue, and that we should continue the process of clearing historic EV account balances by the end of RCP2.

During RCP1 the revenue wash-up process produced some significant movements in forecast revenue. For example, of the $93.3 million movement in HVAC revenue from 2013/14 to 2014/15, $37.6m was due to the effect of wash-ups. This is not desirable in terms of price-path predictability, but we expect that wash-ups should become less significant as our capital programme scales down and involves fewer large commissioning events. We also welcome the Commission's consideration of a mechanism for spreading large wash-ups should they occur in future. We discuss this further in section 4.7.5.

4.5. SETTING THE FORECAST MAR ON AN ANNUAL BASIS

We agree that it is not necessary to translate our annual forecast MAR into a smoothed price path. We are forecasting a relatively smooth price path over RCP2 in any event. In general, end consumers are more likely to experience volatility in their prices due to changes in demand than due to the shape of our revenue path. This is because our fixed revenue allowance is allocated using a methodology that apportions charges annually based on various measures of demand.

For completeness, we have reproduced forecasts of our key charging rates below. A more complete analysis of our forecast revenue is available on our website[26].

Figure 1: Forecast interconnection rate

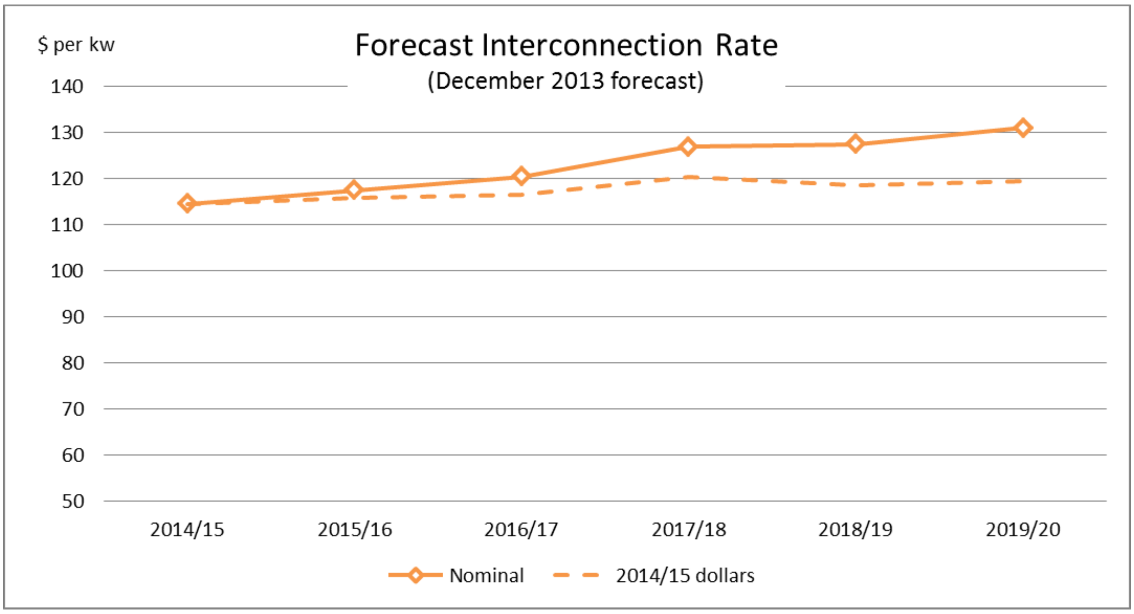
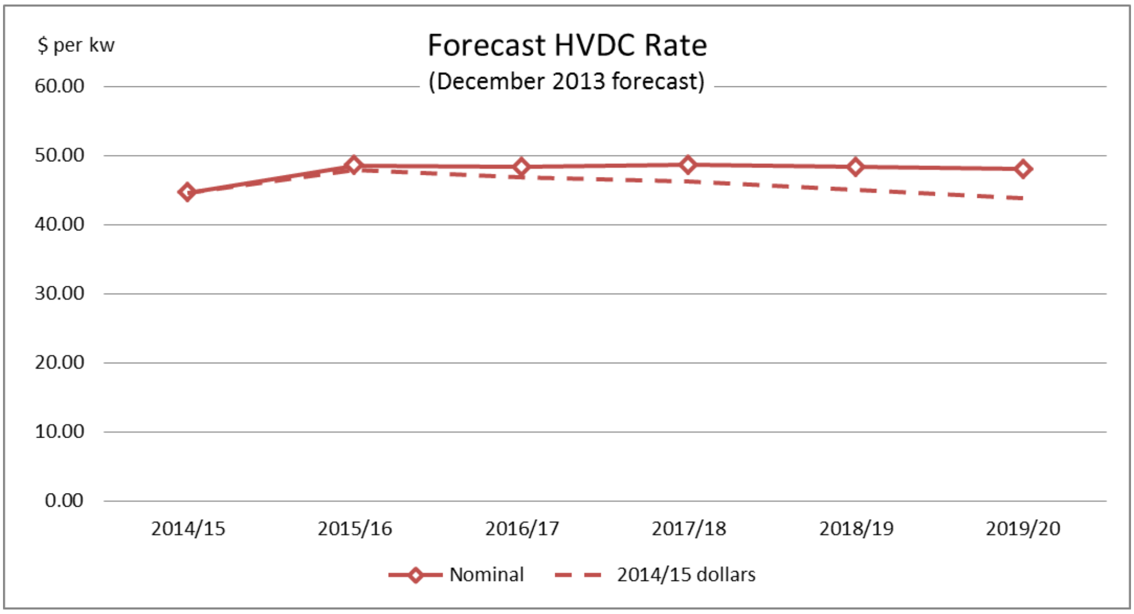


