Review of Transpower's Proposed Quality Measures:

How they compare with international practice in Australia and the UK

Report to the Commerce Commission

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Preface

Partna Consulting Group Ltd (Partna) is a specialist energy consulting firm that partners with clients to deliver projects involving investment strategy, commercial strategy and operations, asset management, risk management, organisational change, and energy policy. Established in 2004, we work with clients' across the value chain and have undertaken projects in both New Zealand and Australia.

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Disclaimer

This report has been prepared for the Commerce Commission (the Commission) to assist the Commission's review of Transpower's Expenditure Proposal (the Proposal) for Regulatory Control Period 2 (RCP2). The report has been based on information provided to Partna by Transpower and the Commission as part of the evaluation process. Partna will not be responsible for the accuracy or completeness of the information provided to Partna or any conclusions based on inaccurate or incomplete information. This report is not designed to be used or relied on by any party other than the Commission, and Partna will not be liable in tort, contract or for any other cause of action as a result of the use of this report by others.

Glossary

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator (Australia)
Capex IM	Commerce Commission's Capital Expenditure Input Methodology
Commission	Commerce Commission of New Zealand
EA	Electricity Authority (New Zealand)
EIR	Efficiency Incentive Rate
ENS	Energy Not Supplied
ESC	Essential Services Commission (Australia)
ID	Information Disclosure
IDD	Information Disclosure Determination
Issues Paper	Commerce Commission's "Invitation to have your say on Transpower's Individual price-quality path and proposal for the next regulatory control period – Issues Paper" (10 February 2014)
MAR	Maximum Allowed Revenue
MIC	Market Impact Component
MITC	Market Impact of Transmission Congestion
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NIC	Network Innovation Competition
Ofgem	Office of Gas and Electricity Markets
NGET	National Grid Electricity Transmission
NIA	Electricity Network Innovation Allowance
Output Measures	Grid Output Measures
Partna	Partna Consulting Group Ltd
Part 4	Regulation under Part 4 of the Commerce Act 1986
POS	Points of Service
RCP	Regulatory Control Period
RCP2	Regulatory Control Period 1 April 2015 to 31 March 2020.

RCP3	Regulatory Control Period 1 April 2020 to 31 March 2025 (expected)
RIIO	Revenue= Incentives + Innovation + Outputs
VoLL	Value of Lost Load
SHETL	Scottish Hydro Electricity Transmission Ltd
SO	System Operator
SPTL	Scottish Power Transmission Ltd
STPIS	Service Target Performance Incentive Scheme
The Code	Electricity Industry Participation Code 2010
The proposal	Transpower "Expenditure Proposal for Regulatory Control Period 2" (2 December 2013)
TNSP	Transmission Network Service Provider
TO	Transmission Operator
TPCR	Transmission Price Control Review
WTP	Willingness to Pay

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A. Introduction

1. The Commerce Commission (the Commission) has requested Partna Consulting Group (Partna) to review the Grid Output Measures (Output Measures) proposed by Transpower as part of its expenditure proposal (the Proposal) for Regulatory Control Period 2 (RCP2).[1] The scope of our review included:

    a. The appropriateness of Transpower's consultation process and its proposed measures; and

    b. A comparison with the regulatory practices in the UK and Australia.

2. This report has been peer reviewed by Strata Energy Consulting Ltd and the feedback received has been incorporated.

3. The purpose of a regulated quality regime is to ensure the suppliers of regulated services are incentivised to deliver the services most valued by their customers. Accordingly the measures adopted within the regulated quality regime should reflect this purpose while recognising the asymmetry of information and the level of uncertainty inherent in the practical application of the regime. This alignment between incentives, value and measures is recognised within the Commission's Capex IM[2] (the Capex IM) and is inextricably linked with the expenditure incurred by suppliers. This report is based on the requirements set out in the Capex IM, and our assessment of Transpower's proposal within this overall context.

B. Findings and Recommendations

4. Our findings and recommendations from reviewing Transpower's proposed Output Measures are summarised in this Section. The rationale for our conclusions and recommendations are detailed later in the report.

5. Our findings from the review are:

    a. The customer and stakeholder engagement process utilised by Transpower was appropriate. There appears to be a good level of support from stakeholders for the approach taken and overall it was positively received. We note that submitters have encouraged Transpower to continue in the same vein going forward.

    b. There is also general support from stakeholders for the outcomes of the consultation process. It was considered to be a good start.

[1] The RCP2 period is 1 April 2015 to 31 March 2020.
[2] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.

c. The other measures proposed by Transpower are a good initiative and provide customers with additional information on the operational performance associated with equipment outages.

d. The Capex IM requires the Commission to determine one or more revenue linked Grid Performance Measures[3] and one or more revenue linked Asset Performance Measures.[4] Hence, in our view, if the Commission adopted Transpower's proposed measures these high level requirements in the Capex IM would be met.

e. However, the additional question is whether the proposed measures are effective and aligned, to the greatest extent practicable, with customer value preferences over the longer term.

f. Two themes were raised by stakeholders throughout the process and in our view were only partially addressed by Transpower. These themes were also raised again in submissions on the Commission's Issues Paper. These are:

- The economic impact of interruptions; and
- Measuring the market impact of all outages (planned and unplanned).

g. In regard to these issues, and Transpower's current approach, we note that:

- Unnecessary reliance on composite or proxy measures carries significant risk of creating perverse incentives and risks inefficient outcomes (particularly over the long term) ; and
- The service outcomes associated with these themes can be measured directly and are done so in the UK and Australia.

h. Therefore in our view Transpower's proposal can be classed as a good first step in the right direction. However, the efficacy of the proposed measures over the long term and the alignment of Transpower's incentives with customer value over time should be developed further. In light of this we would recommend the development of measures that directly monitor the economic impact of interruptions on customers (by way of an example through the use of energy not served measure) and a market impact measure.

i. This recommendation is based on strengthening, over the longer term, the alignment of Grid Outputs with the criteria within the Capex IM.[5] A review of the measures utilised internationally further supports submissions made by stakeholders on Transpower's proposal and our recommendation to encourage the further development of quality measures that signal the economic impact of interruptions and the market impact of asset outages.

j. An initial revenue at risk of ±1% is in line with the starting incentive levels utilised internationally. In Australia Version 1 of the STPIS[6] utilised 1% on reliability measures.

[3] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, clause 2.2.2 (1)(c)(i).
[4] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, clause 2.2.2 (c)(ii).
[5] *Transpower Capital Expenditure Input Methodology Determination [2012] NZCC 2, clause A5 and A6, Schedule A.*
[6] Service Target Performance Incentive Scheme.

From Version 2 of the STPIS incentives moved to range from -1% to +3%.[7] The UK currently utilises an incentive range of -4% to +1.5% of MAR for transmission.[8] Over the longer term any total incentive revenue of between ±1% and ±4% would be in line with current international practice.

k. In regard to customer satisfaction, we note that under RIIO-T1 Ofgem places an incentive of ±1% of MAR on Transmission Operators to develop and refine a customer/stakeholder survey. In addition there is a discretionary +0.5% on effective stakeholder engagement that has delivered exceptionally positive outcomes for customers. In their proposal Transpower does not propose any customer satisfaction or engagement measures nor have they sought feedback on these. Given the objective of the framework is to ensure Transpower deliver value to their customers, at least reporting on customer satisfaction would, in our view, be warranted.

l. In our view, the categorisation of GXPs or Points of service (POS) as proposed is a useful mechanism for establishing the relative security and performance criteria and ultimately the investment requirements for each class of POS. However, we note that an integrated investment strategy that delivers on customer outputs will require Transpower to translate these broad performance standards to expenditure proposals that are both location specific and reflect fleet based asset health outcomes.

m. There is the additional risk that establishing the POS categories in the manner proposed will incentivise inflexibility in supplying a level of quality sought by a customer when it differs from the “average” within each class. As such, our view, in much the same manner as the proposed measures, is that the proposed POS categories should not be considered a final destination but rather a first step towards implementing a criticality framework, and Transpower should be encouraged to continue its development so as to more closely align the outputs sought by customers with expenditure.

n. We also note that with such a small number of direct customers there is no reason why customer specific interruption performance standards could not be developed. Developing customer specific performance standards should be the ultimate objective and is consistent with being a service based transmission company. Obviously specific customer defined outputs would need to account for the network configuration and asset health conditions within each applicable region.

o. We also note there is an additional minor point of difference between what Transpower have proposed and the outage duration measure utilised in Australia. Specifically, Transpower have proposed that interruption durations are capped at 24 hours whereas in Australia event durations are capped at 7 days.

6. As a result of these findings, we recommend that:

[7] Excluding any innovation or development related incentives.
[8] Excluding any innovation, development or safety related incentives.

a. The Commission accept Transpower's proposed measures as a good first step, recognising the engagement process Transpower has undertaken and the feedback received from stakeholders;

b. The Commission encourage Transpower to develop measures that signal the economic impact of interruptions on customers (such as on energy not served) and the market impact measure of outages. This should be done during the remainder of RCP1 and the commencement of RCP2 to position the measures for deployment in RCP3;

c. The Commission encourage Transpower to continue the development of an integrated investment strategy to reflect the outputs sought by its customers. This involves the deployment of both asset health indicators and criticality. The POS categories identified are a start in this direction but not sufficient within themselves. We recommend that the publication of an integrated transmission plan as envisaged within the Capex IM is a useful mechanism in this regard; and

d. The Commission encourage Transpower to continue along a customer centric development path by agreeing with customers POS performance levels that are both individualised and based on the network configuration and asset health conditions within their region. We recommend that this is completed in time for implementation in RCP3.

7. We note that the Commission is considering the specific parameters of the cap, collars and incentive rates proposed by Transpower and as such is outside the scope of this report.

