

Issues paper—options for ensuring efficient reactive power investment

Prepared by the Electricity Commission

26 September 2008

Executive Summary

Introduction

In response to a number of concerns electricity industry participants have expressed in relation to the power factor requirements in the Connection Code, the Commission is exploring what options are available to address those concerns.

The purpose of the Connection Code is to set out the technical requirements and standards that designated transmission customers must meet in order to be connected to the grid and with which Transpower (in its capacity as grid owner) must also comply. The Connection Code forms part of the default transmission agreement (Benchmark Agreement). Enforcement of any provisions in the Connection Code is a bilateral matter between Transpower and the designated transmission customer.

The Commission has no fixed view about whether change is required to the power factor requirements in the Connection Code or, if so, which of the options is the most appropriate (or whether there is a better option). At this stage, the Commission is seeking feedback from the interested participants so that it is better informed to form a view on its preferred option.

Following consideration of submissions, the Commission intends to develop a preferred option and consult on it and the reasonably practicable alternatives.

Purpose of this report

The purpose of this paper is to provide interested parties with background material on:

- the regulatory framework;
- criticisms of the current requirements, including:
 - what the Commission sees as the “problem” that needs to be resolved;
 - the process for the development of the current Connection Code and in particular the power factor requirement;
 - assessment of costs and benefits that underpinned the decisions to approve the power factor requirement;
 - measurement issues;
 - integration issues with part C of the Electricity Governance Rules 2003;
- the options analysed, including:
 - the characteristics of the supply and demand for reactive power;
 - the framework applied to assess the options; and

- a summary of the assessment of the options,

and to seek submissions on the options and specifically responses to the Commission's questions.

Submissions

The Commission invites submissions on the questions in this paper and any other matters submitters wish to comment on by 5pm on 24 October 2008. Please note that submissions received after this date may not be considered.

The Commission requests that submissions are provided in electronic format (Microsoft Word). The electronic version should be emailed with "Consultation on Issues Paper – Options for efficient reactive power supply" in the subject header to: info@electricitycommission.govt.nz.

Any queries should be directed to:

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The Commission will acknowledge receipt of all submissions electronically. Please contact Maree McGregor if you do not receive electronic acknowledgement of your submission within two business days of sending your submission.

Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. All information provided to the Commission is subject to the Official Information Act 1982.

Glossary of abbreviations and terms

In this paper, unless the context requires otherwise:

Act means the Electricity Act 1992.

AOPOs means asset owner performance obligations as set out in section III of part C of the Rules.

BA means the benchmark transmission agreement set out in schedule F2 of part F of the Rules.

Commission means the Electricity Commission.

Commission's PF Proposal means the reasonably practicable alternative the Commission proposed in the Original Consultation Paper that the minimum PF in clause 4.4 of the [draft] Connection Code be substituted for an alternative value of between 0.95 and 1.0 at peak times in the case of the UNI and USI Regions.

Connection Code means the connection code that is set out as schedule 8 to the BA.

DTC means a designated transmission customer.

GIT means the grid investment test set out in schedule F4 of part F of the Rules.

GRS means the grid reliability standards set out in schedule F3 of part F of the Rules.

GUIRP means the grid upgrade investment review policy, published in June 2008 designed to promote an effective process for both the preparation of investment proposals by Transpower, as part of Transpower's wider grid planning process and the review and approval or rejection of those proposals by the Commission.

GUP means a grid upgrade plan submitted by Transpower to the Commission under section III of part F of the Rules.

GXP means grid exit point.

LNI means the Lower North Island region.

Original Consultation Paper means the Commission's consultation paper of 19 October 2007 entitled "*Proposed Connection Code and Outage Protocol*".

PF means power factor.

PPOs means the system operator's principal performance obligations set out in section II of part C of the Rules.

Rules means the Electricity Governance Rules 2003.

SO means the system operator, Transpower.

SVC means Static VAR compensator.

TA means a transmission agreement between Transpower and a DTC.

TPM means the transmission pricing methodology set out in schedule F4 of part F of the Rules.

Transpower means Transpower New Zealand Limited.

Transpower's PF Proposal means Transpower's proposal in the Original Consultation Paper that the PF at any point of service be not less than 0.95 lagging at peak times.

UNI means the Upper North Island region.

USI means the Upper South Island region.

Table of Contents

Executive Summary	1
Introduction	1
Purpose of this report	1
Submissions	2
Glossary of abbreviations and terms	3
Table of Contents	5
1. Introduction	7
2. Regulatory framework	8
3. Criticism of current requirements	9
3.1 Introduction	9
3.2 Problem being addressed	9
3.3 Process	11
3.4 Assessment of costs and benefits	12
3.5 Measurement Problems	15
3.6 Part C integration issues and unity power factor system operability issues	19
4. Option Analysis	24
4.1 Introduction	24
4.2 Characteristics of the supply and demand for reactive power	24
4.3 Assessment Framework	26
4.4 Options	27
4.5 Connection Code option (the status quo)	28
4.6 The market option	33
4.7 Administered (peak Mvar) charge option	36
4.8 The no obligation option	39
4.9 Assessment Summary	40
5. Process and timetable	41
Appendix 1 – List of Questions	44

1. Introduction

- 1.1.1 Consultation on the power factor (**PF**) issue is in response to industry concerns about the practicality and cost of meeting the PF requirements in the Connection Code.
- 1.1.2 These requirements effectively require that reactive power offtake in the Upper North Island (**UNI**) and Upper South Island (**USI**) regions by designated transmission customers (**DTCs**) is zero during peak demand periods.
- 1.1.3 The focus of this paper is on the exploration of a range of options to encourage the efficient supply of reactive power. There are a number of complex issues involved with each of the options and the Commission is initially seeking submissions on what can be practically achieved under each of them. Following analysis of submissions and industry views, the Commission proposes to form a view on its preferred option and what the reasonably practicable alternatives are and will undertake further consultation on these before implementing a solution.
- 1.1.4 This paper does not consider in detail the issues around reactive power reserve currently purchased by the system operator (**SO**). However, it does discuss integration issues with part C of the Rules¹ and the system operation issues in section 3.6.
- 1.1.5 The options discussed below are concerned with the provision of a base level of reactive power supply rather than the issues surrounding the provision of short-term dynamic support. Dynamic support is required largely to manage contingent events such as the sudden forced outage of heavily loaded transmission lines, other transmission equipment or generators. Investment in substantial dynamic reactive power support devices has been approved by the Commission in recent years and in some areas (UNI and USI) this is expected to continue. While this need is caused both by the characteristics of the transmission system and the dynamic characteristics of demand (large motors), at this stage it would not be reasonable or efficient to attempt to require provision of this from grid off-take customers.
- 1.1.6 Therefore the primary objective of this paper, and the proposed consultation, is to seek direction in developing a mechanism that will encourage efficient long-term investment in “static” reactive power equipment. It is however implicit that this static requirement is defined at periods of peak demand when the transmission system is heavily utilised.

¹ Rule 3.3.4.2 requires the Connection Code to give effect to the desirability of the Connection Code and part C operating in an integrated and consistent manner where possible.

2. Regulatory framework

- 2.1.1 DTCs are generators, distributors and directly-connected customers, all of whom are required by rule 3.1.1 of section II of part F of the Electricity Governance Rules 2003 (**Rules**)² to have a transmission agreement (**TA**) with Transpower.
- 2.1.2 The Benchmark Agreement (**BA**) set out in schedule F2 of section II of part F of the Rules applies as a default TA between Transpower and each DTC if the parties have been unable to agree a TA. Importantly, any negotiated TA must be materially consistent with the BA.
- 2.1.3 The Connection Code sets out the default technical requirements and standards that DTCs must meet in order to be connected to the grid and that Transpower must comply with. It is set out as schedule 8 to the BA and cannot be varied for individual DTCs, even if they have a negotiated TA. Transpower and DTCs are required to comply with the Connection Code under rules 3.1.3 or 3.1.6 (see rule 3.3.1).
- 2.1.4 The Connection Code requires, *inter alia*, that DTCs in the Upper North Island (**UNI**) and Upper South Island (**USI**) regions maintain unity PF at peak times when drawing power off the grid from 1 April 2010. The relevant clause in the Connection Code is:

4.4 Minimum power factor:

- (a) *The Customer must ensure that its Equipment does not unreasonably draw on the reactive power sources of the **grid** during each regional peak demand period. If **electricity** is being drawn off the **grid** the Power Factor at any Point of Service the Customer must:*

...

- (2) *from 1 April 2010, in the case of demand, maintain a Power Factor of not less than:*

(i) *1.0 (unity) at each relevant Point of Service during each relevant regional peak demand period in the Upper North Island Region and the Upper South Island Region; and*

(ii) *0.95 lagging at each relevant Point of Service during each relevant regional peak demand period in the Lower North Island Region and the Lower South Island Region.*

- 2.1.5 If DTCs are unable to meet the obligation or if there will be a delay in meeting the obligation, they can negotiate with Transpower to enter into a non-compliance or “equivalence” agreement in accordance with the process set out in Appendix A of the Connection Code. The DTCs could negotiate a TA which provided, for example, for Transpower to invest to ensure that the obligation was met.

² References in this Issues Paper to Rules are to rules in section II of part F of the Rules unless the context requires otherwise.