Figure 2: Forecast HVDC rate



[26] https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/rcp2-revenue-initial-forecast-information.pdf

4.6. Specific mechanisms to strengthen incentives to improve performance

We welcome the introduction of stronger incentives in RCP2. We consider it appropriate that such incentive mechanisms become the primary regulatory tool for seeking efficiency gains.

As discussed in Appendix A, it will be important that the reset process supports the effectiveness of incentive mechanisms by avoiding the pre-emptive removal of as yet unidentified efficiencies.

4.7. Modifications to the IPP

In the sections below we comment on the refinements that the Commission is considering for RCP2. In many cases these were prompted by requests that we have made and that may not be familiar to other interested parties. As such, we have taken the opportunity to briefly summarise our rationale for the changes we have proposed.

4.7.1. Allowances for contingent expenditure

We have asked the Commission to amend the IMs and IPP to address potentially material uncertainty in a small number of Opex and Capex categories. As an alternative to the options we put forward, the Commission is considering whether to create a new 'contingent' category for expenditure that is added to the IPP if pre-defined trigger conditions occur during the period. The Commission considers that this mechanism could be used for:

- large re-conducting projects;
- costs of meeting new indemnity provisions under the Consumer Guarantees Act (CGA);[27] and
- baseline demand response activities.

We do not consider that a contingent expenditure mechanism would provide the best solution at this stage. However depending on its design a contingent expenditure mechanism could provide a valid way of addressing the cost uncertainties above.

In the following paragraphs, we explain the rationale for the treatments we had originally proposed for these expenditure types.

Large Re-conductoring Projects

The Capex IM sets up two classes of grid capital expenditure:

- Base Capex is approved on a portfolio basis at the beginning of each control period. It covers 'non-major' Capex – primarily refurbishment projects, and small enhancement projects. Substitution is permitted within the portfolio, and the overall portfolio is subject to an accounting-based incentive mechanism (i.e. the mechanism operates by simply comparing approved and actual commissioning values each year); and
- Major Capex is approved on an individual project basis, and at any time. It covers large (>$20m) enhancement projects and expenditure is linked to specific, identified outputs. Projects are subject to judgement-based incentive mechanisms (i.e. the mechanisms operate through regulatory approval processes). Projects are approved based on assessed market benefits, and allowances include contingencies for scope and cost uncertainty.

[27] The Issues Paper discusses CGA indemnity from paragraph 6.24, where treatment as a 'pass through' or as an Opex category is discussed. Paragraph 5.38 seems to suggest treatment as contingent expenditure. Our proposal is treatment as a 'recoverable' cost with suitably designed recovery rules. For convenience, we include discussion of the CGA indemnity in this section.

In preparing our RCP2 proposal we identified a six large (>$20m) re-conductoring projects that do not fit comfortably within the Base Capex framework because:

- they are small in number and high in value relative to the balance of the Base Capex portfolio. As such, differences between forecast and actual costs or timing would materially alter annual Base Capex incentive adjustments.
- exacerbating this, re-conductoring projects have high scope, cost and timing uncertainty.

This poor fit reflects that the Base Capex framework is designed to deal with 'routine' expenditure, which is not how we would characterise these large re-conductoring projects. However, the projects do not automatically fit within the major Capex framework because the investment need is driven by asset condition rather than network usage.

Given these dual characteristics, we proposed that large re-conductoring projects are able to be approved through the Major Capex framework. As a result the projects would be:

- subject to a public consultation process on project need, options and cost. This is appropriate given the high cost of the projects, but should not be onerous given the need case and options analysis for condition-driven replacements is simpler than for demand-driven enhancements
- approved on 'maximum' cost basis, with Transpower able to recover the lesser of actual cost of the maximum approved cost (MAC). This is appropriate given the inherent cost uncertainty of re-conductoring projects, and their high cost relative to the annual Base Capex allowance. The same features make the Base Capex incentive settings (where Transpower retains or forfeits one-third of the value of any under- or over-spend respectively) a poor fit.

Classifying these projects as Major Capex could be achieved by expanding the definition of 'major Capex' in the Capex IM to include any re-conductoring project.

While a contingent project approach may be possible, it would need to replicate many of the existing Major Capex provisions in the Capex IM. Care would also need to be taken not to 'import' concepts, while relevant elsewhere, are not valid in this context.

Consumer Guarantees Act

The Consumer Guarantees Act (**CGA**) was amended recently such that Transpower indemnifies retailers for payments they make to their customers to remedy breaches of an 'acceptable quality guarantee' set out in the Act. The indemnity applies if the event giving rise to the breach arose on our network. The amendment will come into effect on 17 June 2014.