C. Our Approach

8. The Capex IM sets out the requirements for the Commission's evaluation of the Output Measures proposed by Transpower. This is referred to in the Issues Paper[9] where the Commission states it "will apply the Capex IM criteria in considering Transpower's proposed grid output measures and the relationship between service performance and revenue."[10]

9. Therefore, to assess Transpower's proposal we have considered these requirements in light of Transpower's current capability and proposed development path. Specifically there are four key areas within the Capex IM that relate to the scope of our review. These are:

a. The extent to which Transpower's proposal satisfies the required specification of the measures within the Capex IM. The Commission is required to determine one or more measures of grid performance and one or more measures of asset performance.[11]

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[9] Commerce Commission, "Invitation to have your say on Transpower's individual price-quality path and proposal for the next regulatory control period – Issues Paper" (10 February 2014).

[10] Commerce Commission, "Invitation to have your say on Transpower's individual price-quality path and proposal for the next regulatory control period – Issues Paper" (10 February 2014), paragraph 4.19.

[11] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, clause 2.2.2(1)(c)(i).

Transpower has the option to propose asset capability, asset health, and other measures;[12]

b. The extent to which the measures proposed by Transpower relate to the services that are valued by customers. This is evidenced by stakeholder responses to Transpower's consultation, submissions made in response to the questions raised within the Commission's Issues Paper, and the quantification of the value associated with the services;

c. The extent to which the proposed measures are recognised as a measure of risk and or performance in the supply of transmission services. This is evidenced by whether the measures proposed by Transpower are recognised internationally as being suitable for both monitoring and incentivising Transpower's performance over time. As noted in the Issues Paper:

   "In setting the IPP for RCP2 we will be considering and commenting on the direction we expect the IPP to take in the future. In doing so, we will draw on the experience with the incentive regulation in other jurisdictions such as the UK and Australia."

d. Whether the measure is quantifiable, controllable by Transpower, auditable and replicable over time. These are key criteria for performance measurement and go to the heart of its practical application.

10. Within the Capex IM it was also envisaged that the Output Measures should have a strong linkage with expenditure. This is evident within the requirements for an Integrated Transmission Plan (ITP).[13] By way of example the ITP is to include the key relationships, including any synergies and trade-offs within and between projects, programs and forecast grid outputs[14] and how the key uncertainties and key risks will affect the ability to deliver the forecast grid outputs.[15]

11. In assessing quality measures it is also important to consider a broad perspective on the interrelationships involved to ensure that as a whole the incentives faced by a supplier collectively align to achieve regulatory objectives. There are six dimensions involved:

    a. The overall legal and economic framework under which the quality measures are being established. Part 4 of the Commerce Act 1986 contains the primary purpose and obligations under which the Commission operates and regulates electricity network companies. The Capex IM has been established to provide more detailed guidance for the application of those principles to Transpower's capital expenditure and the IPP for operational expenditure;

    b. Defining the aspects of transmission service that customers' value the most and the quantification of that value. Understanding and delivering on customer value preferences is core to Transpower becoming more of a service based transmission company;

[12] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, clause 2.2.2(1)(c)(ii).
[13] Transpower Capital Expenditure Input Methodology Determination [2012] NZCC 2, clause 3.1.1.
[14] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, Schedule E2.
[15] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, Schedule E2.

c. The efficacy of the measures selected to incentivise Transpower's delivery of transmission services valued by their customers. This must take into account the practical realities of operating a transmission network while also encouraging innovation and development. This also includes striking the right balance between leading and lagging measures and incentives created by each. Measures that are proven to be effective internationally provide a good benchmark for this dimension;

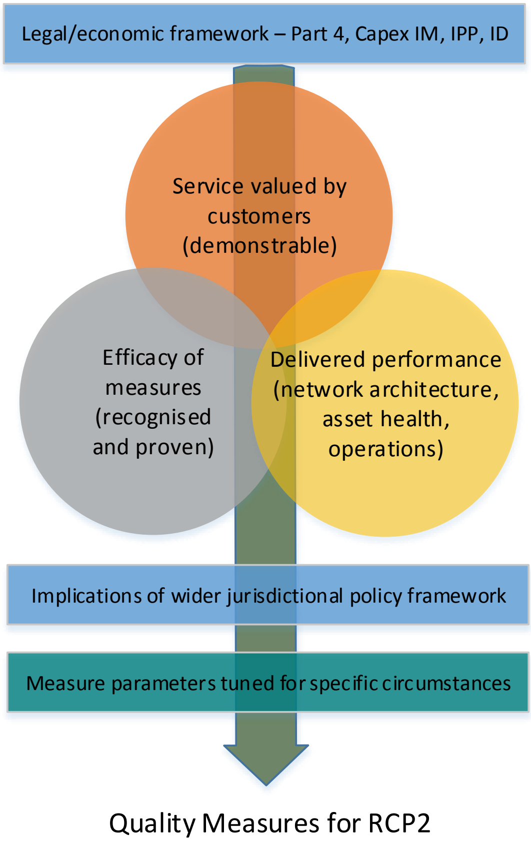
d. Transpower's performance in delivering transmission services is a function of the network architecture and capacity supplying each location, the status and health of Transpower's asset fleet and operational practices. Aligning these aspects with customer value and service delivery is core to investment strategy and the development of an ITP as envisaged in the Capex IM. In other words, good investment strategy is the essence of what is required to be a service based transmission company;

e. Accounting for the wider policy environment to ensure that the broader incentive framework is consistent and does not result in perverse outcomes. In this instance it includes the reporting requirements Transpower has under the Electricity Industry Participation Code (the Code); and

f. Aligning specific measurement parameters to the circumstances of the regulated entity. By way of example, where more than one transmission operator exists within a single jurisdiction, company specific parameters are typically applied for each measure. In this case parameters will be tuned to account for circumstances faced by Transpower.

12. These dimensions of the quality framework are illustrated in Figure 1 below.

Figure 1 - Dimensions of the quality framework



13. The challenge faced when establishing Transpower's quality measures for RCP2 is working through these dimensions to ensure consistency within the framework as a whole.

14. As the scope of this report is concerned with dimensions b, c and e and their application within the Capex IM and regulatory practice in Australia and the UK, these are addressed in the following sections:

    - Transpower's engagement with its customers and stakeholders to establish the aspects of service they value (refer to Section D);
    - Alignment of the proposed measures with the requirements in the Capex IM, Transpower's response to customer feedback and the establishment of the proposed POS categories (Section E);
    - A comparison of Transpower's proposal with the regulatory practices in Australia and the UK and the evolution of the regulatory regimes (Section F); and
    - Our conclusions from the review (Section G).

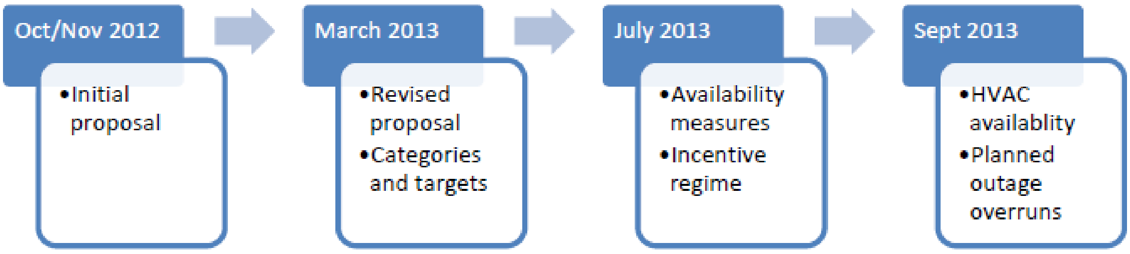
15. More detail on the transmission arrangements in Australia and the UK and a high level comparison between these regimes and Transpower's proposal is provided in Appendices B and C.

D. Transpower's customer engagement

16. Understanding and aligning investment with the level of service sought by customers is fundamental to developing a sound investment strategy and the effective operation of a service based business. This is reflected in Schedule A of the Capex IM where consideration must be given to the extent that the output being measured is valued by consumers, the relationship between the value of the output to consumers and the incentive rate, and the quantification of the relationship between expenditure and the Output Measures.

17. Effective engagement with stakeholders and customers is a first step along this journey. This section sets out our findings from our review of Transpower's engagement process and the alignment of the proposed measures with the feedback Transpower received from its customers.

18. The engagement process embarked on by Transpower included a number of workshops with stakeholders, development of working papers and consideration of submissions. The following diagram extracted from Transpower's proposal[16] shows the steps Transpower has undertaken.



19. While a more substantive consumer engagement process is required in other jurisdictions such as the UK, the approach taken by Transpower appears to have been thorough. As such, we consider that it was appropriate and well supported. This is summarised by Carter Holt Harvey in their submission dated 3 March 2014:

"We appreciate the positive approach Transpower have taken to the development of customer facing performance measures. We believe that this has resulted in a proposal for RCP2 that has made a significant improvement from the measures used in RCP1 and demonstrates that Transpower have made good progress in their focus on all customers."[17]

20. This is echoed by other submitters on the Commission's Issues Paper:

"Transpower engaged in a positive and open manner in developing customer facing performance measures. This aligns with experience from members "in the field" with Transpower staff and contractors becoming more end customer focussed."[18]

[16] Transpower "Expenditure Proposal for Regulatory Control Period 2" (2 December 2013), p. 122.
[17] Carter Holt Harvey "Transpower RCP2 submission" (3 March 2014), pg 1.
[18] Major Electricity Users' Group "Transpower RCP2 submission" (3 March 2014), pg 1.

"We would also like to endorse Transpower's approach, as we felt fully consulted and had many opportunities to comment and respond to the proposed service measures."[19]

"The consultation process carried out by Transpower included a number of steps in the process and provided sufficient time and provided sufficient information to allow customers to participate fully in the process."[20]

21. Together submitters', in our view, have endorsed the process Transpower has undertaken. We also note that submitters have encouraged Transpower to continue the development of these measures in a similar vein:

"That journey has just begun and we hope the Transpower Board, senior management and line staff accelerate that change."[21]

"We hope that this on-going focus on customers by Transpower will continue and improve. We as customers also will continue to work to improve this relationship."[22]

E. Transpower's proposed measures and customer feedback

22. This section sets out our findings from the review of Transpower's proposed measures in light of the feedback received from Transpower's customers. In its proposal Transpower state that the feedback received has shown that transmission customers value:[23]

- The ability of Transpower to provide service without interruption;
- The impact outages have on the market;
- The need for prompt accurate communications during unplanned outages;
- The financial impact of interruptions; and
- Power quality issues.

