Appendix 5

Static Reactive Power Compensation

Prepared by Electricity Commission

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Executive summary

This appendix reconsiders static reactive power compensation after consideration of the responses to the Commission's consultation paper (*Transmission Pricing Review: High-level options - October 2009*)[1] (**stage 1 consultation paper**).

The stage 1 consultation paper set out the relevant matters with respect to a review of transmission pricing, including a discussion on the most appropriate approach to allocating the costs of static reactive compensation consistent with Pricing Principles and other relevant considerations.

This appendix continues the discussion and analysis on the issue of static reactive compensation and seeks further comment from interested parties on specific issues addressed herein.

The Commission considers there are benefits from a more targeted approach to the allocation of the costs of static reactive compensation as there is predicted to be a substantial requirement for reactive power investment in the UNI and USI for the next 10-15 years.

A proportion of the static reactive power investment in these regions is required to support the reactive power demand of connected parties. The cost allocation of this investment needs to be addressed, to ensure participants make the most efficient investment decisions. In some circumstances, static reactive power investment may be more efficient if it was to be located within distribution networks, as opposed to the transmission network. After considering submissions on the stage 1consultation paper (and previous submissions on an issues paper entitled "Options for ensuring efficient reactive power investment" issued on 26 September 2008 (**reactive power issues paper**) [2] on static reactive compensation), the Commission has developed three alternative approaches to discuss with participants:

- Option 1 ("Amended Status Quo Option"): amending the current standard in the Connection Code for the USI and UNI regions to unity or leading power factor and retaining this standard as a basis for determining the allocation of costs for static reactive power investment; and relying on the parties to the bilateral contractual framework to make arrangements where the strict requirements in the Connection Code are not appropriate for particular points of service (this approach also applies to many other matters in addition to the *pf* requirements);
- Option 2 ("Connection Asset Definition Option"): widening the definition of "connection asset" to include new static reactive power investments to the extent that they deliver

[1] Available at http://www.electricitycommission.govt.nz/pdfs/opdev/mdp/consultation/TPR-consultation.pdf

[2] Issues Paper —options for ensuring efficient reactive power investment 26 September 2008 (Issues Paper) Available at http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/reactive-power-investment/issuespaper.pdf and

reactive power to customers in a region; and relaxing the fallback *pf* requirement in the Connection Code;

- Option 3 (“kvar Charge”): determine an appropriate kvar charge to incentivise more cost effective investment in static reactive support, either in the transmission network or in the distribution network in each case, regardless of the power factor at the Grid Exit Point (**GXP**) in question.

Contents

1. Introduction

1.1 Purpose of this appendix

1.1.1 This appendix reconsiders static reactive power compensation after consideration of the responses to the Commission's consultation paper (*Transmission Pricing Review: High-level options - October 2009*) (**stage 1 consultation paper**) and the earlier issues paper entitled "Options for ensuring efficient reactive power investment" issued on 26 September 2008 (**reactive power** i**ssues paper)**.

1.1.2 This appendix sets out the following.

(a) The cost allocation issue of the static reactive support required by both remote loads and low power factor loads.

(b) Current allocation of static reactive power costs..

(c) The consideration of static reactive power compensation in the stage 1 consultation paper and in the reactive power issues paper.

(d) Submitter response to the consultation paper and the Commission response.

(e) Options for cost allocation of static reactive support costs.

1.1.3 The Commission's objectives are to incentivise efficient investment in static reactive power supply; and to ensure that the causers of those investments pay a proportionate share of them.

1.1.4 The Commission considers that the transmission agreement counterparties are best placed to determine what the best investment decisions are. It is seeking a way to ensure that participants make the most efficient investment decisions with regard to investment in static reactive power by allowing for the participants to choose whether they invest, or Transpower invests (and they pay their share of the cost of the Transpower investment).