3. Criticism of current requirements

3.1 Introduction

3.1.1 The Commission has received a number of criticisms from the industry in relation to the PF requirements, focusing on the following five issues:

- (a) a lack of clarity about what problem is being addressed by the PF requirement;
- (b) the process that led to the finalisation of the PF requirement in the Connection Code;
- (c) a lack of specificity about the costs and benefits of the PF requirement;
- (d) the practicality and cost of measuring conformity with the PF requirement; and
- (e) integration with part C and system operation.

3.2 Problem being addressed

3.2.1 Whenever PF at the connection point is less than unity, and lagging, the transmission network is supplying reactive power to the distribution network. This reactive power demand is created inside the distribution network by the configuration of the distribution assets and end-consumer loads.

3.2.2 When the transmission grid capacity is likely in the future to be constrained through lack of local sources of reactive power to provide voltage support, the PF requirements in the Connection Code will lead to greater efficiency in investment decision-making than a lower PF, since it will mean that connected parties face the costs of taking supply at a lower PF (i.e. consuming reactive power provided by the transmission grid) directly, consistent with the causer pays principle.³

3.2.3 Some lines businesses may need to invest in new equipment to meet this requirement. For this reason a two-year transition period was instigated before this requirement would apply, which at least would allow time to negotiate non-compliance or equivalence agreements.

3.2.4 The intention of the inclusion of minimum PF requirements in the Connection Code was to allow connection customers to choose between:

- (a) investing in voltage support equipment in their own networks to reduce losses and improve voltage performance; or
- (b) contracting with Transpower to provide voltage support services to the customer, either:

³ The causer pays principle is supported by cost-reflectivity principles and dynamic efficiency considerations, in that those parties whose actions lead to costs being incurred are responsible for meeting those costs. "Causer pays" in this instance means those parties creating the requirement for reactive power to be provided for by the grid pay for its provision, and/or provide mitigation, reducing the amount of reactive power sourced from the grid.

- (i) as part of a non-compliance arrangement, as provided for in Appendix A of the Connection Code in the short term; or
- (ii) by, for example, agreeing to pay Transpower to invest in sources of reactive power, in the longer term.

3.2.5 The PF obligations on the DTC were designed to ensure that off-take customers meet the cost of the services required and that reactive power off-takes at grid exit points (**GXP**s) do not inefficiently restrict the capacity of the transmission grid in potentially voltage constrained regions.

3.2.6 However, this intention may not be achieved because:

- (a) if the DTC does not invest in new equipment in order to meet the minimum PF requirements, and Transpower does not enforce these obligations under the TA (which is a bilateral agreement between Transpower and DTCs so cannot be enforced by anyone else), the result could be that the GRS would not be met at the relevant GXP;
- (b) Transpower might then apply to the Commission under section III of part F of the Rules for approval of investments in voltage support equipment at the GXP, either as a standalone investment or as part of a larger investment;
- (c) under the transmission pricing methodology (**TPM**), voltage support equipment at a GXP that is for grid voltage support purposes is classified as an interconnection asset unless it has been installed at a DTC's request. Most voltage support equipment at a GXP can be used both to meet the reactive power demands of DTCs and for grid support purposes; and
- (d) therefore, there is an issue whether, if the Commission were to approve an investment by Transpower in voltage support equipment⁴, the costs of such equipment would be spread across all DTCs (if an interconnection asset), or charged only to the DTC taking the reactive power supply (if a connection asset).

3.2.7 The Commission is conscious that assets may be connection assets at one time and interconnection assets at another. On balance, the Commission considers that given that the primary performance characteristics of transmission assets (and the transmission grid) are their maximum transfer capacity and reliability, the purpose of the investment should be determined at the time the charges are fixed under the TPM, i.e. at the regional coincident peak. If the net reactive power flow during that half-hour period at the relevant GXP is out of the grid, the purpose of the investment would be considered to be reactive power supply rather than grid support, and thus the investment would be considered a connection asset.

⁴ In accordance with the rules in section III of part F of the Rules, the proposal would need to be compared with a number of alternative projects in order to pass the GIT before the Commission can approve it. It may be that an alternative is to make no investment at all (in the case of an investment proposal only for voltage support equipment) or to make an investment without the voltage support equipment (in the case of a larger investment proposal).

Q1. Do you agree that it is reasonable to decide the purpose of an investment at the time the charges are fixed under the TPM?

3.3 Process

3.3.1 The process that led to the finalisation of the Connection Code, including the PF requirement, was undertaken in second half of 2007, culminating in a recommendation to the Minister in December 2007 to include the Connection Code in the Rules.

3.3.2 A number of participants have expressed concerns around the process and in particular the amount of consultation it involved, in particular in relation to the PF requirement in the Connection Code.

3.3.3 The Commission carried out a thorough consultation process on this, including a specific cost benefit analysis, and specifically:

- (a) asked, in its consultation paper of 19 October 2007⁵ (**Original Consultation Paper**) whether submitters:
 - (i) had any comments on the results of the preliminary analysis;
 - (ii) had any additional analysis they would like the Commission to consider;
 - (iii) considered there to be other values for leading or lagging power factors that should be set out in the proposed Connection Code that better meet the requirements for the Connection Code, and if so, why this was the case; or
 - (iv) had views on the appropriateness of the common standards proposed;
- (b) held a briefing⁶ on the proposed Connection Code on 12 November 2007 to enable participants and affected parties to provide further comment on the proposals;
- (c) extended the closing date for submissions on the draft Connection Code to 22 November 2007 to take account of any further understanding developed at the briefing; and
- (d) considered submissions received from generators/retailers, distributors, consumers and Transpower.

Q2. Do you agree that the summary of the Commission's process is correct?

⁵ Electricity Commission, *Consultation Paper: Proposed Connection Code and Outage Protocol*, dated 19 October 2007

⁶ The briefing also covered the Outage Protocol and Interconnection Measures.

- 3.3.4 In the Original Consultation Paper, the Commission considered Transpower's view that a PF not less than 0.95 lagging, or 0.95 leading at peak times (**Transpower's PF Proposal**), was the only practicable option. It queried whether an alternative minimum PF value could be more appropriate as a value of 0.95 in some areas may not facilitate efficient decisions on new investment. The Commission proposed that the value of 0.95 for the minimum PF in clause 4.4 of the draft Connection Code be substituted for an alternative value of 1.0 at peak times in the case of the UNI and USI regions (**Commission's PF Proposal**) (as was eventually adopted, as set out in paragraph 2.1.4 above).
- 3.3.5 The two primary concerns of submitters with respect to the PF requirement were:
- (a) the underlying analysis highlighting the benefits; and
 - (b) the ability of lines businesses to recover the costs of any mitigation measures.
- 3.3.6 Some submitters questioned some of the analysis in the consultation documents, in particular with reference to areas in distribution networks where there are a greater proportion of underground cables than overhead lines. However, there is agreement that improvements in PF in the rural and lower population density parts of the UNI and USI via investments in reactive power sources would usually be more efficient than new transmission lines or grid-connected reactive compensation.
- 3.3.7 Some lines businesses expressed concern that they may not be able to recover the costs they would face in maintaining a PF of unity in the UNI and USI at times of peak load (rather than Transpower having the obligation and/or having a lower requirement). If they have to meet the obligation themselves, they said that the current price threshold regime administered by the Commerce Commission might not allow them to pass this cost on to their customers.
- 3.3.8 The Commission is not convinced that this is necessarily an issue, but noted that this issue is within the scope of the Commerce Commission's jurisdiction (rather than the Electricity Commission's) to resolve. It should not be reason in itself to prevent the implementation of an obligation that will better reflect the cost of providing reactive support in these regions to the causers.

3.4 Assessment of costs and benefits⁷

- 3.4.1 As part of its process for approval of the Connection Code, the Commission assessed Transpower's PF Proposal, identified what it considered to be reasonably practicable alternatives, and assessed these against it as required by section 172F of the Electricity Act 1992 (**Act**). One such alternative was the Commission's PF Proposal.
- 3.4.2 The Commission undertook preliminary work on the proposal and the alternative, providing the analysis with the Original Consultation Paper. The Commission requested that submitters comment on these initial results. The Commission was

⁷ This section is a summary of the "costs and benefits" section of the Original Consultation Paper.

particularly interested in submitters' views on the PF that would lead to the most efficient investment being made in voltage support in the USI and UNI.

Benefits

- 3.4.3 The Commission considered that the Commission's PF Proposal has the following benefits over Transpower's PF Proposal:
- (a) It would appear to reduce both the amount of grid-connected reactive compensation required to be provided by Transpower and also energy losses within the distribution networks themselves.
 - (b) It would likely reduce the number of GXPs where the PF is currently less than unity.
 - (c) It would lead to greater efficiency in investment decision-making when the transmission grid is voltage constrained, as connected parties would directly face the costs of taking supply at a lower PF consistent with the causer pays principle.
 - (d) The opportunity it provides for a negotiated solution (rather than a centrally imposed solution) to PF correction could lead to innovative approaches in the provision of reactive power being implemented. The two-year transition period allows time for this negotiation to occur and gives parties enough time to investigate and plan for the most efficient solution to the provision of reactive support. This was consistent with the underlying approach to the Connection Code leaving many matters at a general level, rather than actually specifying detailed standards and regulations.
- 3.4.4 The Commission's preliminary estimate of the overall benefit of the Commission's PF proposal was between \$12m and \$90m⁸. After considering submitters' views on this the Commission concluded that, while the analysis overstated the benefit in certain circumstances (e.g. urban low loss underground high voltage networks), it did not fully reflect the efficiency gains from better reflecting costs to causers. Therefore, it considered that the expected benefits are likely to be within this range.