23. Having reviewed Transpower's consultation and submissions we agree with this summary. We do note there is an inconsistency between Transpower's detailed report (BR04) and their proposal. The more detailed description also includes "how often customers are at a greater risk of unplanned interruptions" as an additional feature that is important to customers.

24. In addressing this feedback Transpower have proposed measures that relate to the first three of these value preferences. The proposed measures consist of three Grid Performance measures

[19] Powerco "RE: Cross submission on the Issues Paper on Transpower's individual price-quality path and proposal for the next regulatory control period" (10 March 2014), pg 1.
[20] Carter Holt Harvey "Transpower RCP2 submission" (3 March 2014), pg 3.
[21] Major Electricity Users' Group "Transpower RCP2 submission" (3 March 2014), pg 1.
[22] Carter Holt Harvey "Transpower RCP2 submission" (3 March 2014), pg, 1.
[23] Transpower NZ Ltd, "Expenditure Proposal, Regulatory Control Period 2", December 2013, p. 122.

(GP1, GP2, GP3)[24] and two Asset Performance measures (AP1, AP2) with a total MAR at risk of ±1%, allocated 80% (±0.8%) to Grid Performance and 20% (±0.2%) on Asset Performance. Transpower have also proposed six other reporting measures, not linked to revenue incentives. These are discussed further below.

25. The Capex IM requires the Commission to determine one or more revenue linked Grid Performance Measures[25] and one or more revenue linked Asset Performance Measures.[26] Hence, in our view these high level requirements in the Capex IM would be met should Transpower's proposed measures be accepted by the Commission.

26. We note that at Transpower's request, the Commission may determine one or more revenue linked measures for asset capability, asset health measure or any other measure. While we consider that the addition of asset capability or asset health measures would have been beneficial, as far as we are aware Transpower has not made such a request.

27. Transpower have proposed six other measures. Together these other measures provide Transpower's customers with additional information on the operational performance associated with network events and equipment outages. None of these other measures are proposed to be revenue linked and as such fall outside of the Capex IM requirements. They are however being offered by Transpower in addition to the reporting obligations Transpower have under the Commission's Information Disclosure (ID) requirements. We also note that reporting on the time that customers are placed on N security is a good step towards a more leading indicator of reliability performance.

28. We believe the development of the other measures is a good initiative from Transpower and, based on the observed stakeholder feedback would recommend that the Commission encourage Transpower to develop these further.

Transpower's response to customer feedback

29. To assist in reviewing Transpower's proposal we have set out a comparison of the proposal with its initial position to illustrate how stakeholder feedback has influenced its submission. This is illustrated in Table 1 below.

Table 1 - Comparison of Transpower's initial and final proposal

	Initial position – October 2012[27]	Final proposal – October 2013
Grid Performance	• Number of unplanned interruptions > 1min with targets varying by customer category	• GP1: Number of unplanned interruptions >1min caused by faults in TP network. • GP2: Average duration of unplanned interruptions.

[24] Refer to Appendix A for the full list of measures proposed by Transpower for RCP2.
[25] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, clause 2.2.2 (1)(c)(i).
[26] *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, clause 2.2.2 (1)(c)(ii).
[27] Summarised from Transpower *"Customer-Facing Performance Measures Consultation Paper"* (October 2012).

	• Duration of Interruptions – Average and P90 • Transpower proposed to include interruptions caused by extreme weather or environmental conditions.	• GP3: P90 unplanned interruption duration, which reflects the duration of our longer interruptions. • Targets vary for different customer category. Events caused by extreme weather or environmental conditions included. 80% of revenue at risk
Asset Performance Measures	• None Proposed	• AP1: Energy availability of HVDC circuits • AP2: Availability of selected HVAC circuits • 20% of revenue at risk
Other Measures (reporting only)	• Information Provision during interruptions: • Inform with 15 min. • Communicate initial assessment and time to restore within 30mins. • Provide hourly updates • Accuracy of estimated restoration time +/- 15 min • Transmission Interruptions compared to distributions (this has been dropped).	• OM1: Time to provide initial information following an unplanned interruption (15 min) • OM2: Time to provide updated information following an unplanned interruption (30 min) • OM3: Accuracy of notified restoration times following unplanned interruptions • OM4: Extent that we meet planned outage restoration times • OM5: Extent to which we place customers on 'N' security • OM6: Number of unplanned momentary (less than one minute duration) interruptions. • Only OM1 and OM2 have targets set. OM3, 4, 5 and 6 are reporting measures only. These Other Measures are not linked to revenue.

30. As shown in Table 1, over the course of the consultation Transpower adopted availability measures, simplified the proposed grid performance measures and fine-tuned the proposed reporting measures.

31. As such we consider that many aspects of the feedback received from submitters appear to have been accounted for within the proposal.

32. However, in reviewing the feedback received, we note that two themes were raised by stakeholders throughout the process and were raised again in submissions on the quality questions within the issues paper. These relate to:

- The economic impact of interruptions; and
- Measuring the market impact of all outages (planned and unplanned)

33. This is evidenced in the submissions to Transpower on unserved energy and economic impact:

"We support the proposed use of the Electricity Authority work presently under development in establishing improved VOLL measurements as a basis for reporting and eventually developing economic impact targets." And *"We recommend that a project timeline be developed in conjunction with the Commerce Commission, Electricity Authority, Transpower and customers to*

allow the use of economic impact on customers on loss of supply to be included in the measures without targets category during RCP2.[28]

"Over the last 20 years, we have kept a list (non-exhaustive) which outlines most of the interruptions (both short and not so short) that we have experienced. Against each entry, we place a dollar figure as to how much each interruption is estimated to have cost the company. We can provide this information to you and it should be recorded by Transpower."[29] And *"Information on economic impact should be included."*[30]

"However, we also believe that depending on the time of day/day of week/season, not all outages (even those of the same duration) are necessarily equal due to fluctuations in demand/injection. For this reason we would support the inclusion of a "MWh impact" type of measure alongside the number and duration measures to provide further context. This MWh impact could estimate unserved energy and/or lost injection due to outages at a given customer point of service."[31]

34. And, on market impact:

"we suggest that Transpower includes a new performance measure that identifies and seeks to minimise the market impact of all planned outages. We consider that such a performance measure will demonstrate your commitment to customers well-being and the on-going effective operation of the New Zealand electricity market." And "market impacts of outages are an important indicator for customers"[32]

"Proposed measures only take account of outage duration and frequency, and do not consider market impacts. Transpower has proposed performance measures relating to the frequency and duration of unplanned outages, and information provision during power outages. We agree that such measures are appropriate. However, we consider that Transpower should also develop measures relating to the market impact of their grid management decisions." And *"Meridian does not consider that the existing net benefit test applying to grid outage decisions provides sufficient incentive for Transpower to take account of market impacts."* And *"In a competitive market, Meridian would select a transmission provider that sought to minimise the impact on market outcomes (i.e. wholesale price movements) of its grid management decisions. As such, Meridian considers that the grid operator should face appropriate incentives under Part 4 of the Commerce Act to minimise the market impact of transmission outages."*[33]

"However, it would be valuable to ascertain the extent to which outages contributed to market losses and constraints. Measures of this nature could also help guide Transpower in its outage planning processes."[34]

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[28] Carter Holt Harvey, "Revised Proposal on Customer-Facing Grid Performance Measures submission" (April 2013), pg, 4.
[29] New Zealand Steel "Customer-Facing Grid Performance Measures submission" (December 2012), pg 1.
[30] New Zealand Steel "Customer-Facing Grid Performance Measures submission" (December 2012), pg 2.
[31] Mighty River Power "Transpower Proposed Grid Performance Measures" (5 December 2012), pg 2.
[32] Genesis Energy, "Customer-Facing Grid Performance Measures" (3 December 2012), pg 2.
[33] Meridian "Customer-Facing Grid Performance Measures" (5 December 2012), pg 2.
[34] Mighty River Power, "Transpower Proposed Grid Performance Measures" (5 December 2012), pg 3.

35. As noted above these themes were raised again within submissions and cross submissions to the Commission's issues paper:

"further work in refining the measure of cost of interruptions to consumers should be carried out to ensure that the signals are as accurate as possible. The work carried out by the EA and summarised in their reports on Investigation into the Value of Lost Load in New Zealand dated 23 July 2013 and 16 January 2012 provide some information that is an improvement on the standard VOLL."[35]

"Meridian strongly supports adopting measures based on actual market effects of grid outages. Over time, the wholesale market impacts of grid outages faced by sellers and purchasers will flow through to end consumers. Such impacts are therefore a relevant consideration under Part 4 of the Commerce Act." And *"In addition to the availability targets proposed, we encourage the Commission to consider the introduction of performance measures relating to market impact in RCP2. With the commissioning of Pole 3 and the upgrade of Pole 2 control systems complete, operation of the HVDC link will be more stable over the RCP2 period. It would therefore be an appropriate time to introduce market-based HVDC performance measures into the regulatory framework ."* [36]

"MEUG agrees with the submissions of Carter Holt Harvey and Meridian Energy Ltd. The latter suggested various strategies to improve forecasting and management of annual wash-ups, and introducing some market impact and other measures into the revenue-linked regime in RCP2."[37]

36. In our view, Transpower have only partially addressed these issues within the proposed output measures. The combination of interruption frequency, outage duration applied demand by POS classification provides an approximation for the energy impact of an interruption for demand customers and appropriately tuned incentive rates (reflecting an approximation of VoLL) would then signal an approximation to the economic cost of an interruption. Significantly, Transpower have stated that they have not addressed the financial impact of interruptions, but that they *"will continue to discuss other aspects of our performance with customers with the view of developing our performance measures in the future."*[38]

37. Likewise the asset availability measures have been proposed as a proxy for measuring market impacts directly.

38. In its cross submission Transpower simply note that:

"We have followed the work undertaken by the Electricity Authority to date. We are happy to work with the Electricity Authority on any further analysis undertaken in this area."[39] And *"Performance Measures AP1 (HVDC availability), AP2 (HVAC availability) and OM4 (planned outage restoration times) are three measures that relate to market impact. We selected the*

[35] Carter Holt Harvey, "Transpower RCP2 submission" (3 March 2014), pg, 5.
[36] Meridian Energy, "Transpower RCP2 submission" (March 2014), pg 2.
[37] MEUG, "Transpower RCP2 cross-submission" (10 March 2014), pg 1.
[38] Transpower, "Service Performance Measures", 1 October 2013, pg 10.
[39] Transpower "Feedback on Stakeholder Submissions" (10 March 2014), pg 4.