2. Background

2.1 Background and context

2.1.1 Reactive support for the transmission system is installed in a region to carry out the function of voltage support. Voltages in regions can sometimes drop under contingency conditions when the transmission system is heavily loaded. This is a common problem when the demand is located remotely from the majority of generation (for example in the Upper North Island (**UNI**) and Upper South Island (**USI**) regions).

2.1.2 Voltage instability following an outage may result when these voltage constrained regions have insufficient reactive support to "prop up" the local voltages, and as a consequence, in extreme circumstances, the voltage may collapse with region-wide load tripping being the result. As a consequence, in order to maintain grid security, Transpower has to ensure that sufficient reactive compensation is always available to meet demand, regardless of whether the reactive demand is within or external to the transmission system.

2.1.3 When loads in the region operate with low power factors without this being compensated for locally, reactive power is drawn from the grid. Low power factor loads create further reactive losses in the **GXP** supply transformers and connected transmission circuits and so require a greater level of reactive support from the grid when compared with those loads that operate at or near unity power factor. As a consequence this may result in transmission investment being advanced due to the increased line current flows or for voltage stability reasons.

2.1.4 There is predicted to be a substantial requirement for reactive power investment in the UNI and USI regions for the next 10-15 years[3]. A proportion of the static reactive power investment in these regions is required to support the reactive power demand of designated transmission customers (**DTCs**). The cost allocation of this investment needs to be addressed, to enable any cost savings to be made from incentivising the most efficient investment. In some circumstances, static reactive power investment may be more efficient if it was to be located within distribution networks, as opposed to the transmission network.

2.1.5 The Commission considers that potential cost savings could be gained through:

(a) incentivising the least cost <u>static</u> reactive compensation investment; and

(b) avoiding the cost of using expensive <u>dynamic</u> reactive compensation to address static reactive compensation issues (see paragraph 2.3).

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3 Transpower, Annual Planning Report 2010

2.1.6 The following table shows the expected investments in static/dynamic reactive compensation for the next 10 years. The information in this table has been extracted from Transpower's 2010 Annual Planning Report.

Description	Mvars	Static / Dynamic	Year	Comments
Otahuhu 220 kV	2 x 100 Mvars	S	2010	Committed
Bunnythorpe 220 kV and Haywards 220 kV	??	S + D	2012 to 2020	Possible economic investment
Voltage stability Upper South Island	??	S + D	from 2017	Possible reliability investment
Maungatapere 110 kV	2 x 30 Mvars	S	from 2016	Could change dependent on UNI reactive
Kaitaia 33 kV	10 Mvar more	S	from 2016	Could change dependent on UNI reactive
Kaikohe capacitor replacement	??	S	from 2016	Could change dependent on UNI reactive
Waihou and/or Waikino 110 kV	2 x 20 Mvars	S	~ 2012	Low voltage on Waihou - Waikino - Kopu spur following loss of 110 kV Hamilton - Waihou circuit
Mt Maunganui, Tauranga or Kaitimako 110 kV - additional static reactive support	??	S	from 2016	Low voltages at Te Matai, Mt Maunganui & Tauranga during 220 kV contingency
Hawera	~ 40 Mvar	S + D	2012 to 2015	Low voltage at Hawera following loss of 110 kV Hawera - Stratford circuit
Paraparaumu 33 kV	??	S	~ 2012	Low voltage at Paraparaumu during winter peak load. One of many solutions
Blenheim 33 kV capacitor replacement	??	S	~ 2013 to 2017	Part of USI voltage issue
Stoke 11 kV capacitor replacement	??	S	~ 2013 to 2017	Part of USI voltage issue
Motupipi 33 kV and/or Motueka 11 kV	??	S	TBA	Golden Bay low voltage issue
Dobson 11 kV reactive support at transformer tertiary windings	??	S	~ 2012	West Coast and Hokitika low voltage issues
Oamaru 33 kV	35 Mvars	S	from 2010 to 2013	20 Mvars in 2010, increasing to 35 Mvars in 2013. Addresses low voltage at Oamaru.
Studholme 11 kV	20 Mvars	S	~ 2013	Address low voltage at Studholme.