Costs

- 3.4.5 When assessing the alternative (Transpower's PF Proposal), the Commission noted that the actual average PF is higher in both regions. DTCs have invested or provided pricing signals to consumers in their networks to ensure a higher PF than required by previous connection requirements and so it may be unnecessary to specify a higher minimum level than 0.95.

⁸ See paragraph 4.6.28 of the Original Consultation Paper. Assuming a peak demand of 1100MW in the USI and 2070MW in the UNI, if all connected parties only achieved the minimum 0.95 PF rather than unity, then net costs of \$284,000 per year per 100MW of demand would give an overall total of \$9m per year or approximately \$90m present value cost. However, if current levels of around 0.98 PF were maintained rather than unity then net costs of \$38,000 per year per 100MW of demand, would give an overall total of \$1.2m per year or approximately \$12m present value cost.

- 3.4.6 The Commission noted that there are administration costs associated with Transpower and DTCs:
- (a) investing in reactive compensation equipment within the distribution network;
 - (b) in the short term, negotiating a TA or entering a non-compliance agreement to address non-compliance; and
 - (c) in the longer term, negotiating an agreement to rectify non-compliance where Transpower invests in sources of reactive power but the causer pays.
- 3.4.7 In addition, the Commission considered that there may be enforcement costs under the proposal through lines businesses refusing to undertake the investment if they believe it will be difficult for Transpower to enforce the unity PF.
- 3.4.8 If networks sought to profit maximise and shift the cost burden on to all customers by allowing the PF to fall over time (e.g. from its current measured average of approximately 0.98 to 0.95 (the alternative standard)), this would have significant impact on the need for grid investment and would be a significant cost attributable to the alternative.
- 3.4.9 The Commission also considered, taking into account comments from lines businesses, that there may also be some additional costs for lines businesses in having to provide justification to the Commerce Commission for recovering any costs from customers that they incur in meeting the PF obligation.
- 3.4.10 It noted that it was possible that efficient costs could be recovered under the Government's proposed new regime in the Commerce Amendment Bill if DTCs propose a customised price/quality path⁹.
- 3.4.11 Accordingly, it is difficult to predict the level of costs that lines businesses would incur but these are likely to be part of a larger group of costs not explicitly recognised by the current regulatory regime that lines businesses are seeking to recover. Hence the Commission considered, at the time, that regulatory costs are likely to be low and incremental.

Conclusion on benefits and costs

- 3.4.12 The Commission concluded that its proposal had a higher net benefit than the alternative given:
- (a) the improvement in investment decision-making in respect of the UNI and USI as connected parties would directly face the costs of taking supply at a lower PF consistent with the causer pays principle;
 - (b) the potential reduction in both the amount of grid-connected reactive compensation required to be provided by Transpower and energy losses within the distribution networks themselves in these regions;
 - (c) the significant cost of new transmission investment if networks in the voltage constrained UNI and USI regions permitted the PF to fall over

⁹ The Commerce Amendment Bill has been passed into law.

time from actual levels to the level specified in the reasonably practicable alternative; and

- (d) that the delay in the implementation date would enable non-complying DTCs time to investigate their options, noting that in many cases, the most efficient investment would be in reactive sources within the line companies' networks.

3.5 Measurement Problems

3.5.1 The Commission notes that concerns have been expressed about the practicability and cost of measuring conformity with the PF requirements in the Connection Code. The concerns appear to cover two issues:

- (a) The PF requirement is impractical because the current var-hour meters at grid exit points (GXPs) cannot measure PF accurately enough to measure whether designated transmission customers have breached the contract terms in the TA.
- (b) It is not possible to maintain a PF of more than 1, as the wording of clause 4.4(a)(2)(i) of the Connection Code currently implies. A number of participants say that this should have been expressed as a PF of 1 rather than "not less than" 1.

Capability of current metering

3.5.2 The Commission has advice (see Appendix 2) showing that measurement is feasible with currently installed GXP metering.

3.5.3 Summarising the advice received:

- (a) all GXPs are required to have var-hour meters of accuracy Class 2 or Class 3 installed;
- (b) the Class 3 meters are the least accurate and are considered as the worst case in analysing whether PF can be measured accurately enough to assess contractual breach;
- (c) IEC 61268 specifies the accuracy at high load for Class 3 meters as:

Accuracy for Class 3 var-Hour Meters

Sin Φ	Cos Φ PF	% Error Limit
1	0	$\pm 3\%$
0.5	0.87	$\pm 3\%$

Sin Φ	Cos Φ PF	% Error Limit
0.25	0.97	$\pm 10\%$

3.5.4 The percentage error is defined as:

$$\% \text{ Error} = 100 \times \frac{(\text{Reactive Energy registered by the meter} - \text{Reactive Energy})}{\text{Reactive Energy}}$$

3.5.5 As the PF moves close to unity and the reactive power (Mvar) approaches zero, then the percentage error will become very large. This is why the percentage error limit increases from +/-3% to +/-10% as the PF increases. Industry participants have noted this and commented that the var-hour meters will not be able to accurately measure compliance with the transmission agreement terms because of the large error factor.

3.5.6 The Commission considers that concerns about the large measurement error as the PF approaches unity is misplaced. The Commission notes that:

- (a) the PF is calculated by dividing the active power (in MW) by the apparent power (in MVA) at a "point of service"¹⁰;
- (b) apparent power (MVA) is calculated by reference to the reactive power (Mvar);
- (c) as the PF increases towards unity, the amount of reactive power reduces (measured Mvars reduce);
- (d) while the measurement error may increase, the increased error has a minimal effect on the apparent power measurement; and hence the measurement error for the PF;
- (e) at close to unity power factor the active power is almost equal to the apparent power; therefore the error in absolute reactive power can be expected to be about +/- 0.03% of the active energy measurement.

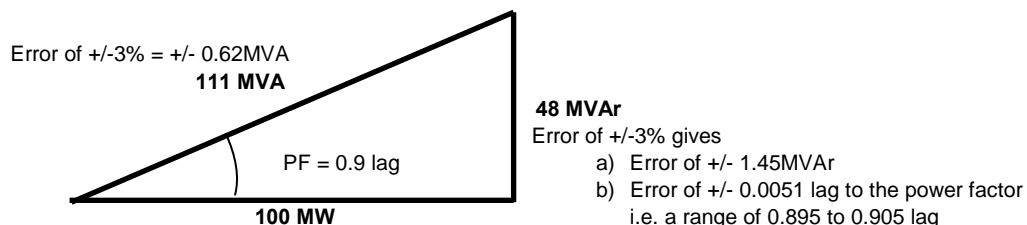
3.5.7 The Commission further considers that when assessing compliance and agreeing to non-compliance or equivalence arrangements in TAs, Transpower should consider the underlying rationale for this requirement in the Connection Code (i.e. incentivising efficient investment over time and while maintaining grid reliability). This would not necessarily require all DTCs to meet the Connection Code requirements for each of the 12 regional coincident peak measurements in a given year. However, the issue of compliance would be material and important if it had a material impact on Transpower's plans for investment over time.

¹⁰ as defined in part A of the Rules

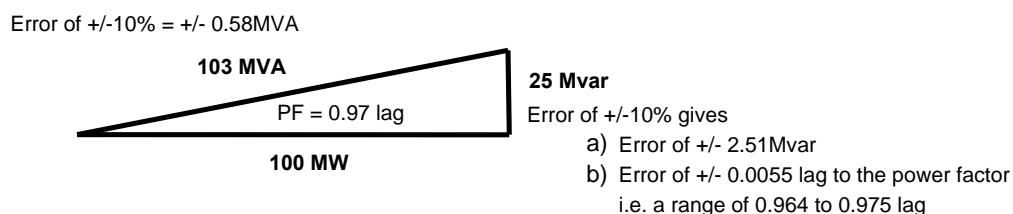
Q3. Do submitters consider that this a practicable and workable interpretation of the PF requirement? Do submitters consider that the Commission has to provide further guidance (see question Q30)

3.5.8 This is demonstrated below by comparing the measurement error for the observed PFs for the same point of service but assuming different amounts of reactive power being drawn from the grid:

- (a) assuming that the Class 3 var-hour meter is reading 48 Mvar (reactive power) with a measurement error of +/-1.45Mvar (+/- 0.03%). The active power reading is 100 MW. The calculated apparent power is therefore 111 MVA with a measurement error of +/- 0.62 MVA. The calculated PF is therefore 0.9 with a measurement error of +/-0.0051.



- (b) Assuming that the Class 3 var-hour meter is reading 25 Mvar (reactive power) with a measurement error of +/-2.5Mvar (+/- 0.10%). The active power reading is 100 MW. The calculated apparent power is therefore 103 MVA with a measurement error of +/- 0.58 MVA. The calculated PF is therefore 0.97 with a measurement error of +/-0.0055.