The statutory indemnity creates a new and difficult to quantify commercial risk for Transpower. In particular:

- we are unable to reliably forecast our exposure, as there is no suitable evidence base. This is because there is no comprehensive public information on CGA claims, and even if there were historic information we cannot be certain that payments will not increase once an indemnity is in place (i.e. the indemnity may have a 'moral hazard' effect)
- the indemnity is, as far as we can ascertain, unique to New Zealand. Several other jurisdictions have 'guaranteed service level' regimes, but these apply to distributors only and use fixed compensation schedules rather than open-ended remedy payments. Australian consumer law was recently amended to include an indemnity regime, but it differs materially from the New Zealand indemnity and does not provide guidance on our exposure
- it is conceivable that our exposure from indemnity payments will be large enough to have a material impact on our revenues. This is because remedy costs are essentially unbounded and there is limit precedent on what, in practice, would constitute a breach of the acceptable quality guarantee

- we are unable to purchase effective insurance for this risk[28]. This is unsurprising given that underwriters face the same challenge in quantifying our exposure.

In addition to these commercial concerns, we are also concerned that there is no integration between the indemnity and our IPP regulation. Ideally, we would reflect our experience of the indemnity into our Capex and Opex plans and into the design of the grid output incentive scheme. We consider that achieving this goal will require experience from at least one regulatory cycle with the indemnity in place.

Given these circumstances, we have proposed that indemnity payments should be treated as a recoverable cost for RCP2. The 'recoverable cost' category should allow recovery rules to be designed that allow efficient risk management during RCP2, while ensure that the policy objectives of the indemnity are not undermined.

The alternative is an additional "self-insurance" allowance – acknowledging the uncertainties that this entails.

Demand Response

During RCP1 we have advanced our ability to procure cost effective demand response (**DR**) for use as a transmission alternative. This involved a programme which included successful development of a technology platform, organisational capability, commercial arrangements and an understanding of the achievable price points for DR response products.

The DR program to date has shown that, as well as being potentially economic for deferring major Capex projects, DR may also be economic for deferring Base Capex projects and perhaps for other operational purposes.

We intend to continue to enhance and develop our DR capability during the rest of RCP1 using the approved GUP funding, but expect to exhaust that funding at around the time RCP2 starts.

In our view, the key objective is ensuring the regulatory mechanisms permit and encourage Transpower to economically develop and utilise cost effective DR. Funding approaches for baseline DR activities and potential transactional uses are discussed below.

Baseline DR: the enhancement and development of DR capability

The work we are undertaking in RCP1, and hope to continue in RCP2, is to develop DR capability in regions outside of the upper North Island and to investigate the cost of DR for smaller loads than we have currently worked with. We expect to spend approximately $2 million per year during RCP2 in this area.

This expenditure could, as we originally proposed, be treated as a recoverable item; alternatively it could, as the Commission contemplates, be treated as "contingent". A third option is for the Commission to add the proposed expenditure to the Base Capex allowance[29].

We support the third alternative as the simplest approach. It provides the baseline funding certainty with no obvious downsides.

We appreciate the Commission's concerns with the recoverable option and acknowledge that this, and the contingent expenditure option, would involve additional rule changes to achieve substantially the same outcome as the Base Capex option.

[28] We have a limited cover ($1m per annum with a $1m deductible per event) procured as part of our total insurance package, but have been unable to source pricing for any greater level of cover.

[29] This option is contingent on adoption of the Commission's proposal at Para 3.33 of the Issues Paper

Transactional use: funding the application of DR

Use of DR for Major Capex and Base Capex projects:

- **Major Capex:** the Major Capex framework provides an avenue for funding DR to defer investment in specific large (>$20m) enhancement projects
- **Base Capex:** the DR program to date has shown there is potential to economically defer investment in Base Capex projects. While the Base Capex expenditure adjustment[30] provides some incentive to defer Base Capex, the design of the mechanism may result in inefficient decisions not to defer investment in some situations. For example, where the transaction cost of deferral is less than the benefit of deferral but exceeds the gain available[31] from the Base Capex expenditure adjustment.

We acknowledge that this issue is not in scope of this Issues Paper. However, there may be merit in the Commission considering this at the appropriate time. One option would be to align with the approach provided in the Capex IM for Major Capex projects.

Use of DR for supply emergencies and grid operations

Use of DR for supply emergencies and grid operations:

- **supply emergencies:** there is scope for DR to support the management of supply emergencies. We will work with the System Operator, Electricity Authority and other industry participants to ensure activity in this area fits well with existing and evolving market arrangements. We are not proposing any explicit funding of activities in this area through the IPP
- **Grid operations:** we believe there is scope for DR to assist with efficient operation of the grid (e.g. to help manage outages). This innovation could potentially lower economic costs and reduce risks. We are not proposing any explicit funding but intend to explore opportunities in this area as part of our baseline DR activity

We have further work to do with the System Operator, Electricity Authority and other industry participants to ensure that the DR activities outlined above, and any other applications[32], fit well with evolving market arrangements.

4.7.2. IMPACT OF CATASTROPHIC EVENTS

Greater clarity on how the IPP framework deals with catastrophic events is required. The Orion customised price-quality path highlighted that it is beneficial to have a clear understanding of where catastrophic event risks are expected to lie.