Description	Mvars	Static / Dynamic	Year	Comments
Balclutha 110 kV	??	S	~ 2012 to 2015	Low voltage at Balclutha following loss of 110 kV cct. Part of LSI Reliability project.
Gore 110 kV	??	S	~ 2012 to 2015	Low voltage at Gore. Part of LSI Reliability project.

2.1.7 Previous analysis[4] by the Commission indicated that if demand power factor correction is required to support transmission then it is more economic, from a net benefits perspective, to correct power factor on the low voltage (**LV**) distribution network rather than the high voltage (**HV**) transmission grid. This is because the lower cost of HV capacitors is outweighed by the reduced losses in the distribution network associated with LV capacitors located close to reactive loads.

2.1.8 The results illustrated in the graph[5] below suggested that there is a net economic benefit in correcting LV power factor up to about 0.9975 lagging (where the benefit associated with HV, as indicated by the red line, and LV correction, the green line, are equal). For expediency this analysis ignored the further economic benefits associated with both grid capacity (through increased voltage stability limits[6]) or distribution company asset capacity increases[7].

2.1.9 The analysis indicates the preferred location of static reactive compensation to be on the LV distribution network rather than the HV side for power factors below 0.9975 lagging. As distribution companies improve their power factor over time, the analysis suggests that benefits of LV correction reduce and at some point, in this case when the power factor reaches 0.9975, it is more economic to install, HV power factor correction on the HV network.

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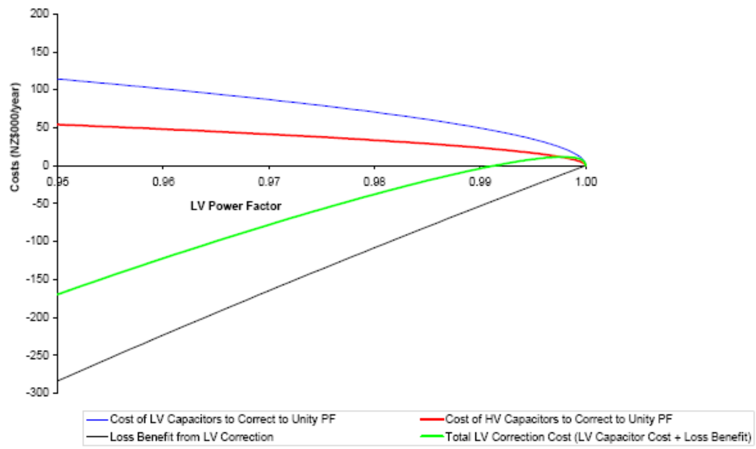
4 http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/outage/Appendix4-Correction-Costs.pdf

5 Shown as Figure 2 from the analysis referred to in footnote 4.

6 The increase in transmission voltage stability limit is not proportional to power factor (as is the case for thermal limits in distribution networks) but proportional to reactive power flow. For example, in the case of the USI, an increase from 0.98 lagging to unity power factor improves transmission voltage stability limits by over 10%, yet thermal limits are increased by only 2%.

7 Historical evidence in attachment 1 illustrates that most upper island distribution companies are improving their power factor during peak demand periods. This may indicate increasing economic benefits for distribution companies to increase network capacity by improving power factor (or otherwise uptake of more underground cabling). An increase from 0.95 to 0.99 lagging gives a 4% asset capacity increase which, in a suburb with 1% growth, would represent a deferral on distribution transmission investment by 4 years.

Figure 2. Annualized Costs for HV and LV Unity Power Correction (To Supply 100 MW Peak Demand)



2.1.10 In the previous consultation, participants were asked to comment on the analysis in figure 2. Orion made a significant comment that the analysis would be overstating the benefit of the reduction in losses in the LV distribution network as it was based on a network primarily consisting of overhead lines. Where there was significant underground cabling the losses would not be as great and therefore the benefits from investment on the LV network would be less.