3.5.9 The table below summarises the results:

Power Factor	Error	Range
0.9	+/- 0.0051	0.895 to 0.905
0.97	+/- 0.0055	0.964 to 0.976

- 3.5.10 The Commission considers that Class 3 var-hour meters (and by implication Class 2 meters) are accurate enough to measure compliance with the Connection Code with respect to the PF requirement.
- 3.5.11 The Commission notes that if the measured reactive power being drawn from the grid over a half-hour period is close to zero, allowing for the accepted measurement error, then compliance with the required standard in the Connection Code should be met: clause 4.4 requires that customers:
- (a) do not *unreasonably* draw reactive power resources from the grid; and
 - (b) maintain the set PF requirements (which are measured over a half-hour period).
- 3.5.12 It would be reasonable to expect and accept some minor deviations within the half-hour measurement period, provided that at most times reactive power is not being drawn from the grid.
- 3.5.13 The Commission also notes that IEC 61268 has been superseded by IEC 62053-23 which requires smaller error limits of +/-4% for Class 3 meters and +/-2.5% for Class 2 meters at 0.97 PF. All new and replacement Class 2 and 3 meters must conform to this new standard¹¹. It is expected that this would result in even smaller reactive energy errors at unity power factor than the present meters meeting IEC 61268.

PF of more than 1

- 3.5.14 A number of participants have commented that it impossible to have a PF of more than 1. The Commission agrees that it is not possible to maintain a PF of more than 1 but considers that this does not require changes to the requirement: “not less than” 1 can simply be interpreted as 1.

Q4.	Do you agree with Commission’s view on the measurement issue?
Q5.	Do you consider that it is reasonable to expect and accept minor deviations within the half-hour measurement period or over a longer period?
Q6.	Do you have other concerns about the PF requirement?

¹¹ Existing meters will only have met IEC 61268.

3.6 Part C integration issues and unity power factor system operability issues

Integration with part C

- 3.6.1 The Commission's Common Quality Development Plan includes a task to investigate a market mechanism to provide reactive power. The Common Quality workstream has initiated a review of the current arrangements with the aim of reducing the current cost of providing reactive power support (which is approximately \$8m p.a.¹²), improving the fairness of cost allocation and accessing any reactive power capability that generators may have in excess of the mandated requirements under part C of the Rules.
- 3.6.2 The main existing part C arrangements to ensure the provision of sufficient reactive power are:
- (a) the SO's Principal Performance Obligations under rule 2.1 and 2.3 of section II of part C of the Rules (**PPOs**) to avoid cascade failure and manage voltage fluctuations;
 - (b) the Asset Owner Performance Obligations (**AOPOs**) that:
 - (i) generators must be capable of importing and exporting specified quantities of reactive power over specified voltage ranges; and
 - (ii) Transpower and grid-connected assets must be capable of operating at a specified range of voltage levels;
 - (c) the allocation of reactive power procurement costs to:
 - (i) lines businesses and direct connect customers through a peak reactive power demand charging regime; and
 - (ii) non-compliant generators (those that cannot meet the AOPOs) who have entered into an equivalence arrangement.
- 3.6.3 The major integration issue between parts F and C of the Rules is the co-ordination of investment requirements between part C and part F. Coordination will ensure that:
- (a) the long-term investment in reactive power supply ensured by part F processes is not duplicated by procurement by the SO; and
 - (b) any short-term deficiencies (e.g. because of planning errors) are covered by the SO purchasing reserve reactive power support.
- 3.6.4 However, even reserve reactive power support requirements can be assessed and provided by part F processes when decisions are made about the required capability of the reactive power supply assets and the costs and benefits of doing so. This is because the Grid Investment (**GIT**) recognises the cost of ancillary service provision.

¹² This cost is incurred by the SO in procuring dynamic reactive power that is required in addition to that available from generators or Transpower.

- 3.6.5 The need for historical and ongoing purchases by the SO is driven primarily from a lack of long-term investment in reactive power reserve equipment within specific regions. However, the Commission considers that while it may not completely replace SO purchases (which may also vary depending on the system requirements, over time), part F enabled investment in reactive power sources should substantially reduce the need for SO purchases.
- 3.6.6 The Commission considers that the part F processes for decisions about the supply of reactive power are more efficient than the current part C procurement arrangements. The short-term contracting arrangements mean that investors have to recover the costs of the reactive power plant over a one to three-year period whereas the part F processes would result in greater revenue certainty and a longer payback period. The mandatory requirements on generators and others (AOPOs) should remain in place as the marginal cost of this arrangement is low or zero. In addition, it can be regarded as a requirement of access to the interconnected grid.
- 3.6.7 At present the SO purchases dynamic reactive power support in accordance with its procurement plan. This currently amounts to approximately \$8m per annum. While the SO requirements are short term in nature, in recent years it has been necessary for the SO to consider longer-term contracting arrangements (such as for Contact Energy's Otahuhu A generation station) in order to ensure it meets the requirement that sufficient reactive power support is available.
- 3.6.8 Prior to full implementation of an option, there are transitional issues that may need to be addressed by the Commission. For example, in the UNI the SO uses an N-G-1 planning assumption that reflects agreement with its Upper North Island Working Group but may differ from assumptions used by the grid planner. Different assumptions may lead to additional SO purchases being made in the short term.
- 3.6.9 The SO may also need to procure reactive power support for some time as there may be a delay in the planned investments by the grid owner. Investments by the grid owner in reactive power reserve may take a number of years to implement and need to be prioritised with other investments being undertaken by the grid owner.
- 3.6.10 However, the Commission considers that the management of these system operational issues are not prohibited by any of the options considered in this Issues Paper, and that by having an incentive on DTCs to efficiently invest in reactive equipment the overall investment and operational efficiencies are likely to increase.

Unity power factor system operability issues

- 3.6.11 The Commission has asked the SO to provide some initial comments to include in this Issues Paper in order to generate discussion about the significance of the system operation issues that may arise because of the PF requirement. The SO has provided comments in the absence of any detailed studies that reflect its anecdotal observations. The comments provided by the SO have been annotated for incorporation and where relevant the Commission has commented on the issues highlighted.

High transmission voltages under light load

- 3.6.12 A transmission line's series inductance produces lagging reactive power and its shunt capacitance leading reactive power. Lagging reactive power varies in proportion to line current whereas leading reactive power varies with the square of voltage and is relatively constant under normal operating conditions. As a result, net reactive power is generally leading when line load is light and lagging when load is heavy.
- 3.6.13 Some long transmission lines can produce considerable quantities of leading reactive power under light load conditions which results in high line voltages. Lagging power factor in GXP demand at off peak times can help to offset the leading reactive power from lightly loaded lines and other leading reactive sources such as distribution cables. Lagging load power factor is a means to avoid other mitigation measures such as installing grid reactors or switching out parallel circuits which increases losses and can create market constraints.
- 3.6.14 There is potential for GXP demand power factor to be leading at off peak times when a requirement for customers to maintain unity power factor during regional peak demand periods is imposed. If not managed, this could result in unacceptably high voltages on parts of the grid where there is also a leading reactive power contribution from transmission lines during periods of light load.
- 3.6.15 The problem can be addressed by installing power factor correction capacitors which are designed to be switched in multiple steps. With good voltage control systems and capacitor step sizing, customers and/or Transpower could actively vary load power factor during the daily load cycle to maintain a relatively constant GXP voltage. Transpower has considerable discretion under existing clauses 2.3 and 5 of the connection code to ensure that equipment connected to the grid by customers complies with any special requirements specified by Transpower and does not adversely affect the grid. Special requirements may include SO control of capacitor switching.
- 3.6.16 The Commission's observation is that Transpower may have to require that switching is provided on some future grid or distribution connected capacitors. There would be a need for capacitor switching requirements to be communicated to DTCs by the grid owner.
- 3.6.17 The Commission notes that capacitors with these features have been used by Westpower Limited¹³ at Greymouth for over a decade, new installations have been provided for in other places including Hokitika and Kaitaia.
- 3.6.18 The arrangement between Transpower and the MDF plant connected at the Brydone GXP is a good example of a bilateral arrangement relating to the correction of power factor and the installation of capacitors. In this case, the customer paid for Transpower to install capacitors at the Brydone sub-station rather than make any modifications to the customer's plant and these capacitors are controlled to manage grid capacity while also meeting the PF obligation when this is necessary.

Regional voltage considerations

Taranaki

¹³ Westpower Limited distributes electricity on the West Coast of New Zealand.

- 3.6.19 The transmission grid in the Taranaki region is known to experience high voltage at periods of light load, especially when the Stratford Power Station is out of service and cannot be used to absorb reactive power overnight. Operational measures taken by the SO to overcome this problem include the use of reactive capability at Mangahao or Tokaanu when these generators are running, as well as operating the HVDC link in half pulse mode if in north transfer.
- 3.6.20 The relatively poor demand power factor in the Taranaki which varies between 0.90 and 0.95 lagging has a beneficial effect in suppressing high grid voltages in this region. Taranaki is in the LNI and accordingly, under the Connection Code, customers in this region are required to maintain a minimum PF of not less than 0.95 lagging at regional peak demand periods, as opposed to unity. It is unlikely that the connection code requirements would degrade voltage quality in the Taranaki region provided that additional capacitors installed as a result of the code were able to be switched out during periods of light load..
- 3.6.21 The Commission notes that planned changes to the operation of generation at Hawera will also assist to resolve this issue.