The Transpower IM reasons paper sets out the following explanation:

> "Transpower's IPP may be reconsidered if one of the following events has occurred:
>
> > - a catastrophic event occurs, for which the costs of rectifying the impact of the event is material; […]
>
> In this context, material means that the total effect of the event on the price path is at least 1% of the aggregated forecast MARs for the years in which the costs associated with the event are incurred."

This policy intent is currently implemented through clause 3.7.1 and 3.7.4 of the Transpower IMs. In reviewing our insurance approach for RCP2 we found that the drafting of the operative clause 3.7.1(c)(iv) was not clear:

> "the cost of remediation net of any insurance or compensatory entitlements would have an impact on the price path over the **disclosure years** of the **IPP** remaining on and after

[30] Schedule B1 of the Capex IM

[31] The time value of money associated with the base Capex investment deferral

[32] Any commercial applications of DR would be subject to the Cost Allocation Input Methodology

> the first date at which a remediation cost is proposed to be or has been incurred, by an amount at least equivalent to 1% of the aggregated **forecast MARs** for the **disclosure years** of the **IPP** in which the cost was or will be incurred."

At a minimum, there would be benefit in clarifying this wording.

There would also be benefit in reviewing whether a percentage of remaining aggregate forecast MAR is a suitable way to structure the threshold. A particular difficulty of this approach is that it implies differing expenditure thresholds for capital and operating remediation costs. In practice, the practical impacts of a catastrophic event would be likely to include:

- write-off of some damaged assets, which will itself have a MAR impact;
- a need for repair and replacement Capex. This is likely to 'displace' other Capex to some extent, with consequential impacts on network performance in the medium term and on base Capex needs for the subsequent control period. The revenue impact of this Capex may be less than the revenue impact of asset write-offs and will depend on the extent to which it is possible to deliver the planned Capex programme in conjunction with the additional expenditure driven by the event;
- a transitional uplift in Opex. This may include a short-term uplift associated with responding to an event and its immediate aftermath, and a medium-term uplift associated with restoring network capability to a sustainable level.

In light of the above, it may be more appropriate and more workable to have a threshold defined in terms of the remaining base Capex and Opex allowances, rather than the price path impact.

4.7.3. Refining how the forecast MAR reset mechanism works each year

We support the proposal to simplify the process for making annual updates to the forecast MAR for the remaining years of the IPP. The update process is supported by transparent communications, external audit and Director Certification, and the Commission has discretionary investigation and enforcement powers. We believe that these mechanisms are sufficient to ensure the integrity of our MAR update process.

4.7.4. Use of mid-year cash flow timing assumptions

We appreciate that the building block calculations used in other regulated sectors adopt different cash flow timing assumptions to those used in setting our forecast MAR. However, this is a complex matter that could have a material impact on our revenue. It is, therefore, essential that the Commission provide information, as early as possible, on the details of any proposed changes so that we have sufficient opportunity to review and comment.

4.7.5. Spreading of EV adjustments over more than one year to avoid price shocks

We support inclusion of a mechanism for spreading large EV adjustments over more than one year. We agree that this should be reserved for exceptional circumstances to avoid the risk that the EV accounts accumulate large balances. This mechanism should be available symmetrically – i.e. for exceptional reductions and exceptional increases - to mitigate price shocks for consumers and revenue shocks for Transpower.

4.7.6. Allowing Transpower to voluntarily sets its prices below the forecast MAR

We agree that there should be a mechanism allowing us to set our revenue below our MAR and that we be required to disclose the reason for any such reductions.

We intend to make two voluntary reductions over the course of RCP2:

- in recognition of the contribution that later than ideal planning made to the cost of delivering the North Island Grid Upgrade (**NIGU**) project, we intend to make voluntary reductions with the effect that we will not recover (or receive a return on) $18 million of capital expenditure
- because a portion of our Opex underspend in RCP1 was due to reduced maintenance project work rather than efficiency gains, we intend to make adjustments that reduce the economic benefit we would otherwise obtain under IRIS by $19 million

These adjustments in nominal revenue terms are set out below.

Table 2: Voluntary revenue reductions

$m (nominal)	RCP1	RCP2				
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total revenue (excl. IRIS[33] credits)	954.0	971.9	996.9	1,036.0	1,043.9	1,064.1
IRIS credits	-	13.2	5.4	5.5	-	-
Total revenue (before voluntary adjustments)	**954.0**	**985.1**	**1,002.2**	**1,041.5**	**1,043.9**	**1,064.1**
NIGU adjustment	(4.0)	(4.7)	(5.0)	(5.4)	(5.8)	(6.2)
Maintenance scope adjustment[34]	-	(3.8)	(4.1)	(4.4)	(4.7)	(5.0)
Total Pricing Revenue	**950.0**	**976.6**	**993.1**	**1,031.7**	**1,033.4**	**1,053.0**

4.7.7. Reclassification of Capex and Opex during RCP2

We support this pragmatic modification to recognise that, occasionally, expenditure approved as Capex may ultimately need to be treated under GAAP as Opex.