2.1.11 Expected investment in dynamic reactive compensation is a more significant cost. It is more difficult to calculate the benefits of deferring or avoiding dynamic reactive compensation by improving power factor. Using the Auckland region example where dynamic reactive compensation investment is planned(see paragraphs 2.3.7 and 2.3.8), the deferment value is around $10 million/pa.

2.2 Current allocation of costs

2.2.1 The current requirements are intended to incentivise efficient investment in static reactive power, and to ensure that the causers of those investments pay a proportionate share of them. The approach adopted was based on the consideration that the transmission agreement counterparties are best placed to determine what the best investment decisions are. Ideally, a **DTC** should be able to choose between:

(a) investing in their own voltage support equipment to reduce losses and improve voltage performance; or

(b) contracting with Transpower to invest in new assets under a "new investment contract" (**NIC**) and/or for non-compliance with the Connection Code; or

(c) not contracting with Transpower but bearing the cost of their drawing reactive power (i.e. choosing to non-comply with the power factor requirement).

2.2.2 The Commission sought to achieve this allocation by means of a provision in the Connection Code requiring a unity power factor at times of high load in the relevant region.

2.2.3 The purpose of the Connection Code is to set out the technical requirements and standards that DTCs must meet in order to be connected to the grid and with which Transpower must also comply. The Connection Code forms part of any transmission agreement between Transpower and a DTC, and enforcement of any provisions in the Connection Code is therefore a bilateral contractual matter between Transpower and the relevant DTC.

2.2.4 At the time the framework[8] governing the relationship between Transpower and DTCs was developed, industry feedback indicated a strong preference for a bilateral contractual framework with a direct relationship between DTCs and Transpower as grid owner where practical.

2.2.5 The Connection Code requires that connected parties in the UNI and USI regions must maintain a power factor of unity during regional coincident peak demand periods (**RCPD**). Unity power factor occurs when the flow of reactive power across the GXP is zero.

2.2.6 If connected parties do not comply with the requirements of the Connection Code then they must either seek a non-compliance agreement (as set out in appendix A of the Connection Code with Transpower or face action against them by Transpower for breach of contract.

2.2.7 To avoid such non-compliance connected parties would need to provide reactive power to balance reactive power consumption by their assets and end users within in their network or ensure reactive power is provided by end users at their own cost.

2.2.8 As this issue primarily relates to ensuring sufficient investment in static reactive compensation either within or external to the transmission network Transpower is expected to assess the potential for non-compliance at the most critical times of grid usage when planning for investment in transmission assets.

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8 The framework encompasses the Benchmark Transmission Agreement, interconnection rules for the use of interconnection assets, Connection Code, Outage Protocol and the transmission pricing methodology (**TPM**).

2.2.9 In the UNI and USI this would be at periods of regional peak demand as at other times reactive power drawn from the network makes little difference to the performance of the network.

2.2.10 Attachment 1 provides an historical analysis of reactive power demand at peak times from the transmission network between 2001 and 2009 by the relevant distribution line business in the UNI and USI.

2.2.11 In some circumstances it will be more cost effective for DTCs to continue to draw reactive power from the transmission grid at peak times. Accordingly it is important that DTCs face appropriate incentives by way of transmission cost allocation to make an efficient trade-off between either investing in their own static reactive compensation arrangements or drawing reactive power from the transmission grid.

2.2.12 Currently, once Transpower identifies that static reactive support is necessary in a region, it seeks approval for an investment for a new interconnection asset. This static reactive support, if approved by passing the grid investment test (**GIT**) process and its future replacement[9], is usually placed somewhere in the transmission grid close to load.

2.2.13 If the static reactive support assets are interconnection assets as defined by the current TPM, the cost of these assets is recovered from all load by means of a “postage stamped” charge. This means that the region that causes the voltage issue does not necessarily incur the full cost of the investment (i.e. there is no penalty for the load that necessitates reactive power supply from the grid).