Auckland and North Auckland

- 3.6.22 Auckland and North Auckland is a voltage constrained region and is unlikely to be adversely affected by high voltages during periods of light load. In addition, the SVC recently commissioned at Albany by Transpower has the capability to absorb reactive power.
- 3.6.23 Some problems have been experienced in the Albany area as a result of injection of reactive power at the GXP during periods of light load from customer installed capacitors. These problems highlight the need discussed in paragraph 3.6.15 for Transpower and its customers to ensure that adequate control of demand PF is maintained through the use of good voltage control systems and capacitor step sizing.

USI during summer

- 3.6.24 Prior to the commissioning of the third 220 kV circuit to Kikiwa, Transpower identified that this additional circuit may have to be switched out at times of low load initially until the Nelson regional demand increases.
- 3.6.25 During the period between February and April 2008 one of the three circuits into Islington had to be removed on several occasions as well as the Islington-Kikiwa 1 circuit to avoid extreme high voltages in the top of the South Island.

3.6.26 The Connection Code requirement for customers to maintain a minimum PF of not less than unity at regional peak demand periods may adversely affect the high voltage problem in the top of the South Island if adequate control of demand PF is not maintained during periods of light load. However, the static var compensators (**SVCs**) that Transpower plans to install at Islington and Kikiwa in 2009 are expected to resolve this problem.

Q7. Do you agree with assessment of Part C integration issues? Are there more?

Q8. Do you agree with assessment of system operation issues? Are there more?

4. Option Analysis

4.1 Introduction

4.1.1 The analysis section of this paper is structured as follows:

- (a) characteristics of the supply and demand for reactive power;
- (b) assessment framework; and
- (c) discussion of the options.

4.2 Characteristics of the supply and demand for reactive power

4.2.1 The physical characteristics of reactive power can make the regulatory and market requirements that surround its provision relatively complex. These include the following:

- (a) Reactive power is difficult to transport over the transmission system and it is inefficient to do so as substantial transmission losses occur. Consequently it needs to be supplied locally and so markets are likely to be smaller and less liquid.
- (b) There are often several alternative technologies that can be used to supply reactive power demand. These include static devices that are either switched on or switched off through to rotating machines that can continuously respond to changes in demand. Each type is useful in different circumstances and dependent on the nature of the demand itself. The different requirements for reactive power supply need to be accounted for in any regime.
- (c) While it is local (or regional) in nature, reactive supply impacts on the transport of active power between regions. Additional transmission capacity can be required due to a lack of local reactive power support. Hence, supplying an appropriate amount of reactive power locally can lower transmission investment costs.
- (d) Transmission and distribution networks themselves are both suppliers and consumers of reactive power, as discussed above in paragraph 3.6.12. This is dependent on the configuration of the network and amount of load on the circuits. Too much reactive supply can lead to over voltage situations which are as damaging as not having enough. Therefore any regime needs to account for these characteristics and the operational consequences of them.
- (e) Investments in static reactive power equipment are relatively cheap compared to the costs of supplying active power. This means the level of administration costs a market or regulatory structure can support is much lower for reactive than for active power.

- 4.2.2 Many of these issues interact with each other and therefore these aspects all need to be accounted for in whatever regime is determined to be the most appropriate.
- 4.2.3 In summary, demand for reactive power is driven from two sources:
- (a) *Consumer demand*—this depends on the type of load consumers place on the system. It varies between residential customers (e.g. some have heat pumps and fluorescent lighting; others don't), industrial customers (typically motor loads and process requirements) and commercial customers.
 - (b) *Transmission and distribution networks*—Transmission is as discussed in paragraphs 3.6.12 and 3.6.13. Distribution networks display similar characteristics.
- 4.2.4 Currently the supply of reactive power support is provided by:
- (a) *PF compensation at end user premises*—many industrial consumers with motor loads are required by the local network company to install PF correction equipment to allow efficient management of the local network;
 - (b) *Network company investments in capacitor banks within their distribution networks*—these are smaller-scale investments than grid-connected capacitor banks and in some areas include distributed pole top capacitors. Some of these are capable of being switched and typically they require manual operation. Capacitor banks are static devices (i.e. either on or off), and are usually not relied on to provide any dynamic support;
 - (c) *Transpower via investments in capacitor banks, SVCs¹⁴, static condensers¹⁵, and synchronous condensers¹⁶*—these are all grid-connected sources of reactive power. Capacitors are simply larger scale than distribution network connected devices, except that some economies of scale are present which typically don't exist on distribution networks. SVCs and static condensers are dynamic devices that rely on power electronics, while synchronous condensers are dynamic, rotating machines; and
 - (d) *Generators*—via a mandatory requirement to supply reactive power in part C of the Rules¹⁷.

¹⁴ A static var compensator (or SVC) is an electrical device for providing fast-acting reactive power compensation on high-voltage electricity transmission networks.

¹⁵ A static condenser is an advanced static var compensator using voltage source power converters with capacitors connected on the DC side.

¹⁶ A synchronous condenser is an electrical device that can compensate either a leading or lagging PF, by absorbing or supplying reactive power to the line.

¹⁷ See rule 3.2 of section III of part C of the Rules.

- 4.2.5 The reactive power supply sources can be categorised into three types of equipment:
- (a) a base level of static reactive power support provided by either distribution network or grid-connected capacitor banks (some can be switched on and off but are done so in steps);
 - (b) dynamic power electronic controlled devices such as SVCs or static condensers that provide reactive power reserve and that respond swiftly if a fault occurs on the power system; and
 - (c) rotating machines such as synchronous condensers and generators that provide both a base level of reactive power supply and the ability to respond to a system fault.
- 4.2.6 An appropriate, and often location specific, balance between these sources of reactive power needs to be struck to ensure efficient design and operation of a power system.
- 4.2.7 The issues raised concerning the unity PF Connection Code requirement are related to a subset of the demand and supply components set out above and are focused on the static reactive power requirements of demand at a GXP level. Therefore the options presented in this paper are focused on the alternative structures for the supply of reactive power to meet the net consumer demand and distribution network demand.
- 4.2.8 The Commission has not considered demand for reactive power driven from the transmission system in this paper. It is assumed that, where investment is required for the transmission system, the processes in section III of part F of the Rules will continue to apply, i.e. Transpower as grid owner will propose investment to cover transmission requirements as part of a grid upgrade plan (**GUP**) and subject to the GIT. However, there are exceptions to this:
- (a) In real time the SO will still need to account for the requirements of the transmission system (both supply and demand), as discussed above in section 3.6.
 - (b) There are variations to some of the options that would mean that all reactive power investment required within a region could be included in the pricing mechanism, i.e. fully reflect the causer pays principle.
- 4.2.9 The supply of dynamic reactive power support is also not explicitly considered in this paper. The Commission considers that the standard processes associated with the approval of a GUP should be sufficient to account for dynamic support.

Q9. **Do you agree that the options should cover GXP demand for reactive power only?**

4.3 Assessment Framework

- 4.3.1 Some of the options discussed below would require changes to the Rules. The Act provides a process for any such changes and a set of criteria against which they need to be assessed.

4.3.2 As part of that process, the Commission is required by section 172F of the Act to:

- (a) seek to identify all reasonably practicable options; and
- (b) assess those options by considering:
 - (i) the costs and benefits of each option;
 - (ii) the extent to which the objective would be promoted or achieved by each option; and
 - (iii) any other matters the Commission considers relevant.

4.3.3 The Commission is required by section 172X of the Act to give effect to its principal objectives and specific outcomes set out in section 172N of the Act and its GPS objectives and outcomes. These include the following:

- (a) the **principal objectives** of the Commission under section 172N(1):
 - (i) to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner; and
 - (ii) to promote and facilitate the efficient use of electricity.
- (b) the Commission's **specific outcomes** under section 172N(2) that:
 - (i) energy and other resources are used efficiently;
 - (ii) risks (including price risks) relating to security of supply are properly and efficiently managed;
 - (iii) barriers to competition in the electricity industry are minimised for the long-term benefit of end-users;
 - (iv) incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment;
 - (v) the full costs of producing and transporting each additional unit of electricity are signalled;
 - (vi) delivered electricity costs and prices are subject to sustained downward pressure; and
 - (vii) the electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables, and distributed generation.

4.3.4 A summary of the assessment of each option against the criteria is set out in section 4.9 below.

4.4 Options

4.4.1 Set out below are four options for considering the supply of reactive power. Each option is representative of a broader range of options, with variation possible on

each. Some of these variations are discussed, but for the purposes of clarity, not all variations have been presented in this paper. However, the Commission is interested in hearing from submitters on any variation that should be considered in more detail.

- 4.4.2 The four options presented are:
- (a) the Connection Code option (status quo);
 - (b) the market option;
 - (c) the administered charge option; and
 - (d) the no-obligation option.