4.8. The IMs that will apply in RCP2

We look forward to making a separate submission on proposed technical changes to various aspects of the input methodologies that will be used during RCP2.

We have previously engaged with the Commission on the restrictions that apply to modifying IMs with effect within a price path. We remain of the view that a less rigid approach could be adopted for technical changes that do not have a material value impact.

[33] The 'incremental rolling incentive scheme' is designed to strengthen incentives to improve operating efficiency by carrying efficiency credits across control periods.

[34] Although we intend to spread this adjustment over RCP2, we use a discount rate equivalent to our regulatory WACC to make the adjustments economically equivalent to making the entire adjustment in 2015/16.

APPENDIX A: INCENTIVE BASED REGULATION

Transpower is unique in being subject to an individual price-quality path (IPP). Unlike other suppliers in New Zealand, our expenditure and performance targets are subject to detailed scrutiny every five years.

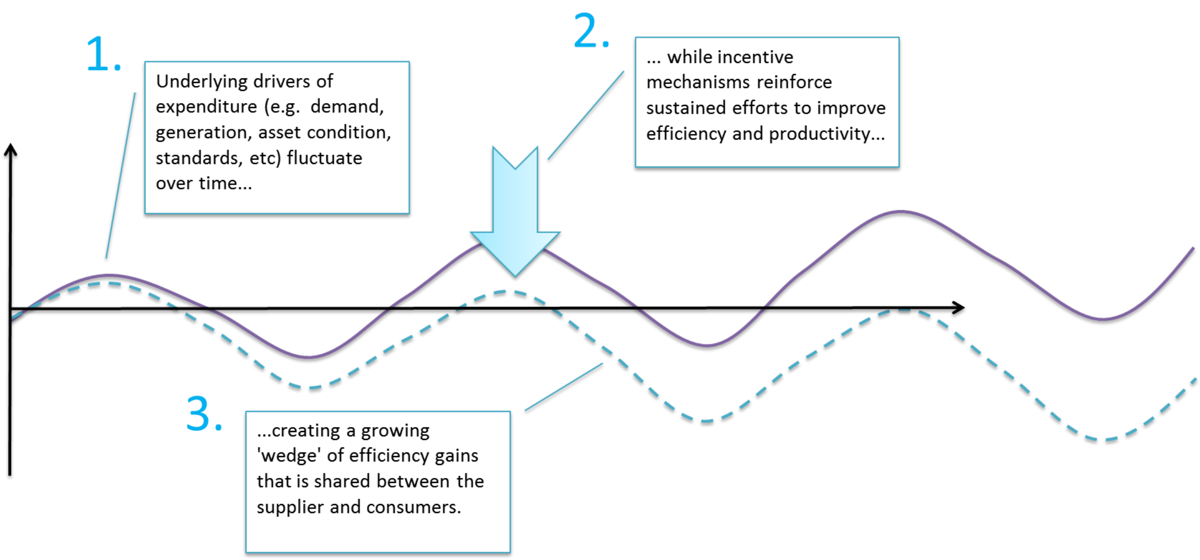
In many regards, RCP2 is the first full-scale application of a 'reset' process that will be repeated every five years in future. Given this, it is important that the reset implementation reinforces the incentive mechanisms designed to promote the objectives of Part 4 of the Commerce Act.

While the Issues Paper and our engagements with the Commission do not give us any strong reason for concern in this regard, it is useful to set out briefly our thoughts on successful operation of incentive-based regulation.

Incentive Based Regulation

The following diagram is a stylised representation of changes in costs over time.

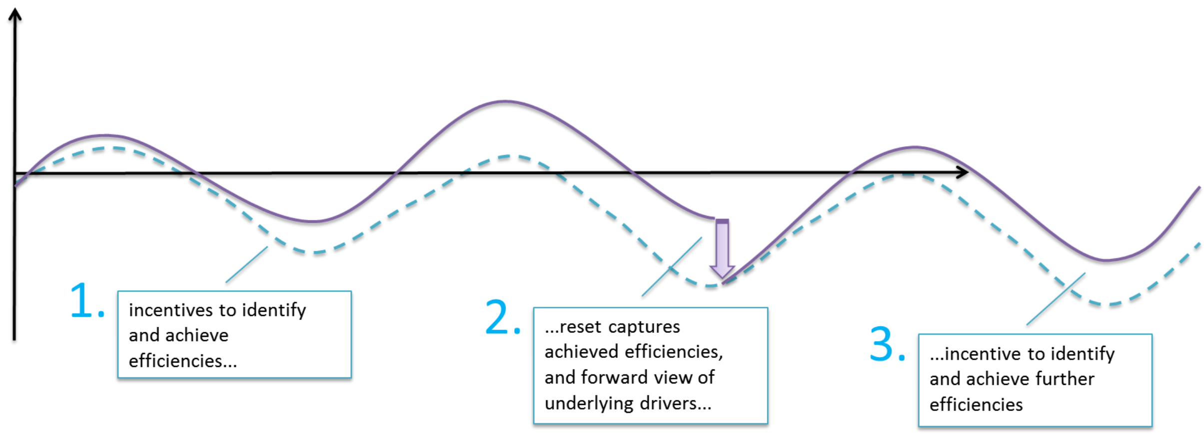
Figure 3: Stylised representation of fluctuating cost drivers, with efficiency overlay



Over time, various underlying drivers lead to a fluctuating need for expenditure (the solid line in the diagram). The regulatory framework incorporates incentive mechanisms designed to reinforce our efforts to pursue business improvements to increase our efficiency while delivering targeted outputs. In the process, we 'discover' a progressively lower cost base (the dashed line). This creates an economic gain that is shared with consumers over time.