2.2.14 Alternatively, if the static reactive support is deemed to be a connection asset, the cost of this is recoverable from the relevant DTC. Where a transmission customer will not agree to new investment contract for the proposed connection asset, Transpower is able to use the breach of the Connection Code by the DTC to require the breaching party to enter into power factor non-compliance agreements to underwrite the costs of such connection assets.

[9] The Electricity Industry Bill proposes to transfer the responsibility for approving all transmission investments to the Commerce Commission and that the GIT be replaced by an input methodology developed by the Commerce Commission. Although the GIT may not remain in its current form under the new arrangements, some sort of net benefit test for the assessment of transmission investment is likely to replace it. For the purposes of this paper, the net benefit test will continue to be referred to as the GIT.

2.2.15 The GIT process may result in the regulator not approving the investment because an alternative distribution investment is more economic or Transpower may identify that the static reactive support is better placed in the distribution network if it is more economic to do so.

Pass through of lines businesses' costs

2.2.16 It has become apparent during the recent consultation process that some parties consider that the distribution companies may be unable to recover the costs of investments if they choose to invest rather than Transpower. There are concerns the Commerce Commission will not allow a deviation from the price path threshold to enable distributors to obtain cost recovery for this type of investment, even if it is obvious that this is the most economic outcome.

2.2.17 The Commission has discussed this with the Commerce Commission and industry parties and sees no reason why distribution companies should not be able to recover these costs under Part 4 of the Commerce Act 1986 (**Commerce Act**) where it could be shown that the cost is less than the alternative (pass-through) transmission investment

2.2.18 The Commission notes that the 2009 amendments to the Commerce Act will assist in the recovery of costs incurred directly by distribution companies themselves by:

(a) providing that consumer-owned electricity lines services are only subject to information disclosure regulation and not default/customised price-quality regulation (section 54G);

(b) adding a new section to the Commerce Act (section 54Q) requiring the Commerce Commission to actively promote incentives for lines businesses to invest in energy efficient investments (and the Commission considers that reactive power sources are likely to fall into this category of investment); and

(c) allowing for customised price-quality paths for those electricity lines services subject to price-quality regulation.

Section 54Q

2.2.19 Section 54Q of the Act, which came into force on 1 April 2009, has the greatest potential to provide incentives for lines businesses to make energy efficient investments. It provides that the Commerce Commission must:

> "*promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying* [the Default/Customised Regime, and the rest of Part 4,] *in relation to electricity lines services*."

2.2.20 The Commission expects that section 54Q will produce incentives for lines businesses to make energy efficient investments. While this will depend on the ability of the Commerce Commission to create mechanisms that encourage energy efficient investment decisions, the inclusion of section 54Q suggests an increased focus for distribution companies that are subject to the default/customised regime on investing in energy efficient assets.

2.2.21 The economic analysis provided by the Commission in this paper indicates that one of the main economic benefits from installation of static reactive power equipment is in the reduction of transmission and distribution losses.

Proposed changes to the treatment of transmission charges

2.2.22 It is a regulatory anomaly[10] that distribution companies see no benefit in responding to minimise Transpower charges by making their own investments as Transpower charges can be "passed through". However, the Commerce Commission is proposing[11] to address this regulatory anomaly by allowing those distribution companies subject to the price quality regime (non-exempt EDBs) to retain avoided transmission charges where it can be demonstrated that the avoided charge is a *"result of reducing the overall cost of the supply of electricity line services"*[12].

2.3 System Operator recovery of dynamic reactive support costs in the UNI

2.3.1 In the UNI region, specifically for the Auckland and North Auckland regions, there is another cost allocation process quite distinct from the part F cost recovery and allocation mechanisms. This is for the provision of dynamic reactive support procured by the SO. This arrangement also allocates the costs of providing reactive power from the transmission grid, signalling costs whenever power factor is less than unity for reactive demand from the grid.

2.3.2 While this mechanism is intended to recover the SO costs of securing dynamic reactive compensation, the assets provided for this purpose also effectively provide static reactive compensation to the DTCs due to the means by which the charges are determined.