4.4.3 Each is discussed in turn below.

- Q10. **Do you consider there are other reasonably practicable options?**
- Q11. **Are there other variations that the Commission should consider in more detail?**

4.5 Connection Code option (the status quo)

4.5.1 This option retains the status quo as currently expressed in the Connection Code and the TPM. The PF requirement is:

4.4 Minimum power factor:

- (a) *The Customer must ensure that its Equipment does not unreasonably draw on the reactive power sources of the **grid** during each regional peak demand period. If **electricity** is being drawn off the **grid** the Power Factor at any Point of Service the Customer must:*
 - (1) *up until 31 March 2010, in the case of demand, maintain a Power Factor of not less than 0.95 lagging at any Point of Service during each relevant regional peak demand period.*
 - (2) *from 1 April 2010, in the case of demand, maintain a Power Factor of not less than:*
 - (i) *1.0 (unity) at each relevant Point of Service during each relevant regional peak demand period in the Upper North Island Region and the Upper South Island Region; and*
 - (ii) *0.95 lagging at each relevant Point of Service during each relevant regional peak demand period in the Lower North Island Region and the Lower South Island Region.*

4.5.2 Each DTC would continue to be required by the Connection Code to meet minimum PF requirements during times of regional peak demand (as defined in

the TPM) when power is being drawn off the grid. There would continue to be the opportunity under the Connection Code for parties to enter into non-compliance (equivalence) arrangements with Transpower as part of a TA, which could provide for Transpower to provide grid support or recognise contracts with third party asset providers. As at present, the Connection Code requirements would be enforced bilaterally through the TAs.

- 4.5.3 Due to the ability for a connected party to enter into a non-compliance agreement with Transpower, any single GXP may not meet the minimum PF requirements. Rather, (as at present) the combination of bilateral charging arrangements (including third party contracts and internal self covering for those at multiple GXPs) would ensure that PF requirements for the region are met.
- 4.5.4 This option depends on Transpower treating voltage support assets that it installs at GXPs in order to provide reactive power support to DTCs as connection assets.
- 4.5.5 Investment in reactive power equipment required to meet the reactive power demands of the transmission system, along with any equipment for reactive power reserve requirements, would continue to be dealt with through the investment approval process in section III of part F of the Rules.
- 4.5.6 As each DTC would be responsible for meeting the minimum PF requirements, they would be incentivised to find the most efficient method of supplying their own reactive power demand through the active use of equivalence arrangements.

Counterparties to the Connection Code option

- 4.5.7 The counterparties are the TA counterparties (the Connection Code is a schedule to the TAs). Bilateral equivalence arrangements would be between suppliers of reactive power equipment (Transpower and others) and connected parties, recognised in non-compliance agreements entered into with Transpower under the Connection Code.

Implementation requirements

- 4.5.8 This option requires no changes to the Rules.
- 4.5.9 While there is no obligation on Transpower to enforce the unity PF requirement under a TA (it is free to grant equivalence), where a DTC's failure to comply with the unity PF impacts on the GRS at the GXP, this would incentivise Transpower to enforce it.
- 4.5.10 The parameters around establishing equivalence arrangements or non-compliance agreements may need to be established, but this may not need Rule changes.

Variations

Clarify TPM interpretation

- 4.5.11 If Transpower may not necessarily treat reactive support assets installed at GXPs that can also be used for grid voltage as connection assets, a possibility is to review the TPM with the aim of making it clear how such assets should be treated. The options include:

- (a) making it clear that assets that provide reactive power at the regional coincident peak are connection assets (as the Commission considers is currently the case); or
- (b) dividing the costs of those assets between connection and interconnection according to their expected use at the time of coincident peak.

Q12. Do you consider that a clarification of the TPM definition of connection assets is required (see related question Q1)?

- 4.5.12 If the TPM is reviewed, it may also be necessary or at least advisable to review the GRS and/or the investment approval processes under section III of part F of the Rules to exclude reactive power demand from DTCs, although interrelationships with other issues under section III would also need to be considered. Related changes to processes under the Interconnection Rules and the BA for considering new investments may also be needed.

Q13. Do you consider that any of the GRS, section III of Part F of the Rules, the Interconnection Rules or the BA would also need to be reviewed?

PF Standard

- 4.5.13 There are a number of potential variations for the definition of the PF standard that may be used to address the practical difficulties in achieving an exact PF at any specific point in time. These include the following:
- (a) The standard could be absolute, as currently exists in the Connection Code (taking into account the fact that a PF cannot be more than 1.0, as explained in paragraph 3.5.14 above). This requires absolute conformity for the duration of the peak demand period.
 - (b) The standard could allow for some variation, such as by allowing for non-compliance for some period of time, so that, for example, the PF should not drop below the threshold for more than, say, five minutes per year.
 - (c) It could be held within a specified band, for example +/- 0.005 (leading/lagging) of the standard. The upper limit of any band would be a PF of 1.0.

Q14. Do you consider that one of the above potential variations for the definition of the PF standard is superior? If so, why? Are there other options?

Compliance and enforcement

- 4.5.14 The Commission considers that many of the variations above are reflected in any practical application of an absolute standard. Seldom do measurements exist of any real world quantity that establish with absolute certainty, absolute compliance. In the end it comes down to whether the practical intent has been achieved when assessing compliance and the materiality of any possible aspects of non-compliance.
- 4.5.15 This means that Transpower should take a pragmatic approach to assessing if a party has complied with the unity PF obligation. This may include such

mechanisms as notices that a breach is likely to or has already occurred, a consultation process between the parties concerning the establishment of an equivalence arrangement or other steps that may be considered relevant by Transpower.

- 4.5.16 While not part of the Rules, it may be appropriate that a compliance policy is agreed between Transpower and the Commission in order to remove any doubt. The Commission's view is that if Transpower and the DTC can demonstrate that steps are being taken toward rectifying any non-compliance, then in principle it should not impact on the approval of any specific GUP application, although this will depend on the specific circumstances surrounding an investment.

- Q15. **Do you consider that a pragmatic approach to assessing contractual compliance is appropriate (see related questions Q3 and Q5)?**
- Q16. **Do you consider that Transpower and the Commission should develop a compliance policy?**
- Q17. **Do you consider that an appropriately worded compliance policy would help remove any doubt as to how the enforcement of unity PF obligation would impact on a GUP?**

- 4.5.17 There have also been several queries from industry participants as to the appropriateness of enforcement options under the current Connection Code implementation.

- 4.5.18 There are a number of options for the legal framework under which the PF standard could be enforced. The default is that the standard is set within the Connection Code and enforced through the bilateral contract between Transpower and connected parties, with redress available to the courts. However, the alternative options are:
- (a) including the standard within the Rules themselves with redress through the Rulings Panel;
 - (b) providing (either in the Rules, the BA or a guideline or policy such as the grid upgrade investment review policy (**GUIRP**)) that, if a connected party fails to meet the standard over some time period, Transpower invests in an equivalence arrangement and levies the cost on the connected party ;
or
 - (c) specifying a cost-based shortage charge for non-compliance with the connection standard which would be set at such a rate that it was economic for the connected party to invest in local GXP reactive power equipment. The shortage charge could be prescribed within the Rules or under the BA. If it were under the Rules, any charge must not breach the restriction of remedies set out in section 172KF of the Act and must be in accordance with the Rulings Panel's powers to make orders under section 172KE of the Act. If it were under the BA, the charge would likely need to be related to the costs incurred by Transpower as a result of non-compliance.

Advantages and disadvantages

- 4.5.19 The advantages of the Connection Code option are that:
- (a) no changes to the existing Rules are needed unless the Board decided to clarify the treatment of mixed-purpose voltage support assets under the TPM or one of the variations discussed in paragraphs 4.5.11 to 4.5.18 above were adopted, i.e. it has low set up costs;
 - (b) it encourages innovative and dynamically efficient solutions for meeting distributor and consumer reactive power demand; and
 - (c) it is relatively simple to administer, although in practice, if DTCs refuse to meet the specified standard and the required reactive power support does not pass the GIT, it ultimately relies on Transpower suing its customers. In extreme cases like these, this option may have higher administration costs. It also relies on establishment of bilateral and ongoing renewal of equivalence arrangements unless these arrangements are provided for in a TA.
- 4.5.20 The overall level of administration costs for the Connection Code option has been classed as medium.
- 4.5.21 A potential disadvantage is that it largely depends on how Transpower applies the TPM and enforces the standard in its TA with its DTC.

Preliminary cost benefit analysis

4.5.22 A summary of the costs and benefits of the Connection Code option are:

Criteria		Connection Code
Principal Objective		✓✓✓
Costs (set up, administration)		Low setup costs, Low admin costs from not having to change rules
Specific outcomes (benefits)	Efficiency	✓✓
	Risk managed	✓✓✓
	Barriers to competition minimised	✓
	Incentives for investment	✓✓
	Full costs of production and transport signalled	✓✓
	Sustained downward pressure on prices	✓✓
	Contributes to climate change objectives	✓✓
Net Benefit		✓✓+

(Assessments range between * and ✓✓✓)

Q18.	Do you agree that the Connection Code option (a PF of unity in the selected regions and periods) is necessary to meet the objective of efficient provision of reactive power?
Q19.	Do you agree with the preliminary cost benefit analysis for the Connection Code option?
Q20.	Do you agree with assessment of advantages/disadvantages? Are there more?