Under an IPP framework, this process relies on periodic resets to transfer efficiency gains to consumers. This is illustrated below.

Figure 4: Stylised representation of reset process capturing revealed efficiencies and forecast fluctuations



Conceptually:

- the regulator primarily relies on incentive mechanisms to promote and reveal efficiencies;
- planning is primarily helpful for understanding the impact of achieved efficiency gains and identifying and assessing forecast fluctuations in the underlying drivers over the coming regulatory period.

For the incentive mechanisms to work well, they should operate continuously and should not influence trade-offs between Opex and Capex.

To support these objectives, it is important that successive reset processes establish a track record of predictable, well considered decisions that support confidence in the proper operation of the incentive mechanisms.

In this context, the robustness of our planning process is relevant to understanding whether we have: correctly captured efficiencies achieved to date; have a reasonable view of forward fluctuations in the drivers of expenditure; and properly understand deliverability constraints.

However, if a supplier is responding well to incentives to continuously identify and pursue efficiency gains then its work programme will be responsive and dynamic, and will not adhere rigidly to plan.

APPENDIX B: INDEX AND CLARIFICATIONS

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	MP02	Cover Letter
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	CC01	Director Certification
	CC02	RCP2 Submission Index and Compliance Checklist
Regulatory Templates		
	RT01	RCP2 Forecasts and Revenue
	RT02	Asset Register
	RT03	Performance Measures Model
	RT04	Inflation and Price Input Model
	RT05	Information Schedules
	RT06	Integrated Transmission Plan
	RT07	Other Financial Information
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	PD02	TL Pole
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	PD05	TL Grillage
	PD06	TL Conductor
	PD07	TL Insulators
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	PD09	ACS Outdoor to Indoor Conversions
	PD10	ACS Outdoor Circuit Breakers
	PD11	ACS Indoor Switchgear
	PD12	ACS Power Transformers
	PD13	ACS Buildings and Grounds (includes Buildings and Seismic)
	PD14	ACS Dynamic Reactive Power
	PD15	ACS Capacitors & Reactors
	PD16	ACS Power Cables
	PD17	ACS Structures & Buswork
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	PD19	ACS Disconnectors & Earth Switches
	PD20	ACS Other Station Equipment
	PD21	ACS Other Power Cable Repairs

	PD22	SA Substation Management Systems
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	PD31	Relieve Generation Constraints
	PD32	Upper North Island Reactive Support 2015-2020
	PD33	Bus Section Fault Reliability
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	CR04	RCP2 Self Insurance Quantification (Marsh)
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	BR04	Service Performance Measures
	BR05	Procurement Methodologies for Identified Work Programmes
	BR06	Annual Regulatory Report 2012-13
	BR07	Required Company Information

Further Clarifications on Issues Paper

The following clarifications reflect data and drafting inconsistencies in the Issues Paper.

- Variances discussed in MP01 refer to the three year "Remainder Period" while Chapter 5 generally uses the four year period.
- Paragraph 5.7 should read "is an increase of $70m or 6% (in real terms) relative to its Base Capex for the five year period 2010/11 – 2014/15". These figures do not relate to RCP1.
- The $70m figure does not take into account changes to the E & D threshold.
- Due to the removal of E & D expenditure, Figure 5.1 does not accurately reflect the balance between Grid and total Base Capex in RCP2.
- As applied in the Issues Paper, the term "non-network ICT and Corporate Opex" (e.g., paragraph 5.26) should more accurately read ICT and Corporate Opex (or similar) as it includes total ICT Opex. We have separately identified Grid and non-Grid ICT Opex in our proposal.
- Paragraph 5.22 should read 2010/11 – 2014/15.

APPENDIX C: RESPONSE TO ISSUE PAPER QUESTIONS

No	Question	Response
Q1	To what extent do you consider the approach based on an assessment of Transpower's asset management framework is appropriate?	We are comfortable with the proposed approach.
Q2	To what extent do you think these alternative approaches are suitable?	See section 2.3 of this paper.
Q3	At this stage do you have any comments on Transpower's proposed base Capex expenditure that we should consider?	The main RCP2 submission documents that relate to our proposed Base Capex are set as follows. **Overview** MP01 – Main Proposal – Chapters 2, 4, 5 RT01 – RCP2 Forecasts and Revenue **Grid Capex** MP01 – Main Proposal – Chapter 6 AM02 – Asset Management Strategy AM03 – Planning Lifecycle Strategy PD01-44 – Portfolio Overview Documents FS01-14 – Grid Asset Fleet Strategies **ICT Capex** MP01 – Main Proposal – Chapter 8 IS02 – Information Services Strategic Plan 2013-2020 IS03 – ICT Business Services Strategy 2015-2020 IP01-22 – IT Portfolio Plans **Business Support Capex** MP01 – Main Proposal – Chapter 9 PD45-48 – Portfolio Overview Documents