[10] This issue has potential far beyond the scope of static reactive power investment and encompasses incentives in relation to all connection assets paid for by distribution lines business, roughly 20% of Transpower's asset based revenue requirement.

[11] http://www.comcom.govt.nz/assets/Pan-Industry/Input-Methodologies/Draft-Determinations/Draft-Commerce-Act-Electricity-Distribution-Services-Input-Methodologies-Determination-2-July-20.pdf

[12] Ibid - Clause 3.2.4(5))

2.3.3 Up to this point in time the SO has been contracting with Mighty River Power (MRP) and Contact Energy, via ancillary services contracts, to make synchronous dynamic reactive support plant available at Marsden and Otahuhu respectively, to ensure that voltage stability limits are maintained in the region. While dynamic plant like this are usually reserved for issues related to dynamic voltage collapse, it is possible that the SO could effectively also use this plant to compensate for reactive power drawn by the DTCs.

2.3.4 This would be inefficient as the costs associated with these plants are closely related to the replacement cost of modern dynamic reactive support devices, namely static var compensators (SVCs), which are much more expensive than the static capacitors which could be better used to compensate static reactive off-take by DTCs.

2.3.5 Under the Part C arrangements the costs associated with the dynamic reactive plant are allocated based on the local distribution company nominated predicted peak kvar for a year, and a penalty rate, should this be exceeded. Potentially this over signals reactive power compensation costs and could lead to uneconomic outcomes. It is also undesirable if costly dynamic plant is used to perform static compensation duties.

2.3.6 A long term view of such dynamic reactive compensation costs might involve investment by the Grid Owner to efficiently reduce these costs. Transmission investments to reduce these costs would be subject to the GIT and recovered as transmission charges under Part F, rather than under Part C.

2.3.7 Transpower is taking this longer term view and has investigated the need for dynamic reactive support in the UNI.

2.3.8 Transpower has submitted a Grid Upgrade Plan (GUP) that includes a package of investments including two static synchronous compensators (STATCOMs), a reactive power controller to control these devices, monitoring equipment, software upgrades and load control initiatives. These investments (in conjunction with the Otahuhu to Whakamaru 400 kV project) will relieve the existing voltage stability issues in the UNI until 2015. Although more reactive support will be needed in the future, Transpower have sought approval only for the investment required until 2015.

2.3.9 Transpower is studying options for the period beyond 2015, but as generation may emerge in the meantime, this investment may be able to be deferred.

2.3.10 Arguably where grid users cause dynamic reactive power costs they should also face these costs[13]. At this stage it appears impracticable to define connected

[13] Induction motor loads have undesirable dynamic reactive power characteristics, as when voltages fall they increase reactive demand and in some circumstances draw up to six times rated current in low voltage

demand parties dynamic reactive response obligations and so the Commission is considering signalling static reactive compensation costs.

situations. Similar to some types of wind generation, dynamic reactive compensation close to the motor load can be more efficient than at grid voltage levels.

3. Considerations of static reactive power compensation

3.1 The reactive power issues paper (2008)

3.1.1 The Benchmark Agreement which came into force on 1 April 2008, requires that from April 2010 connected parties in the UNI and USI maintain unity power factor[14].

3.1.2 Following completion of the Benchmark Agreement a number of industry parties expressed concern regarding the practicality of complying with the unity power factor requirements of the Benchmark Agreement. Accordingly the Commission published the reactive power issues paper and received submissions for 16 parties in response to 30 questions raised by the Commission.

3.1.3 Submissions at that time were considered by the Commission by broadly grouping the issues into five areas:

(a) *Problem definition*—submitters asked what the Commission is seeking to achieve from the power factor requirement in the UNI and USI.

(b) *Status quo*—the approach taken in the status quo option;

(c) *Temporary problem* —submitters' views on the temporary nature of the problem being addressed;

(d) *Passing costs through*—the integration of what the Commission has proposed with the Commerce Commission's price path threshold for lines businesses; and

(e) *Other general issues*—regarding insufficient time to build new assets to enable compliance and the ability to seek exemption from the Connection Code.