HVAC circuits that have the greatest effects on market outcomes to form the basis of AP2. We intend to assess AP1 and AP2 during RCP2."[40]

39. Therefore, in our view, and given the strength and consistency of the submissions throughout the engagement process, serious consideration should be given to developing the proposed measures further to ensure they are most effective in addressing stakeholder feedback in a manner that will align Transpower's incentives with customer value over time.

40. A key consideration in this regard is whether a service outcome that is valued by customers can be directly measured (i.e. is quantifiable through a single measure rather than via a composite of two or more measures) in a way that is auditable and replicable over time. Targeting incentives on these outcomes directly is far more likely to encourage efficient behaviour in the delivery of the outcome than reliance on a composite of measures to approximate the impact. In addition direct measurement allows the economic cost of non-performance to be directly signalled.

41. Another consideration is that reliance on a composite or proxy measures can in some instances lead to perverse outcomes. By way of example, in this instance the long term targeting of increased circuit availability (as currently proposed) runs the risk of creating an incentive to inefficiently reduce maintenance on key network assets, or undertake inefficient operational practices. Rather the focus or purpose of the availability measures, as stated by Transpower in their proposal, is in relation to the impact that asset availability has on electricity flows and consequently on the electricity market.[41] In practice achieving the market objective requires scheduling of outages in such a way as to maximise efficiency by considering the trade-off between the cost of undertaking maintenance and the impact on wholesale electricity prices.[42] Rather the use of availability as a measure risks creating incentives for not undertaking the work at all (or at an inefficient level) due to a potential breach of an availability target and does not provide a signal as to the appropriate time period for scheduling outages. In the longer term under investment in asset maintenance and poor scheduling decisions will have a much larger impact on consumer welfare than availability. Therefore, in our view direct measurement and targeted incentives are far better in the long term.

42. Consideration of the measures utilised internationally is also useful in this regard. These are covered in more detail in the Section F below. However, it is suffice to note here that:

- Measures more directly related to the economic impact of interruptions are utilised within both Australia[43] and the UK;[44]
- In its latest version of the STPIS, Australia has dropped availability as a measure in favour of circuit outage rate as a leading measure for reliability;[45] and

[40] Transpower "Feedback on Stakeholder Submissions" (10 March 2014), pg 3.
[41] Transpower "Service Performance Measures", in Transpower Expenditure Proposal for Regulatory Control Period 2 (2 December 2013), BR04, pg 21.
[42] More ideally the impact on consumer prices would be accounted for, but this is not practicable.
[43] Australia utilises the number of events that breach system minute thresholds. System minutes are a normalised measure of unserved energy.
[44] The UK utilises a direct measure of unserved energy.
[45] Availability was not used as a measure of market impact.

- Australia has operated with a direct market impact measure since 2008.

43. Therefore, in our view, while the outcome of Transpower's engagement has resulted in a first step in the right direction, there are a number of compelling reasons to suggest that Transpower should consider measures that more directly reflect the outputs valued by customers. It is also likely that the use of unserved energy (or other measures that can reflect the economic impact of interruptions) and a direct market impact measure will simplify the proposed quality regime over the long term and avoid the addition of more composite measures in the future. That is, in our view there are more suitable measures that will likely provide long term efficiency benefits over those selected.

44. However, we do note that deployment of an unserved energy and market impact measures will take development time to ensure that they are appropriately parameterised for the New Zealand environment. While we consider that the timeframe required to develop the details of such measures, and select the appropriate initial parameter values would not be significant, it is both prudent and a practical requirement to allow for a phased development over the remainder of RCP1 and the beginning of RCP2. This will allow for deployment and revenue linking in RCP3.

45. Consequently we recommend that the Commission encourage Transpower to develop and report on a measure of economic impact of interruptions to customers (such as on energy not served) and a market impact measure during the remainder of RCP1 and RCP2. Given these are not difficult to develop we would recommend that the measure definitions are completed within the first 12 months of RCP2, which allows 24 months development time.

46. In the short term we note that the parameters for the reliability measures proposed could be tuned to provide a representation of the longer term approach. In other words the incentive rates, caps and collars and overall revenue at risk for GP1 to GP3 could be tuned to collectively approximate VoLL. This approach would be consistent with the Capex IM that requires the consideration of relationship between the value placed on the output being measured and the incentive rates. In particular this would also be consistent with the practice in the UK as discussed in Section F below.

47. We also note Transpower have not proposed any measures associated with customer satisfaction, nor did they seek any feedback on such a measure within their consultation. Transpower's response to any suggestions in this regard has been unequivocal when they state:

    "We do not support having additional customer service measures in RCP2. Our annual customer survey provides our customers the opportunity to provide feedback on these matters and others."[46]

48. However, given the objective of the framework is to ensure Transpower deliver value to their customers, at least reporting on customer satisfaction would, in our view, be entirely warranted and be a significant step towards being a service based transmission company. We note that customer and stakeholder engagement is a significant component in the UK regulatory regime

[46] Transpower, "Feedback on Stakeholder Submissions" (March 2014), pg 3.

with up to ±1.5% MAR placed on a Transmission Operators' stakeholder engagement and satisfaction performance.

Development of the Point of Service (POS) categories

49. Transpower have defined five POS categories, classifying them from High Priority to N-security, differentiated to reflect the different levels of service expected.[47] In its submission Transpower state that for most load, the categories are based on a customers' relative criticality. In regard to Transpower's POS categorisation, submitters in Transpower's engagement process have, by way of example, noted:

    "We agree that the customer segmentation is a useful exercise. However, we suggest that the identification of these customer segments should take place with clear consultation with those customers that make up the segments. Furthermore, once the segments are clearly identified, ideally we would expect to see different levels of service reflected in the associated Transpower costs for those segments."[48]

    "A good first step. In the longer term an economic metric should be used to rank the importance of GXP."[49]

    "We agree in principle with the description of the types of customers that should be included in the "essential", "important" and "standard" categories. Once the categories are established, we anticipate further discussion about which particular customers should be included in each group."[50]

50. In our view, the categorisation of GXPs or POS in this manner is a useful mechanism for establishing the relative security and performance criteria and ultimately the investment requirements for each class of POS.

51. However, while Transpower's proposal may be a useful starting point, we note that Transpower will have to translate these broad performance standards to expenditure proposals that are both location specific and reflect fleet based asset health outcomes in order to develop an appropriate investment strategy. A critical step in establishing investment strategy is to develop and understand the implication of service levels for grid expenditure going forward for the combination of POS, transmission assets deeper into the grid, and operational costs. Delivery on service levels is then a function of the assets and processes actually deployed over time. The combination of both a "top down" service definition and "bottom up" asset and operations approach is required to achieve the outcomes sought by Transpower's customers. As such, in our view, the proposed POS categories should not be considered a final destination but rather a start in the right direction.

[47] Transpower "Service Performance Measures", in Transpower *Expenditure Proposal for Regulatory Control Period 2* (2 December 2013), BR04, p. 15.
[48] Genesis "Customer-Facing Grid Performance Measures" (3 December 2012), pg 2.
[49] MEUG, "Consultation Paper - Customer-Facing Grid Performance Measures" (5 December 2012), pg 3.
[50] Powerco, "Re:Customer-Facing Grid Performance Measures submission" (5 December 2012), pg 4.

52. We also note that with such a small number of directly connected customers there is no reason why customer specific interruption performance standards could not be developed. Developing customer specific performance standards should be the ultimate objective and in our view is consistent with being a service based transmission company. In doing so the common use of core transmission assets will obviously need to be acknowledged and accounted for along with the interrelationship between service levels of customers within each region. We note that with the POS being location independent the current proposal can at best only partially achieve the broader linkage between outputs and expenditure. There is also the additional risk that establishing the POS categories in the manner proposed will incentivise inflexibility in supplying a level of quality sought by a customer when it differs from the "average" within each class.

53. Therefore, we would recommend that the Commission encourage Transpower to continue along this customer centric development path by agreeing with customers POS performance levels that are both customer specific and based on the network configuration and asset health conditions within their region. We would recommend that this is completed in time for implementation in RCP3.

F. The International Approach

54. Internationally regulators and companies have extensive experience[51] in establishing and operating under price quality regimes that utilise relatively simple but effective measures for incentivising suppliers to deliver the outcomes sought by consumers. Therefore, in our view significant benefit can be gained by considering the approach taken in these regimes. Undertaking such a review provides the opportunity to learn from others experience without exposing New Zealand consumers to the potential downsides of the transition international regulators, suppliers and consumers have faced. Consideration of the measures utilised within these jurisdictions also provides an independent perspective on the type of measures that can be classed as recognisable measures of risk and performance in the supply of transmission services.

    However, we do note that care must be taken to ensure that any comparisons account for differences in the overall policy framework and environment within the New Zealand context. Accordingly, for the purposes of this report, we have considered the quality measures utilised in Australia and the UK and compared them with those proposed by Transpower. Consideration of the detailed parameters for the measures is outside the scope of this report and the Commission is considering the specific application within the New Zealand context.