4.6 The market option

- 4.6.1 The market option is a pure market approach that is designed to incentivise efficient investment in reactive power equipment. Under this option there is no regulated PF standard that needs to be maintained at each GXP.
- 4.6.2 The market option consists of a half-hourly market with price discovered through arrangements similar to that used for active power. With this option, half hourly nodal reactive power spot prices would be established by considering offers for the supply of reactive power. Prices would be set *ex-post* based on actual metered demand.
- 4.6.3 The buyers from the market would be DTCs and the sellers would be any third party investor, including Transpower. As an alternative, retailers could be the buyers.
- 4.6.4 A market, for which detailed rules would need to be established, would stand between the buyers and sellers. This is comparable to the structure of the wholesale electricity market that currently exists.
- 4.6.5 A variation on this option is that the market could be either a “gross” or “net” pool. In a gross pool all equipment above a certain size would be required to offer into the market, whether it was connected to transmission or embedded within a distribution network, and GXP purchases would be on a gross basis. Under a net pool only the net reactive flows at each grid connection point would be considered.
- 4.6.6 A major benefit of the market based approach is that (assuming there is sufficient liquidity) the value of reactive power is established in real time, at each GXP, encouraging efficient decision making by consumers and investors.
- 4.6.7 A key point of difference to the other options is that reactive power itself is priced, rather than a recovery of the asset values. This is similar to the active power market where investors make returns from the supply of the product over the longer term.
- 4.6.8 In its most comprehensive form, all reactive power equipment could be covered by the reactive power market (including the supply of reactive power reserve and transmission reactive power requirements). If this was the case then any investment in reactive power equipment would no longer be covered by part F of the Rules at all.

Implementation issues and requirements

- 4.6.9 Substantial implementation issues arise with the need for changes to market systems, co-optimisation of real and reactive power and potential transitional issues such as the status of existing assets, the impact on the TPM and implications on active energy prices and hedge contracts (with co-optimisation). There would also need to be a mechanism to deal with reactive power rentals.
- 4.6.10 The required rule changes would include the following:
- (a) The Connection Code would be amended to remove the PF requirements.
 - (b) Trading arrangements would need to be set out in a similar manner as the rules for real power in part G of the Rules. Part G would need to be substantially amended or a new trading section inserted to take into account the different features of the reactive power market. If required this would include the provisions for the co-optimisation of real and reactive power.
 - (c) The prudential and settlement arrangements under part H of the Rules would also need to be reviewed to ensure they remain appropriate.
 - (d) The TPM would need to be reviewed to specify how any revenue earned by Transpower is to be treated. It may also be necessary to review the GRS, the Interconnection Rules and the BA.
- 4.6.11 A methodology would also need to be established to handle reactive rentals.

Variation

- 4.6.12 A variation to this option is to have a capacity-style market where daily peak demand is priced rather than half-hourly demand. That is, offers would be received for reactive capacity to cover the peak demand periods only. There would be some scope to determining the most appropriate time period over which reactive capacity is priced, i.e. daily, weekly or monthly.
- 4.6.13 The capacity-style market is potentially simpler than the half-hourly market described above because:
- (a) there is the potential for longer time steps;
 - (b) prices could be set on a regional rather than nodal basis; and
 - (c) it would not require co-optimisation with active power. A capacity-style market could also be based on an auction-style format using forecast peak demand (providing some *ex-ante* indication of price) and then actual prices based on metered demand at each GXP.
- 4.6.14 Like the half-hourly market, the capacity market would require:
- (a) the establishment of an auction house which would stand in between all transactions;
 - (b) the establishment of trading arrangements within the Rules; and
 - (c) possibly other rule changes as described for the half-hourly market above.

Advantages and disadvantages

- 4.6.15 The advantages of the market based option are as follows:
- (a) Reactive power is priced every half hour and the full costs are explicitly signalled at each GXP.
 - (b) It provides a price against which investors can invest in equipment.
 - (c) It encourages dynamic and productively efficient solutions.
 - (d) It opens up the provision of reactive power supply to competitive forces and therefore increases the potential of efficient investment to take place.
- 4.6.16 The disadvantages of the market option are:
- (a) The value of the market (in total investment dollars) is relatively low and therefore the efficiency gains from better price discovery and lower cost provision has to be balanced against the high set up and administration costs. The net benefits of such a market are likely to be negative.
 - (b) A change to the electricity market in the way described is fundamental, will have a significant impact on existing market structures and is likely to have significant commercial implications for both buyers and sellers. For example, co-optimisation of real and reactive power prices will change the underlying market price against which all hedge contracts and retail prices are established.

Q21. Do you agree with assessment of advantages/disadvantages of the market based option? Are there more?

Preliminary cost benefit analysis

4.6.17 A summary of the costs and benefits of the market option are:

Criteria		Market option
Principal Objective		✓✓
Costs (set up, administration)		Very high set up, high admin costs from the extensive rule changes required (potentially medium level admin costs for the capacity style variation)
Specific Outcomes (benefits)	Efficiency	✓✓✓
	Risk managed	✓
	Barriers to competition minimised	✓✓
	Incentives for investment	✓✓
	Full costs of production and transport signalled	✓✓✓

	Subject to sustained downward pressure	✓
	Contributes to climate change objectives	✓
Net Benefit		✘

(Assessments range between ✘ and ✓✓✓)

Q22. Do you agree with the preliminary cost benefit analysis for the market option?

4.7 Administered (peak Mvar) charge option

- 4.7.1 The administered charge option is a step towards more regulated solutions than the market option. The administered charge option is primarily concerned with reflecting the longer-term cost of reactive power equipment rather than the value of the reactive power itself. Some of the mechanisms could be similar to the capacity-style variation of the market option but with simpler administration requirements.
- 4.7.2 The administered charge option is based on a reactive power Mvar charge set for each region through a regulatory process under the TPM. All DTCs would have to pay the reactive power charge unless they contracted with Transpower out of the obligation to do so, which would likely only be agreed to by Transpower if the DTC had entered into an equivalence arrangement.
- 4.7.3 There are several alternative mechanisms that could be used to establish the reactive power Mvar charge. For example, the regional requirements for reactive equipment could be forecast by Transpower and then an auction or tender process run for the required quantity of reactive power equipment. A regional charge could then be set such that it recovers the revenue required to meet contracted costs. An example of how this might be implemented is:
- A regional reactive \$/Mvar charge based on the regional definitions in the TPM. The charges would apply to net reactive demand at each GXP. This would be an additional charge component in the TPM.
 - An “as required” tender round would be held, seeking offers for reactive equipment on a regional basis.
 - Charges would be designed to recover the cost of the contracted equipment and based on estimated regional demand. Transpower itself would provide the equipment as a default if lower cost-offers were not received.
 - Any under or overs in the charges would be washed up in the following year, keeping Transpower revenue neutral.
 - Once accepted under the tender process, charges would continue to cover the investment over the life of the asset.

- 4.7.4 An alternative mechanism may be for the reactive power charge to be a function of the long run marginal cost of the next grid connected investments, adjusted for the time period by which the investment is needed. It could be implemented through some form of charge reset made every three to five years to capture changing technology costs and investment requirements.
- 4.7.5 A third alternative is for the quantities of reactive power required to be established through a similar process to the GUP approvals, where the Commission could approve a quantity of reserve equipment to be purchased based on Transpower's submission and the costs charged through to DTCs on a regional basis.
- 4.7.6 An additional simplified variation would be to remove the regional reactive \$/Mvar charge and alter the TPM so that charges are allocated on a peak MVA basis instead of a peak MW basis and better reflect grid usage. For this a mandated minimum PF could be imposed.
- 4.7.7 The trade-off between all these variations is between accuracy of the signal and the level of administration costs.
- 4.7.8 Under this option, all reactive power reserve equipment used for regional dynamic support could also be included in the reactive power charge.

Q23. **Are there any other variations or aspects of the administrated charge option that should be considered in the consultation paper?**

Q24. **Of the variations noted, is there one that is superior to the others?**

Counterparties

- 4.7.9 Transpower and DTCs would be the counterparties. The primary mechanism for charging would be through the TPM.
- 4.7.10 Regional definitions used for the charging would be those specified in the TPM. There would be no need for the PF requirements currently in the Connection Code.

Implementation requirements

- 4.7.11 This option would require a number of rule changes:
- (a) The TPM would need to change to allow for regional charging (and payments) for reactive power demand/supply.
 - (b) Changes to the GRS, section IV of part F of the Rules, the Interconnection Rules and the BA may also be required as discussed under the Connection Code option.
 - (c) The PF requirement would be removed from the Connection Code.
 - (d) Standard contracts would have to be set up to cover investors' costs.

Advantages and disadvantages

- 4.7.12 The following are the advantages for the administered Mvar charge option:
- (a) It increases the incentives for efficient investment in reactive equipment.

- (b) It is much simpler to administer than the market option and may not have the same enforcement issues the Connection Code option has. Therefore, it may have lower administration costs than either of those options.
- (c) It provides a price signal to investors and therefore encourages efficient investment in reactive power equipment.
- (d) It reflects user pays principles as charges would likely be regionally based.
- (e) It integrates with the requirements in part C of the Rules.

4.7.13 The major disadvantage is the numerous rule changes which are likely to be required which:

- (a) impacts negatively on regulatory certainty ; and
- (b) would be a relatively expensive process to set-up and administer.

Q25. Do you agree with assessment of advantages/disadvantages for the administered charge option? Are there more?

Preliminary cost benefit analysis

4.7.14 A summary of the costs and benefits are:

Criteria		Administered charge
Principal Objective		✓✓✓
Costs (set up, administration)		Medium setup cost high admin costs from extensive rule changes
Specific Outcomes (benefits)	Efficiency	✓✓
	Risk managed	✓✓✓
	Barriers to competition minimised	✓✓
	Incentives for investment	✗
	Full costs of production and transport signalled	✓✓
	Subject to sustained downward pressure	✓✓
	Contributes to climate change objectives	✓✓
Net Benefit		✓+

(Assessments range between ✗ and ✓✓✓)

Q26. Do you agree with the preliminary cost benefit analysis for the administered charge option?