No	Question	Response
Q4	What are your views on the progress that Transpower has made in delivering the initiatives identified in RCP1, in particular where these initiatives have been used to inform Transpower's plans and justify the resulting proposal of Capex and Opex allowances?	See section 2.6 of this paper.
Q5	To what extent do you consider the current rate of progress for completing GEIP asset management processes for all asset fleets is appropriate?	See section 2.7 of this paper.
Q6	What assessment approaches should we consider where forecast expenditure is not based on GEIP asset management approaches?	See sections 2.3 and 2.7 of this paper.
Q7	To what extent do you consider the proposed level of the productivity adjustment, in light of the rationale given by Transpower, to be reasonable?	See section 2.8 of this paper.
Q8	At this stage do you have any comments on Transpower's proposed Opex expenditure that we should consider?	The RCP2 submission documents that relate to our proposed Opex are set out below. **Overview** MP01 – Main Proposal – Chapters 2, 4, 5 RT01 – RCP2 Forecasts and Revenue **Grid Opex** MP01 – Main Proposal – Chapter 7 AM02 – Asset Management Strategy AM06 – Maintenance Lifecycle Strategy AP02 – RCP2 Maintenance Forecast PD49-53 – Portfolio Overview Documents **ICT Opex** MP01 – Main Proposal – Chapter 8

No	Question	Response
		IS03 – ICT Business Services Strategy 2015-2020 Overview **Corporate Opex** MP01 – Main Proposal – Chapter 9 PD53-57 – Portfolio Overview Documents
Q9	Do you agree that the portion of the benefit that Transpower proposes to forego is appropriate in the circumstances?	See section 2.9 and Appendix A of this paper. We consider it important that the IPP incentive mechanisms are effective, that we demonstrate that we are pursuing best value solutions, and that we take a long-term view on financial value. Taken together, these views have led to our proposed reduction in the economic benefit we would otherwise receive from reduced Opex expenditure in RCP1 (discussed in Section 4.4.5 of MP01). Our decision to make this voluntary reduction does not mean that we consider it appropriate for the Commission to make *ex post* adjustments to incentive outcomes. On the contrary, this would undermine confidence in the operation of the incentive mechanisms and reduce their effect.
Q10	Have you any comment on Transpower's reasoning for voluntarily foregoing part of the IRIS benefit?	See section 2.9 of this paper and our response to Q9 above.
Q11	Do you agree that it is inappropriate to make a similar adjustment for Opex?	See section 2.10 of this paper.
Q12	Do you agree with the cost items chosen for escalation?	See *CR02 - Cost Escalation Forecasts - Frameworks, Forecasts and Forecast Methods (NZIER)* for the rationale for the cost items.
Q13	Do you agree with the choice of indices or reference prices used to escalate the selected cost items?	See *CR02 - Cost Escalation Forecasts - Frameworks, Forecasts and Forecast Methods (NZIER)* for the rationale for the indices.
Q14	Are there alternative sources of information that may assist in evaluating the choice of indices or reference prices?	No comment.
Q15	Do you agree with the methodologies used to forecast cost escalation?	See *CR02 - Cost Escalation Forecasts - Frameworks, Forecasts and Forecast Methods (NZIER)* for the methodologies used to forecast cost escalation.

No	Question	Response
Q16	Is it expected practice for forecast hedging transactions to be taken into account when forecasting cost escalation?	We do not hedge commodities used within Base Capex and Opex. Given this we have assumed that the real price effects realised during RCP2 will impact our actual RCP2 Base Capex and Opex costs.
Q17	Are there alternative forecasting methodologies or forecasts that may provide robust alternative cost escalation forecasts?	No comment.
Q18	Do you have any comments on the link between expenditure and service delivery?	See response to question 28.
Q19	Do you agree that we should set a baseline demand response expenditure Opex allowance?	See section 4.7.1 of this paper.
Q20	Do you agree that we should be considering an approach to approving contingent expenditure if the proposed expenditure is material but has a high level of uncertainty?	See section 4.7.1 of this paper.
Q21	Are there other factors that Transpower could have considered to improve the consultation process?	See Chapter 3 of this paper.
Q22	Are there any important and valuable aspects of consumer service quality overlooked in Transpower's consultation?	See Chapter 3 of this paper.
Q23	To what extent do the proposed measures reflect stakeholder feedback on aspects of Transpower's performance that customers' value?	See Chapter 3 of this paper.
Q24	If the proposed measures do not adequately reflect customer demands, what additional measures do you consider would be most valuable to consumers (for example, energy not supplied, interruptions caused by AUFLS)?	See Chapter 3 of this paper.