55. A more detailed description of the Australian and UK regimes are described in Appendix B.

High level comparison between regimes

56. There are a number of specific requirements in each regulatory jurisdiction that drives differences in approach to regulation. An example of this is the focus on a low carbon economy in the UK. However, the quality regimes in Australia and the UK utilise a relatively simple set of measures. These are illustrated in Table 2, along with a comparison against the revenue linked measures proposed by Transpower. In the case of Australia we have also shown both the initial version (Version 1) and the current (Version 4) of the STPIS.

57. Differences from Transpower's proposed output measures are highlighted in a dark orange colour. A more detailed version of this table is included in Appendix C.

[51] Australia has utilised incentive based regulation at a NEM level since 2007 (and within some States since 1994) and the UK have progressively introduced incentives since 1992.

Table 2 - International comparison

	Transpower's proposed Output Measures	Australia - STPIS Version 1	Australia – current (STPIS Version 4)	UK – RIIO
Grid Performance / Reliability	• GP1 – Number of unplanned outages ≥ 1 minute (#) • GP2 – Average duration of unplanned interruptions (mins) • GP3 – P90 duration of unplanned interruptions (mins) (±0.8% of MAR)	• **Loss of supply frequency (medium and large events threshold in system minutes)** • Average outage duration (in mins) • Circuit availability (%) **(±1% of MAR)**	• **Loss of supply frequency (medium and large event thresholds in system minutes)** • Average outage duration (USE events only - mins) • **Average circuit outage rate (# of unplanned outages due to faults)** **(±1% MAR)**	• **Energy not supplied (MWhs, incentive rate @£16,000)** **(-3% of MAR)**
Market Impact	• AP1 – Energy availability of HVDC circuits • AP2 – Availability of selected HVAC circuits (±0.2% of MAR)		• **Market Impact (# of instances with a marginal cost > $10/MWh)** **(+2% MAR)**	
Stakeholders				• **Customer satisfaction (±1% or MAR) and stakeholder engagement (+0.5% MAR)**
Asset related			• Proper equipment operation Reporting only Opex / Capex are subject to a benefit sharing through EBSS and CBSS	• Requirement to deliver NoMs Subject to a benefit sharing arrangement, subject to licence agreement provisions.
Investment incentives and Other			• Network Capability (innovation / growth incentive) (+1.5% MAR)	• Specific additional requirements around Safety, environmental and connections.

58. The primary differences between Transpower's proposal and the regimes in Australia and the UK are:

- The use of an energy not supplied, or an equivalent measure to signal the economic impact of an interruption (Australian V1 to V4 of the STPIS, UK). The UK utilise an incentive rate based on VoLL;
- The use of leading asset based measures (Circuit outage rate in Australia - V4 of the STPIS, and the requirement to deliver asset based Network Output Measures - NoMs in the UK);
- A direct measure on the market impact of asset outages (Australia);
- Customer satisfaction and stakeholder engagement (UK); and
- A comparatively higher total MAR reward / penalty in both Australia and the UK.

59. We also note that:

- Both Australia and the UK utilise Opex and Capex benefit sharing arrangements with consumers;

- Australia have recently introduced a reporting measure to indicate the frequency of mal-operation of protection equipment;
- The delivery of NoMs in the UK is a licence condition and if a Transmission Operator reaches its collar quality limit, then Ofgem have reopener provisions and can impose additional financial penalties on the company.[52]

60. Of particular relevance to the discussion in Section E above is Ofgem's rationale for the use of energy not supplied (ENS) as a measure. They state that ENS is readily measureable; controllable over the long term; and it can be consistently measured and compared. Ofgem view it as the best metric to use as it combines the frequency and duration of interruptions and the associated load that is affected. This provides a measure that reflects the ultimate output delivered to customers. As Ofgem (2011) notes:

    "An output based only on the number of interruptions does not provide any financial incentive for the TOs to restore supplies as quickly as possible, or to provide contingencies to allow rapid restoration."[53]

61. In regard to the market impact measure utilised in Australia, the AER note:

    "the AER's qualitative analysis of market outcomes concludes there has been a noticeable improvement in outage related market impacts, across all regions following take up of the MIC"[54]

62. The comparison between jurisdictions also suggests that that there is potential to move the regime in New Zealand towards that utilised in Australia and the UK, and a simplified structure consisting of five components:

    a. Supplier performance assessed against the economic impact of interruptions utilising energy not supplied or an equivalent measure;

    b. The direct monitoring of the market impact of asset outages to incentivise efficient decision making within maintenance and operational practices;

    c. A measurement of stakeholder satisfaction and engagement;

    d. Incorporation of leading asset related measures to signal future performance outcomes; and

    e. The requirement for an investment strategy targeted at delivering service levels agreed with customers by location utilising asset criticality, asset health and good asset management practices as a foundation.

63. Accordingly a review of the measures utilised internationally further supports submissions made by stakeholders on Transpower's proposal and our recommendations to encourage the further development of quality measures that signal both the economic impact of interruptions on customers and the market impact of asset outages.

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[52] Ofgem, "Decision on strategy for the next transmission price control - RIIO-T1" (31 March 2011), pg 26.
[53] Ofgem "Strategy for the next transmission price control – RIIO-T1 Outputs and incentives" (31 March 2011), p.36.
[54] AER, "STPIS Version 4 Final Decision" (December 2012).

64. The other significant observation in regard to Transpower's proposal is that the proposed revenue incentive is lower than utilised internationally. However, in our view, an initial revenue incentive of 1% is appropriate and in line with the starting incentive levels internationally. We note that internationally the revenue at risk has evolved over time. Version 1 of the STPIS utilised 1% for reliability. Version 2 of the STPIS introduced an additional +2% for the market impact measure. Under version 4 of the STPIS the incentives range from -1% to +3%.[55] The UK utilise a range of -4% to +1.5%.[56]

Specific differences in the measure parameters

65. As noted previously the detailed review of parameters for each of the proposed measures is being undertaken by the Commission, and therefore beyond the scope of this report. However, we do note there are some immediate and obvious differences between those utilised internationally and Transpower's proposal. We have recorded these here for completeness; however the Commission should consider these in more detail if they were to be applied to Transpower. We also note that within both the UK and Australia, specific parameters are applied to each individual company to reflect the specific circumstances faced.

66. The clear differences in the parameters we have observed are:

- We note that Transpower have proposed that interruption duration are capped at 24 hours. In Australia event durations are capped at 7 days; and
- We understand from Transpower it has not utilised a standard methodology for establishing the targets, caps and collars but rather included "what seemed appropriate." We note that the STPIS requires setting of the targets through the use of a sound methodology. While the methodology is regularly reviewed, we would recommend that the Commission establish some form of structured mechanism to ensure that the basis for the incentives is transparent to both Transpower and stakeholders.

The evolution of the regulatory frameworks internationally

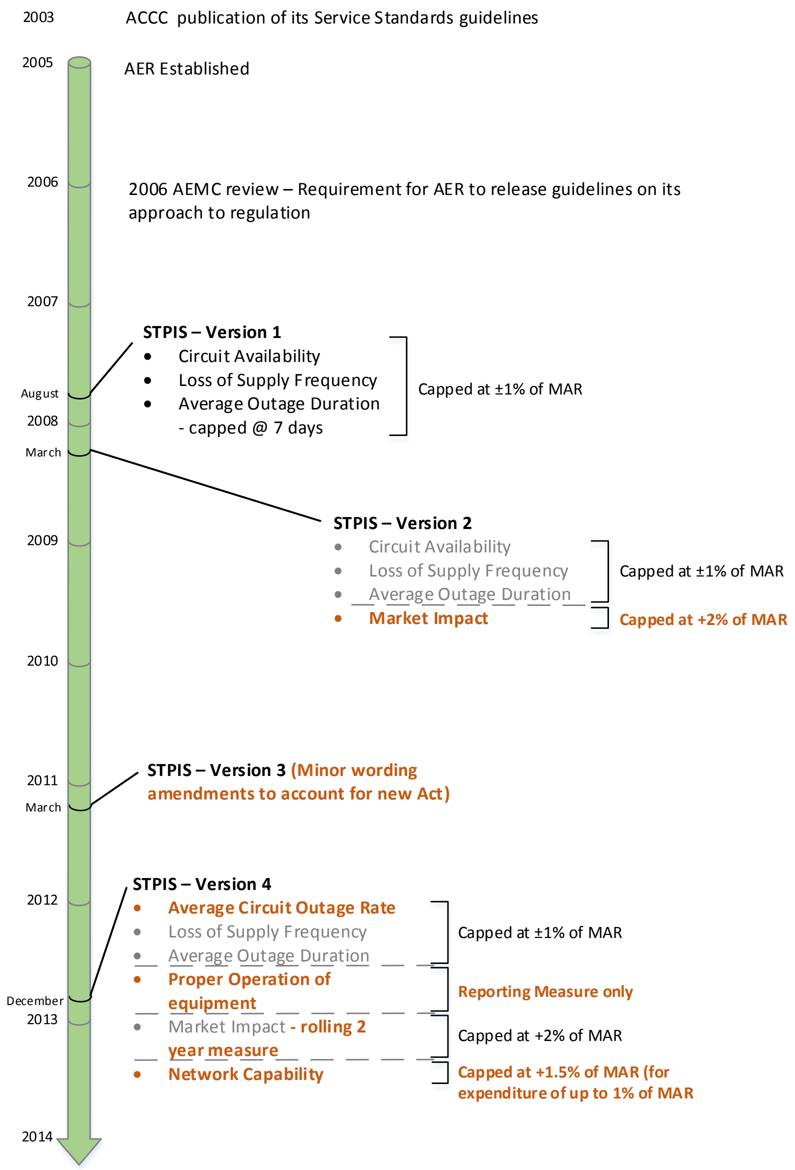
67. Transpower has indicated their intention to assess and develop the proposed measures during RCP2.[57] We would support and encourage this development. As a reference point it is useful to consider the transition path undertaken internationally.