3.1.4 The Commission's consideration of submissions in response to the reactive power issues paper concluded that:

(a) *Problem definition*—Many submitters had misunderstood the purpose of the Connection Code power factor obligation.

(b) *Status quo*—Widespread concern existed regarding the application of the unity power factor obligation and the ability to establish non-compliance arrangements with Transpower. Many submitters indicated a preference for an administered charge for kvar consumption.

[14] This requirement can be found in clause 4.4(a)(2)(i) of the Connection Code, schedule 8 of the Benchmark Agreement.

(c) *Temporary problem*—Those submitters who maintained that it was a temporary problem were not able to support their view. The analysis that it is a temporary problem is inconsistent with analysis by both the Commission and Transpower.

(d) *Passing costs through*—Distribution companies may have problems recovering costs for efficient investment in their own networks while perversely being able to simply pass through Transpower costs for inefficient investment. This issue needed to be taken up with the Commerce Commission.

(e) *Other general issues*— It was not possible for the Commission to grant exemptions from the requirements of the Connection Code as the agreement applied between Transpower and the connected party as a bilateral arrangement. Transpower and the connected party should seek to negotiate non-compliance agreements if needed.

3.1.5 Following further consideration of this issue the Commission decided that instead of arranging further industry briefings and consultation papers it would be more effective to engage directly with the affected parties to enable a better understanding of their concerns. To this end a small working group facilitated by an external party was established[15].

3.1.6 During this time the Commission has also been investigating changes to the existing arrangements. Earlier discussion (April 2008) with the Transmission Advisory Group indicated a preference for use of simple pricing mechanisms. Accordingly in the stage 1 consultation paper, the Commission asked for submitters' views on whether this issue should be included within the transmission pricing review (review).

3.2 The stage 1 consultation paper (October 2009)

3.2.1 As noted in the stage 1 consultation paper the Commission's objective in respect of this issue is to incentivise efficient investment in static reactive power supply equipment by ensuring that causers pay for reactive power consumed. Potentially the status quo, relying solely on the power factor requirements of the Connection Code, may not provide sufficient prescription to easily support the allocation of costs to causers required as part of non-compliance agreements. In the stage 1 consultation paper the Commission outlined the option of using the TPM to allocate the costs of new and existing static reactive power assets[16].

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[15] This work is reported at http://www.electricitycommission.govt.nz/pdfs/advisorygroups/iag/11feb10/pres-powerfactor.pdf

[16] Ideally this allocation would be between that required for transmission purposes and that required to meet connected parties coincident demand for reactive power.

3.2.2 In March 2010 the Commission published its summary of submissions on the High level option paper[17].

3.2.3 Submitters were generally supportive of changes to the way static reactive power costs are allocated, but were split on whether it is appropriate for this to be considered as part of the review.

3.2.4 For those submitters who considered that it was not appropriate to consider reactive power compensation as part of the review, they submitted that it was not a priority at present, or it was worthy of separate consultation in order to undertake a proper analysis of the costs and benefits and to consider all options.

3.2.5 Some submitters made specific comments about how static reactive power costs should be treated.

(a) Lead times must be realistic to allow participants to design, cost and install new static power-factor correction assets (Northpower).

(b) Price signals may be preferable to an allocation methodology. A peak period (RCPD) kvar price component could be introduced that matches the forward price of grid reactive support so connected parties could have the options to respond to that price (Orion).

(c) It may be better that reactive power components are just treated as transmission assets (Powerco).

(d) A development of a pricing mechanism, supplemented by realistic minimum power factor requirements could encourage economically efficient investment in reactive compensation equipment (Vector).

(e) The most appropriate means by which to allocate transmission and non-transmission voltage support costs should be investigated, noting that pricing incentives generally offer more flexibility than regulated requirements (Transpower).

(f) Allocation of reactive power costs via the TPM will make costs more visible to participants. Costs should be regionalised to the extent possible (Todd Energy).