No	Question	Response
Q25	To what extend do the criteria that Transpower has used to determine the criticality of the POS reflect feedback from stakeholders?	See section 3.3 of this paper.
Q26	To what extent do you consider that monitoring the performance of 23 circuits will provide a reasonable level of information on the availability of HVAC circuits?	See section 3.3 of this paper.
Q27	To what extent do you consider that Transpower's selection of the HVAC circuits for its HVAC availability measure is adequate and appropriate (AP2)? If you consider that Transpower should also include other circuits, please specify which ones.	See section 3.3 of this paper.
Q28	To what extent do you consider that the *RCP2 targets* proposed by Transpower reflect the level of performance demanded by the customers?	The service customers receive is largely determined by the transmission assets employed to deliver electricity to their connection. The way the Grid is designed and in which assets are used already reflects a trade-off between cost and service. The trade-off is made either through customer choice for dedicated customer-funded assets or through investment decisions for the interconnected Grid and most connection assets. The service customers receive is also determined by how well we manage and maintain our assets and how well we deal with interruptions when they occur. It is our abilities in these areas which our Service Performance Measures seek to reflect. We have developed the measures in consultation with our customers with the aim of making them more reflective of their requirements. To achieve this we sought to make the following improvements. • Change the emphasis of our performance targets to focus on the service we provide. • Ensure our performance measures are meaningful to customers by reflecting what matters most to them. • Produce forward-looking targets that are based on what customers can expect rather than historic performance. • Develop measures and targets that reflect the different categories of customer load or generation at each POS. The RCP2 measures and targets are summarised in Chapter 10 of MP01 with further detail in BR04.

No	Question	Response
Q29	To what extent do you consider that the *long term targets* proposed by Transpower reflect the level of performance demanded by consumers?	See response to question 28.
Q30	Do you consider that reporting on additional customer service measures would be appropriate, and if so, which measures would be most valuable?	See Chapter 3 of this paper.
Q31	To what extent does the incentive rate appropriately reflect the cost to consumers of these interruptions?	The aim for the incentive regime is for us to have a sufficiently strong but proportionate incentive to manage our performance. RT03 – Performance Measures model sets out the value at risk by criticality category for each measure. The incentive rate is a function of the revenue at risk for each measure, and the 'spread' between the cap and collar. We tested our targets using a number of 'sanity' checks: • comparison the proposed spread to actual historic performance • relativity of the incentive rates to each other (e.g. is high priority higher than standard) • modelling of financial outturn against historic performance • relativity of incentive rates to an assessment of the customer cost of interruptions. The last analysis in the list above is contained in section 6.4 of BR04 - Service Performance Measures. This type of modelling cannot be carried out with precision given the limited empirical information available on the true cost of interruptions to individual consumers. As such, the intention was to test that the incentive rates were proportionate to a simple analysis of the cost of interruptions. Accordingly, we used the Electricity Industry Participation Code figure for the 'value of lost load' and made simplifying assumptions regarding the volume of load affected by an interruption. This analysis showed that in each case the incentive rate is not in excess of the estimated consumer cost (i.e. is not too strong) and is of the same order of magnitude.
Q32	What alternative sources of information may assist in evaluating the values proposed by Transpower?	We note that the Electricity Authority has completed research work recently on improved methods for eliciting estimates of the value to consumers of avoiding interruptions. Further work is required to apply the techniques the Authority has studied to a suitably large scale survey to produce granular estimates. As such, this methodology does not yet provide data that could be used to derive incentive rates. It is also not clear that, even if fine grained data were available, that it would be appropriate to simply base incentive rates on this information. For example: • there is a degree of 'double jeopardy' between the revenue linking framework and the indemnity provisions recently introduced to the CGA

No	Question	Response
		• the performance experience by consumers is not solely a function of our performance under Part 4 regulation, but depends on many factors outside our control. For example, current and historical reliability standards (set by the electricity market regulator) have a strong bearing on delivered performance • individual consumer preferences are not time consistent, and we cannot deliver individually tailored performance in any event.
Q33	To what extent should Transpower be exposed to the cost of the interruptions to consumers?	See response to question 32.
Q34	To what extent should individual consumers be compensated for Transpower's failure to meet grid output measure targets, and how?	See response to question 32. We also note that: • targeting compensation at individual consumers would require a departure from the existing revenue setting framework and/or pricing methodology • the CGA indemnity framework does target payments to the consumer requiring a 'remedy'. However the scope and scale of this regime in practice is highly uncertain at present.
Q35	To what extent do you consider this range of performance is appropriate?	We have engaged in multiple rounds of consultation through the development of our measures and targets, and are satisfied that we have put forward an appropriate proposal. We will naturally be interested in any further feedback from our customers and other stakeholders through this consultation process.
Q36	Is it appropriate to include these other aspects of service quality in the grid output adjustment, and if so, how should Transpower be incentivised in relation to performance in these areas?	When developing the long term grid performance measures and targets and consulting with customers, it became apparent that we could not set meaningful targets or even measures for some of the performance areas. In some cases we had doubts regarding the incentives that some measures could create (for example, measures related to outage overruns). We decided to report on some measures only so as to build up experience in the behaviour of the measure. In the future, we will be better placed to place meaningful targets upon these performance measures. An incentive to further develop these measures is appropriate.
Q37	What is your view on the materiality of Transpower's exposure to the new indemnity obligations raised under the CGA?	See section 4.7.1 of this paper.
Q38	Do you have a preferred view on how Transpower's exposure to the (at this time) unknown cost impacts of the amendment to the CGA should be treated for RCP2?	See section 4.7.1 of this paper.