68. It is our observation that over time regulators have moved to more specifically target the outcomes sought and tuned measure definitions to achieve this. In addition, regimes have been refined to remove any apparent overlaps between measures so as to minimise the doubling up of incentives. In our view, avoiding this duplication of incentives (either positive or negative) is

[55] excluding innovation or development related incentives.
[56] excluding innovation, development or safety related incentives.
[57] Transpower "Feedback on Stakeholder Submissions" (10 March 2014), pg 3.

an additional reason to directly measure and incentivise performance rather than rely on a composite of measures. By way of example only, Figure 2 below illustrates the transition that has occurred in Australia since 2007. The commentary in the bolded orange colour indicates the changes included in each update.

Figure 2 - Evolution of the national Australian transmission quality framework from 2007[58]



69. In addition to the targeting and fine tuning of measures, the incentives for innovation have featured more strongly in recent changes to regulated quality regimes.

70. Figure 2 illustrates that a relatively swift evolution of the Australian regime has occurred over a short period of time (2007 to 2012). We would therefore suggest that with only one Transmission company in New Zealand and a single level of regulatory governance, it should be

[58] The dates shown are the publication dates for each version of the STPIS. Application to each transmission company is dependent on the date in which its next RCP began.

possible to achieve a reasonable pace of development, particularly given that much of the information required to support the quality measures has been recorded and available (and in some instances reported on) for many years.

G. Conclusion

71. Having reviewed Transpower's engagement process and its proposal, in the light of the feedback received from submitters, along with a comparison to international practice our conclusion is that:

    a. Transpower's proposal is a good first step on the path of developing incentive measures that align with customer value;

    b. The engagement process undertaken was both appropriate and positively received by submitters;

    c. A number of development opportunities exist in regard to the measures utilised. We recommend that Transpower is encouraged to deliver these developments over the RCP2 period. These include:

        a. The development of measures that reflect the economic impact of interruptions and the market impact of equipment outages;

        b. Development of customer specific performance targets; and

        c. The continued development of investment strategy and linking of outputs sought by transmission customers to expenditure.

    d. The Commission should ensure, to the greatest extent practicable, Transpower is incentivised to complete the development activities ready for implementation in RCP3.

72. Our specific recommendations in regard to the conclusions from our review are described in Section B.

Appendix A – Measures proposed by Transpower

The following is a list of the Grid Output Measures proposed by Transpower. More detail can be found in Chapter 10 of Transpower's proposal. They are repeated here for reference only.

Grid Performance Measures:

- GP1 – Number of unplanned outages ≥ 1 minute
- GP2 – Average duration of unplanned outages
- GP3 – P90 duration of unplanned interruptions

Asset Performance Measures:

- AP1 – Energy availability of HVDC circuits
- AP2 – Availability of selected HVAC circuits

Other Measures:

- OM1 – Time to provide initial information following an unplanned interruption
- OM2 – Time to provide updated information following an unplanned interruption
- OM3 – Accuracy of notified restoration times following unplanned interruptions
- OM4 – Extent that we meet planned outage restoration times
- OM5 – Extent to which we place customers on 'N' security
- OM6 – Number of unplanned momentary (less than one minute duration) interruptions.

POS Categories established:

- High Priority
- Important
- Standard
- Generator
- N-Security

Appendix B – International regimes

Australia

Background to Transmission Regulation in Australia

Major electricity reforms have occurred in Australia over the last twenty years, commencing in the early 1990s. In 1991, the Industry Commission issued a report *Energy Generation and Distribution.*[59] The report found that the electricity industry was not performing to its full potential and that electricity had not been supplied to consumers at least cost due to poor investment decisions which resulted in excess capacity and gross overstaffing. Throughout the 1990s the structure of the industry changed with the disaggregation of wholly state-owned vertically integrated electricity monopolies resulting in the formation of competing generation and retailing entities and regulated transmission and distribution companies.

The Australian Competition and Consumer Commission (ACCC) was the industry regulator for electricity transmission network service providers (TNSPs). The Australian Energy Regulator (AER) was established in 2005 at which time it took over responsibility of regulating TNSPs in the National Electricity Market (NEM), in accordance with the National Electricity Rules (NER).[60] The current scope of the AER's regulatory authority includes price, quality, safety, reliability and security of supply. New South Wales (NSW), and Victoria were the first States to join the NEM. Queensland, South Australia, Australian Capital Territory (ACT) have progressively joined since then.

Regulatory Evolution

After a review of the regulatory framework for TNSPs in 2006 by the Australian Energy Market Commission (AEMC), it became a statutory requirement for the AER to establish and publish a Service Target Performance Incentive Scheme (STPIS) to encourage TNSPs to improve or maintain a high level of service for the benefit of participants in the NEM and end users of electricity. The design of the STPIS was based on the service standards guidelines which were developed by the ACCC in 2003. Since its implementation, the AER has progressively developed the STPIS with the latest being Version 4.

The initial scheme (Version 1), which was published on 31 August 2007 consisted of a single service component focused on network availability and reliability. It provided incentives for TNSPs to improve their performance by financially rewarding or penalising the companies when delivered performance was respectively better or worse than specified targets. The objective was to balance the incentives on TNSPs to reduce expenditure, which could result in reduced service quality, and the need to maintain and improve reliability for customers. The total revenue at risk under the service component was set at 1% of a TNSPs maximum allowed revenue (MAR) for the relevant calendar year. A TNSP's revenue in the following regulatory control year was then adjusted by the

[59] Industry Commission (1991), *Energy Generation and Distribution Volume 1,* Commonwealth Government Printer, Canberra, p.1

[60] Western Australia and Northern Territories transmission networks are outside of the AER jurisdiction

financial bonus or penalty accrued under the scheme. The service component of Version 1 linked regulated revenues to the TNSPs' performance against the three parameters that were previously used under the ACCC's service standards guidelines. Version 1 parameters were:

- Transmission circuit availability. This parameter acted as a lead indicator of reliability and incentivised TNSPs to maintain and improve availability of assets.
- Loss of supply event frequency. The purpose of this parameter was to incentivise TNSPs to minimise loss of supply events caused by unplanned outages. It was based on the number of events that breached a specified level of system minutes. Unplanned outages of less than one minute were excluded. The AER's rationale for this was that if outages less than one minute were included, it may result in all users paying for performance improvements that relatively few users would require.[61]
- Average outage duration.[62] This parameter incentivised TNSPs to reduce the average length of all unplanned outages. All unplanned outages over 1 minute were included. However, the duration of outages were capped at seven days.

Performance for each parameter under the service component was measured by comparing a TNSP's performance during the year against the targets, caps and collars set in its transmission determination. The TNSP had to propose the weightings for each parameter in its revenue proposal to the AER. The proposed weightings had to be consistent with the STPIS objectives.

Under Version 1 of the STPIS, TNSPs were permitted to exclude events outside of the TNSPs control. These were classified to be:

- Outages resolved in less than one minute;
- Force majeure events such as bush fires, acts of war, government intervention and third party events that cause an outage on the transmission system.

While the details of some of the service component parameters have changed, the 1% incentive cap for the service component has remained since the inception of the STPIS. A number of additional financial incentives have subsequently been incorporated.

At the time of implementing the STPIS in 2007 the AER concurrently developed a performance incentive scheme based on the market impact of transmission congestion (MITC), with a view of incorporating the MITC into the STPIS. By incorporating this market impact component (MIC) into the STPIS incentives were provided for TNSPs to minimise the market impact of outages.[63] As noted by the AER, the MITC encourages "TNSPs to consider how customers value their actions and how their operational decisions may affect market outcomes. Under the MIC, TNSPs are encouraged to improve the availability, security and ultimately reliability of the transmission system at the times

[61] AER, "Final Decision – Electricity transmission network service providers: Service Target Performance Incentive Scheme" (August 2007), p. 7
[62] AER, "Final Decision – Electricity transmission network service providers: Service Target Performance Incentive Scheme" (December 2012), p.4
[63] AER, "Final Decision – Electricity transmission network service providers: Service Target Performance Incentive Scheme (incorporating incentives based on the market impact of transmission congestion)" (March 2008), p.12

most valued by transmission network users.[64] In March 2008, Version 2 of the STPIS was published incorporating the incentives based on the MITC. The MITC is a bonus only scheme, providing TNSPs with an opportunity to receive a bonus of up to 2% of MAR, if a TNSP removes all outage constraints with a marginal value greater than $10/MWh. Targets were based on a TNSP's average historical performance. As previously stated, the total revenue at risk under the service component remained unchanged at 1% of MAR.

In August 2010 Powerlink proposed amendments to the STPIS. The AER then consulted on Powerlink's proposal as required by the NER and subsequently Version 3 of the STPIS was published in March 2011. The amendments generally related to parameters and definitions specific to Powerlink. However there were some minor amendments that applied to all TNSPs. No parameters were added or deleted.

In October 2011 the AER commenced a comprehensive review of the STPIS, to ascertain if changes were needed to further incentivise TNSPs to maintain and improve the performance of their networks. The AER requested input to the review from major users, generators, the Australian Energy Market Operator (AEMO) and TNSPs. Following the review, significant amendments were made to the STPIS. The AER's objectives were to ensure that TNSPs maintained high levels of reliability, manage their network to reduce the impact of outages on wholesale spot market prices and promote innovation by TNSPs to deliver enhanced services through low cost alterations to their network. The changes were:

- Service component - The service component was amended to focus more on lead indicators of reliability and to bring greater standardisation between TNSPs on definitions, exclusions and weightings. A 'proper operation of equipment' parameter was introduced to measure the number of times that protection and control equipment fails to operate correctly. This is a reporting only measure. However the AER note that the effectiveness will be assessed in later reviews and a financial incentive will be added if deemed necessary. The 'transmission circuit availability' parameter was renamed to 'average circuit outage rate.' The parameter itself was also changed to report on outages caused by unplanned events. The AER's rationale for this was to reduce the overlap with the MIC and to focus the parameter on outages that act as a lead indicator of potential reliability;
- MIC - This component was changed to measure performance on a rolling two calendar year basis compared to a target of the previous three calendar year average outcomes. This amendment was made to improve consistency of performance, incentivise TNSPs to provide continual improvement on performance, reduce perverse outcomes and reduce the potential of gaming; and
- Network capability component - This component was introduced to incentivise a TNSP to manage its network assets to develop and complete one off projects, up to a total of 1 per cent of the MAR for the year, that improve the capability of the transmission network at times most needed. The incentive rate is 1.5 per cent of MAR. AEMO is involved in prioritising projects so as to deliver value for money for consumers.