4.8 The no obligation option

4.8.1 The no obligation option would have a PF standard as a guide only for connected parties at each GXP. Under this option, Transpower would forecast actual regional requirements for additional reactive power support and then include proposed investments within a GUP as required.

4.8.2 Investment within a connected party’s network would be driven by each company’s own network support requirements.

4.8.3 Investments in reactive power equipment by Transpower are passed through to DTCs under the TPM.

Counterparties

4.8.4 Counterparties would be DTCs and Transpower, but the PF standard would not be contractually enforceable.

Implementation requirements

4.8.5 This option would require the removal of the PF obligations from the Connection Code.

Advantages and disadvantages

4.8.6 The main advantage of the no obligation option is that it is very simple to administer.

4.8.7 The primary disadvantage is that it does not provide any incentive for efficient investment in reactive power by DTCs when the investment is considered an interconnection asset. It depends on Transpower’s willingness and ability to apply the PF standard as guidelines. However, investment in grid-connected reactive power equipment is at least covered by the application of the GIT, so only investments with a positive net benefit to consumers would be approved.

Q27. Do you agree with assessment of advantages/disadvantages of the no obligation option? Are there more?

Preliminary cost benefit analysis

4.8.8 A summary of the costs and benefits is:

Criteria	No Obligation
Principal Objective	✓

Costs (set up, administration)		Low setup cost, low admin cost
Specific Outcomes (benefits)	Efficiency	✘
	Risk managed	✓
	Barriers to competition minimised	✘
	Incentives for investment	✓
	Full costs of production and transport signalled	✘
	Subject to sustained downward pressure	✓
	Contributes to climate change objectives	✓
Net Benefit		✘

(Assessments range between ✘ and ✓✓✓)

Q28. Do you agree with the preliminary cost benefit analysis of the no obligation option?

4.9 Assessment Summary

The following table summaries the assessment of the options.

Criteria		Connection Code	Market option	Administered charge	No Obligation
Principal Objective		✓✓✓	✓✓	✓✓	✓
Costs (set up, administration)		Low setup costs, Medium admin costs	Very high set up, very high admin costs (potentially medium admin costs for capacity-style variation)	Medium setup cost Medium to low admin costs	Low setup cost, low admin cost
Specific Outcomes (benefits)	Efficiency	✓✓	✓✓✓	✓✓	✘
	Risk managed	✓✓✓	✓	✓✓✓	✓✓✓
	Barriers to competition minimised	✓	✓✓	✓✓	✘
	Incentives for	✓✓	✓✓	✓✓	✘

Criteria		Connection Code	Market option	Administered charge	No Obligation
	investment				
	Full costs of production and transport signalled	✓✓	✓✓✓	✓✓	✗
	Subject to sustained downward pressure	✓	✓	✓✓	✓
	Contributes to climate change objectives	✓	✓	✓	✓
Net Benefit		✓✓+	✗	✓+	✗

5. Process and timetable

5.1.1 The following preliminary process and timetable sets out the required steps for completing consultation on the options and includes the process for any potential changes to the Rules that may be required due to the adopted solution:

5.1.2 The proposed steps include:

- (a) *publishing this Issues Paper* to seek comment on the range of options available to address the efficient supply of reactive power, including seeking suggestions on any other options not considered in the Issues Paper; ;
- (b) *considering responses to the Issues Paper*
- (c) *the Commission then deciding on a preferred option.* If the preferred option requires changes to:
 - (i) the TPM, the Commission would then commence the process of reviewing the Guidelines for the TPM by releasing an issues paper as required by rule 4 of section IV of part F, setting out the process to be followed in revising the TPM and proposed amendments to the guidelines for the TPM. The steps under rules 5-8 of section IV of part F would then follow;
 - (ii) the Connection Code, commencing the process of reviewing the Connection Code under rule 3.3.10 of section II of part F. This commences with the Commission requiring Transpower to provide a revised Connection Code under rule 3.3.2 of section II of part F;
 - (iii) the BA, commencing the process for reviewing the BA under rule 4 of section II of part F. This commences with the Commission publishing a revised BA for consultation;
- (d) *publishing a consultation paper* on any other proposed rule changes (including changes to the BA) that would represent the options and any

new options considered reasonably practicable that have arisen in response to the Issues Paper or otherwise (**Consultation Paper**). Under the table below, this Consultation Paper is incorporated with steps in the processes for reviewing the TPM and the Connection Code. Cost benefit analysis would be presented, and if possible, it would include quantitative as well as qualitative analysis. The Commission would present a preferred option and also respond to the first round of submissions. A presentation and workshop may be held to assist submitters in formulating their views prior to the closing date for submissions;

- (e) *publishing (a) decision paper(s)* on the supply of reactive power (**Decision Paper(s)**) including the analysis required by section 172F of the Act and, including response to submissions on the Consultation Paper; and
- (f) *providing analysis and recommendation to the Minister of Energy* for any rule changes required to implement the preferred option for the supply of reactive power.

5.1.3 The following is an indicative timetable, but is subject to change.

Date	Milestone
Late September 2008	Issues Paper published
24 October 2008	Closing date for submissions on Issues Paper
End December 2008	Publish Consultation Paper
Late January 2009	Presentation and workshop
Mid February 2009	Closing date for submission on Consultation Paper
Early April 2009 (may extend to August 2009)	Publish Decision Paper (a number of papers may be required if extensive rule changes are required)
April 2009 – September 2009	Recommendation to the Minister (if required)

Q29. **Do you agree with the proposed process? If not, do you have any suggestions to improve the process?**

5.1.4 Alternatively if the Commission decided on a preferred option that did not require any rule changes then it could proceed to develop the necessary policy documents to provide guidance to Transpower and DTCs. The table below outlines a proposed draft timetable for the provision of such policy guidance for Transpower and DTCs.

Date	Milestone
End December 2008	Consultation paper published to pursue option that did not require any rule changes
February 2009	Public workshop on level of guidance required by market participants
January – March 2009	Discussions with Transpower
End April 2009	Publish draft policy guidance
End May 2009	Submissions close on draft policy guidance
End June 2009	Publish policy guidance

Q30. Do you agree with the proposed process? If not, do you have any suggestions to improve the process?

Appendix 1 – List of Questions

- Q1. Do you agree that it is reasonable to decide the purpose of an investment at the time the charges are fixed under the TPM?
- Q2. Do you agree that the summary of the Commission's process is correct?
- Q3. Do submitters consider that this a practicable and workable interpretation of the PF requirement? Do submitters consider that the Commission has to provide further guidance (see related question Q30)
- Q4. Do you agree with Commission's view on the measurement issue?
- Q5. Do you consider that it is reasonable to expect and accept minor deviations within the half-hour measurement period or over a longer period?
- Q6. Do you have other concerns about the PF requirement?
- Q7. Do you agree with assessment of Part C integration issues? Are there more?
- Q8. Do you agree with assessment of system operation issues? Are there more?
- Q9. Do you agree that the options should cover GXP demand for reactive power only?
- Q10. Do you consider there are other reasonably practicable options [*to the four covered*]?
- Q11. Are there other variations [*to the options set out*] that the Commission should consider in more detail?
- Q12. Do you consider that a clarification of the TPM definition of connection assets is required?
- Q13. Do you consider that any of the GRS, section III of Part F of the Rules, the Interconnection Rules or the BA would also need to be reviewed?
- Q14. Do you consider that one of the above potential variations for the definition of the PF standard is superior? If so, why? Are there other options?
- Q15. Do you consider that a pragmatic approach to assessing contractual compliance is appropriate (see related questions **Q3** and **Q5**)?
- Q16. Do you consider that Transpower and the Commission should develop a compliance policy?
- Q17. Do you consider that an appropriately worded compliance policy would help remove any doubt as to how the enforcement of unity PF obligation would impact on a GUP?
- Q18. Do you agree that the Connection Code option (a PF of unity in the selected regions and periods) is necessary to meet the objective of efficient provision of reactive power?
- Q19. Do you agree with the preliminary cost benefit analysis for the Connection Code option?

- Q20. Do you agree with assessment of advantages/disadvantages? Are there more?
- Q21. Do you agree with assessment of advantages/disadvantages of the market based option? Are there more?
- Q22. Do you agree with the preliminary cost benefit analysis for the market option?
- Q23. Are there any other variations or aspects of the administrated charge option that should be considered in the consultation paper?
- Q24. Of the variations noted, is there one that is superior to the others?
- Q25. Do you agree with assessment of advantages/disadvantages for the administered charge option? Are there more?
- Q26. Do you agree with the preliminary cost benefit analysis for the administered charge option?
- Q27. Do you agree with assessment of advantages/disadvantages of the no obligation option? Are there more?
- Q28. Do you agree with the preliminary cost benefit analysis of the no obligation option?
- Q29. Do you agree with the proposed process? If not, do you have any suggestions to improve the process?
- Q30. Do you agree with the proposed process? If not, do you have any suggestions to improve the process?

Appendix 2 – Advice on measurement problems