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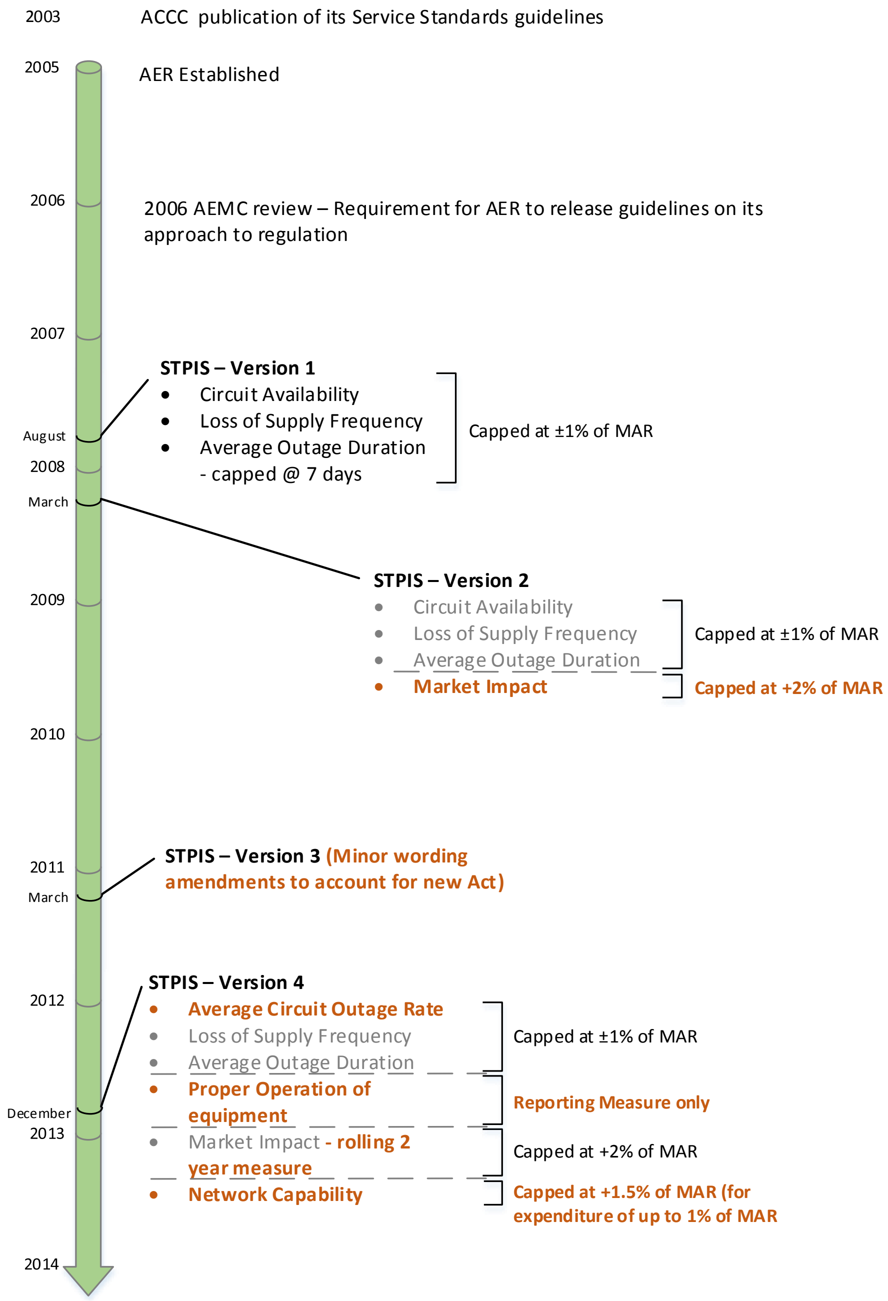
[64] AER, "Final Decision – Electricity transmission network service providers: Service Target Performance Incentive Scheme (incorporating incentives based on the market impact of transmission congestion)" (March 2008), p.4

Figure 3 – Australian STPIS Evolution path



United Kingdom

Background

The electricity industry in the UK was privatised in 1989. Today, there are three regional Transmission Operators (TOs); National Grid Electricity Transmission[65] (NGET), Scottish Hydro Electricity Transmission Ltd[66] (SHETL) and Scottish Power Transmission Ltd[67] (SPTL). The system as a whole is operated by a single System Operator (SO), with this role performed by NGET. The industry is regulated by the Office of Gas and Electricity Markets (Ofgem). Each TO operates under licence from Ofgem. The licence incorporates the price control contract that outlines what the TO is expected to deliver; constraints on the revenue that can be earned from customers and the provision of timely, accurate and consistent information.[68]

Evolution of the Regulatory Arrangements

Incentive-based regulation was introduced after privatisation in 1992, with the regulator implementing a RPI-X model framework. When initially introduced, the main objective was to provide TOs with incentives for efficiency. The RPI-X framework allowed TOs to retain financial benefits if they outperformed their allowed ex-ante revenue calculation. However, should a TO underperform, the cost of the underperformance was shared between the TO and consumers. The intention of the framework was also to support competition and innovation.

Overtime, the regulatory framework has evolved and expanded on the initial efficiency incentives to encourage TOs to act in a way that benefits consumers. Additional incentives were added to reflect expected efficiency improvements, capital investment requirements and rewards or penalties for service performance. As such, the X-Factor was augmented to include reliability incentives, environmental incentives and incentives for timely delivery.[69] Pension allowances[70] were also introduced.

Since privatisation there have been five regulatory price control periods (including the current period). Initially, the price control periods were different for each TO. However in 2003, Ofgem made the decision to align the price control periods in order to have consistency with the treatment of common costs and incentive arrangements. To facilitate this, extensions to some of the TOs' price control periods were implemented. TPCR4, for the period 1 April 2007 to 31 March 2012, was the first aligned price control period.

In 2005 (midway through TPCR3) the electricity transmission network reliability incentive scheme was introduced to further strengthen TOs incentives to maintain and improve reliability and

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[65] Which owns the network in England and Wales.
[66] Which owns the northern Scotland network.
[67] Which owns the southern Scotland network.
[68] Jenkins, Cloda., "RIIO Economics: Examining the economics underlying Ofgem's new regulatory framework.", Working paper, June 2011.
[69] Jenkins, Cloda, "RIIO Economics: Examining the economics underlying Ofgem's new regulatory framework.", Working paper, June 2011.
[70] In TPCR4 changes were made to give extra protection for TOs in relation to funding defined benefit pension schemes.

continuity of supply in order to reduce disruption to consumers.[71] Under the incentive scheme TOs are measured against a target level of performance based on the amount of energy unsupplied in which they are either rewarded or penalised depending on whether they performed below or above a target. The target level differed for each TO. The incentive was kept in the TPCR4 regulatory control period.

Overtime, concerns with the RPI-X regulatory framework started to arise. These concerns included a lack of innovation within the industry in order to meet the government's directive for a low carbon sector; the needs of the customer were given little attention; the design of the various incentive mechanisms resulted in perverse incentives at times; and the additional incentives that were added overtime resulted in the RPI-X framework becoming complicated.

Consequently, in 2008, Ofgem undertook a detailed review of its entire energy network regulation to ascertain if the regulatory framework was 'fit for purpose' to enable energy network companies to meet the challenge of delivering a sustainable, low carbon energy sector whilst delivering value for money for existing and future consumers. The review was entitled the RPI-X@20 review. After extensive consultation and analysis, Ofgem in 2010 concluded the RPI-X@20 review and announced that it was introducing a new regulatory framework for energy network companies, known as RIIO (Revenue = Incentives + Innovation + Outputs). Under RIIO, the regulatory control period was extended to eight years for energy network operators. The first control period for TOs is known as RII0-T1 and is for the period 1 April 2013 through to 31 March 2021.[72]

The rationale for the design of RIIO was to encourage all energy network operators to:[73]

- Put customers and stakeholders at the heart of their decision-making process;
- Invest efficiently to ensure continued safe and reliable services;
- Innovate to reduce network costs for current and future consumers; and
- Play a full role in delivering a low carbon economy and wider environmental objectives.

Under RIIO, energy network operators are to submit to Ofgem well-justified business plans detailing how they intend to meet the RIIO framework objectives. TOs that submit a high quality, and well-justified business plan can have their business plans proposals fast-tracked by Ofgem. If a TO's proposal is fast-tracked, that TO will receive their final proposal approximately a year ahead of the implementation of the price control. The RIIO framework places a strong emphasis on stakeholder engagement. Accordingly, TOs are required to obtain stakeholder input into their business plans and also illustrate how this input has been used to develop the plans. TOs propose their own outputs in their plans. Outputs are to be listed under six key output categories:[74]

1. **Customer satisfaction**
   - There are two components under the customer satisfaction output. The first component under RIIO-T1 is for network companies to develop and refine a robust

[71] Ofgem "Regulating Energy Networks for the Future: RPI-X@20 History of Energy Network Regulation" (27 February 2009), p.55
[72] TPCR4 was extended/rolled over for one year to 31 March 2013 in order to implement RIIO-T1
[73] Ofgem "RIIO: A new way to regulate energy networks, Final decision" (October 2010)
[74] Ofgem "Decision on strategy for the next transmission price control – RIIO-T1" (31 March 2011) p.21

customer/stakeholder satisfaction survey. A symmetrical financial incentive of ±1% of annual allowed revenue is attached to the development of the survey. The second component under the customer satisfaction output is the stakeholder engagement reward. This is a discretionary reward for TOs that can demonstrate that their effective stakeholder engagement has delivered exceptionally positive outcomes for customers. The reward is worth up to a maximum of 0.5% of annual allowed revenue.

2. **Safety**
   - TOs are required to comply with their legal safety obligations, which are set out in legislation and monitored by the Health and Safety Executive. This output is measureable (a TO is either compliant or not) and comparable (all TOs are subject to the same legislation).

3. **Reliability**
   - The primary output for this category is energy not supplied (ENS). The incentive rate is £16,000/MWh which is based on an estimate of VoLL. A collar for all TOs has been applied by Ofgem limiting the maximum penalty to 3% of allowed revenues. TOs are required to propose secondary deliverables in their proposal. For example NGET has an output under this category to include measures regarding asset health, asset condition and criticality with agreed targets. Under this category NGET has set a penalty/reward of 2.5% of the value of any over/under of network replacement outputs.[75]

4. **Connections**
   - TOs are required to meet the existing legal requirements; which has a general enforcement policy.

5. **Environmental impact**
   - TOs are required to contribute to the UK's broader energy and environmental objectives by reducing the visual impact of their networks, reducing greenhouse emissions, reducing the visual impact of their networks and reducing their carbon footprint. The environmental category includes reputational and financial incentives, which are explained further on in this document.

6. **Social obligations.**
   - Ofgem did not impose any social obligations on TOs. The rationale for this was that at the time of implementing RIIO, TOs were not subject to any social obligations and Ofgem did not see the need to introduce new obligations.

[75] Ofgem "RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas" (17 December 2012), p.22

In addition to the output categories, secondary deliverables relating to the outputs were instigated in order to ensure that TOs can deliver in the future control periods. This was initiated to ensure that investment is done in an efficient way that meets the Government's environmental objectives.[76]

As mentioned above, the primary output measure of reliability for TOs is ENS. Ofgem's rationale for this is that ENS is readily measureable; controllable over the long term; and it can be consistently measured and compared. Ofgem view ENS as the best metric to use as it combines the frequency and duration of interruptions and the associated load that is affected. This provides a measure that reflects the ultimate output delivered to customers. As Ofgem (2011) notes "An output based only on the number of interruptions does not provide any financial incentive for the TOs to restore supplies as quickly as possible, or to provide contingencies to allow rapid restoration."[77]

For the RIIO-T1 price control review, Ofgem have considered the value of £16,000 to be a reasonable value placed on ENS, by TOs when they developed their business plans.[78] Ofgem have applied a common collar across all TOs limiting the maximum penalty to 3% of allowed revenue. Additionally a minimum standard of performance is stipulated in each TO's condition of licence. If a TO's quality performance degrades to the point where they breach the minimum standard they have to demonstrate that they have taken all reasonable measures both before and after the loss of supply events to minimise unsupplied energy. If it is considered that the TO has not done this, Ofgem has the option to commence licence investigation procedures along with the potential to apply a financial penalty.[79]

There are ENS events that are excluded when calculating ENS.[80] These are:

- Events lasting three minutes or less;[81]
- Events relating to customers with a lower standard of connection will be excluded;
- Any unsupplied energy resulting from a user's request for disconnection in accordance with the Grid Code;
- Any unsupplied energy resulting from a de-energisation or disconnection of a user's equipment necessary to ensure compliance with an instruction by the SO;
- User's equipment necessary to ensure compliance with an instruction by the SO to the licensee pursuant to the STC; and
- Any unsupplied energy resulting from a shortage of available generation.

It is important to note that events relating to planned outages are not excluded when calculating ENS. Events relating to emergency de-energisation, third party damage, extreme weather and exceptional events will not be automatically excluded.

The RIIO framework not only places financial incentives on TOs but it also holds TOs accountable through their licence for the delivery of the outputs detailed in their business plan for the control

[76] Ofgem: Decision on strategy for the next transmission price control – RIIO-T1, 31 March 2011, p.21
[77] Ofgem: Strategy for the next transmission price control – RIIO-T1 Outputs and incentives, 31 March 2011, p.36
[78] Ofgem: Decision on strategy for the next transmission price control – RIIO-T1, 31 March 2011, p. 26
[79] Ofgem : Decision on strategy for the next transmission price control – RIIO-T1, 31 March 2011, p. 26
[80] Ofgem: Strategy for the next transmission price control–RIIO-T1 Outputs and incentives, 31 March 2011, p.37
[81] These events relate to the correct operation of delayed auto-reclose which could be assumed to cover events for which the cause is weather.

period. Ofgem is able to take enforcement action against a TO for significant underperformance on output delivery. Ofgem can adjust revenues or allowances downwards due to underperformance.

Under the RIIO framework it is not possible to set the actual level of annual allowed revenue for a TO due to the implementation of uncertainty mechanisms to manage volatility during the price control. These mechanisms include revenue drivers, volume drivers, specific re-openers and pass-through items.[82] An example of an uncertainty mechanism is the Efficiency Incentive Rate (EIR). The EIR incentivises TOs to restrain or reduce costs of delivering its outputs during the price control period.[83] The rate of the EIR is set at a range of 40-50%. As such, a TO is able to retain between 40% and 50% of any cost savings. The EIR is symmetrical, so should a TO over spend it is responsible for the overspend at the percentage that the EIR is set at for that TO.

The RIIO framework also aims to encourage TOs to be innovative to meet the challenges of an aging network and the government's directive for the industry to be a low carbon energy sector.[84] Incentives were introduced to make networks smarter and to accelerate the development of a low carbon energy sector that will deliver financial benefits to consumers:

- The scope of the Network Innovation Competition (NIC) stimulus fund was extended to include projects which meet environmental objectives. The maximum level of funding under the NIC was increased up to 90% of the cost of the project.
- The Electricity Network Innovation Allowance (NIA) was introduced. The NIA is a set allowance to provide limited funding for small projects that have the potential to deliver financial benefits to the TO and their customers.[85] The allowance will be set between 0.5% and 1% of allowed revenue.[86] A limit on the total level of funding was set at £30m pa.
- An allowance per TO was introduced to reduce the visual impact of existing infrastructure. The allowance is based on willingness to pay (WTP) analysis conducted by TOs. A reputational incentive was introduced to promote low carbon flows.[87]

Customer/stakeholder satisfaction is a key component of the RIIO framework. Ofgem noted the importance of each TO having a robust customer/stakeholder survey. Hence the decision to incentivise TOs to develop and refine their surveys under RIIO-T1 control period. Ofgem has advised the survey must:[88]

- capture all relevant customers
- contain appropriate questions
- have been adequately tested, such that a credible output level can be set
- be appropriately weighted across customer types and questions (if need be).

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82 Ofgem, "Decision on strategy for the next transmission price control – RIIO-T1" (31 March 2011), p. 38

83 Ofgem "RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas" (17 December 2012), p. 45

84 https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation

85 https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation/electricity-network-innovation-allowance

86 Ofgem "Decision on strategy for the next transmission price control – RIIO-T1" (31 March 2011), p.45

87 Ofgem "Decision on strategy for the next transmission price control – RIIO-T1" (31 March 2011), p .7

88 Ofgem "Strategy for the next transmission price control – RIIO-T1 Outputs and incentives" (31 March 2011), p.36

Once the surveys have been fully developed and trialled Ofgem will determine the precise weightings between absolute performance over the course of the price control and the improvement or deterioration in performance compared to previous years.

Appendix C – Detailed comparison

	Transpower Proposal	Australia (Version 4 STPIS - December 2012)	UK
Grid Performance /Reliability	• GP1: Number of unplanned interruptions >1min caused by faults in TP network. • GP2: Average duration of unplanned interruptions. • GP3: P90 unplanned interruption duration, which reflects the duration of our longer interruptions. Targets vary by customer category and incorporate extreme events, weather etc. Proposed +/- 0.8% at risk	• Loss of supply event frequency (number that breach system minute thresholds – split into moderate and large events) • Average outage duration (unplanned outages whether or not there is a loss of supply, based on time to restore plant) • Average circuit outage rate (number of unplanned outages caused by faults - impact is measured by the MIC) • Proper operation of equipment (number of instances where protection or control system failures or incorrect isolation during maintenance) – for reporting only This service component has an incentive of +/- 1% of MAR.	• Varies by transmission company. • Up to a 3% collar for Energy Not Supplied @ approx £16,000 per MWh. If a TO triggers the floor they will be required to take all reasonable steps to minimise the unsupplied energy. This a minimum standard of performance managed through a licence condition. Ofgem can also adjust revenue downwards if outputs are not delivered.
Asset performance	• AP1: Energy availability of HVDC circuits • AP2: Availability of selected HVAC circuits Proposed +/- 0.2% at risk		• Requirement to deliver on network output measures or NoMs targets. NoMs relate to criticality, replacement priorities (or risk), system unavailability, average circuit unreliability (ACU), faults and failures. If either under or over delivered Ofgem will initiate the second tier assessment process. Revenue in next reset is adjusted accordingly. Incentive is +/- 2.5% of the value of the additional or avoided costs.
Information Measures	• OM1 - OM6, No $ at risk		
Market Impact	(refer to asset performance measures above)	• +2% of MAR. This component rewards TNSPs for reducing the market impact of planned outages by measuring the number of dispatch intervals that result in > $10/MWh. Change to a rolling two calendar year basis compared to the average impact over the previous three calendar years.	
Network Capability		• Network Capability +1.5% on completion of projects (expenditure capped at 1% of MAR) - subject to completion of projects that improve the capability of the transmission network at times most needed.	
Safety			• Statutory requirements. Note link to NoMs

Environmental			• Subject to a reward/penalty based on the non-traded carbon price for carbon price for carbon equivalent emissions. Covers visual amenity and transmission losses.
Customer Satisfaction			• Annual customer survey and discretionary reward for stakeholder engagement of +/- 1% and discretionary bonus of +0.5% of allowed revenue
Connections			• Have enforcement obligations to meet existing legal requirements for connections