3.3 Commission considerations

3.3.1 In the event that Transpower is required to develop a revised TPM in response to revised Transmission Pricing Guidelines provided by the Commission extensive work will be required. There are potential scope and scale efficiencies in development of a TPM which deals with both real and reactive power aspects of

[17] Available at: http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpr/TPR-summary-submissions.pdf

grid usage. Reactive power charges would also need to have a cost basis and this would need to be developed in common with charges for connection assets to ensure consistency.

3.3.2 At this stage the Commission is considering three options: first a slightly amended status quo where there is no TPM for static reactive power supply and secondly two approaches where the TPM provides a defined basis for cost recovery from users.

4. Options for Static Reactive Power Compensation

4.1 Introduction

4.1.1 After considering submissions on the stage 1 consultation paper (and previous submissions on the reactive power issues paper), the Commission has developed three alternative approaches to discuss with participants:

(a) **Option 1 (Amended Status Quo Option):** amending the current standard in the Connection Code for the USI and UNI regions to unity or *leading power factor* and retaining this standard as a basis for determining the allocation of costs for static reactive power investment. This arrangement relies on the parties to the bilateral contractual framework to make arrangements where the strict requirements in the Connection Code are not appropriate for particular points of service (this approach also applies to many other matters in addition to the power factor requirements);

(b) **Option 2 ("Connection Asset Definition Option"):** widening the definition of "connection asset" to include new static reactive power investments to the extent that they deliver reactive power to customers in a region; and relaxing the fallback power factor requirement in the Connection Code;

(c) **Option 3 ("kvar Charge"):** determine an appropriate kvar charge to incentivise more cost effective investment in static reactive support, either in the transmission network or in the distribution network in each case, regardless of the power factor at the GXP in question.

4.2 Option 1 – amended status quo

4.2.1 Following submissions on the stage 1 consultation paper, and submissions on the earlier reactive power issues paper, the Commission considers that while the status quo remains an option, it is a less practicable option than an amended status quo option.

4.2.2 The amended status quo would involve continuing to rely on negotiated non-compliance agreements between Transpower and the affected parties but would involve a change to the current power factor standard in the Connection Code for the UNI and USI regions to a unity *or* leading power factor.

4.2.3 The power factor requirements in the Connection Code are intended to form the basis of cost allocation. This section explains the Commission's reasoning in proposing unity (in the constrained UNI and USI regions) as the base from which to measure the cost allocation.

Analogy with Part C of the Rules

4.2.4 As an analogy, the Commission notes that while Part C of the Electricity Governance Rules 2003 (**Rules**) (which relates to common quality) does not require a minimum power factor for grid off-take customers in the way that the Connection Code does, the charging regime in this part does effectively use unity power factor as a reference point in a manner comparable to the contractual compliance regime contemplated for the status quo option.

4.2.5 Part C provides for the SO, in those instances where it is unable to manage grid voltage using a combination of generator capability and grid connected reactive plant, to purchase voltage support ancillary services.

4.2.6 Part C charges for these voltage support ancillary services are based on total peak kvar demand as measured at the normally contiguous electrical busbar of a particular voltage where Transpower as a grid owner has agreed to provide services to one or more designated transmission customers (**point of service**). Given this methodology, off-take customers receive a price signal in proportion to the peak reactive demand that would have to be supplied from the grid to correct customer off-take power factor to unity.

Bilateral matter

4.2.7 The Connection Code forms part of any transmission agreement between Transpower and a DTC, and enforcement of any provisions in the Connection Code is therefore a bilateral contractual matter between Transpower and the relevant DTC.

4.2.8 The purpose of the Connection Code is to set out the technical requirements and standards that DTCs must meet in order to be connected to the grid and with which Transpower must also comply. However, the Connection Code can be departed from through negotiated agreements between Transpower and the DTC. If there is a cost involved in that departure, the allocation of that cost can also be managed through a bilateral negotiation between Transpower and the DTC.

4.2.9 While the cost allocation is not prescribed, making DTCs responsible in the first instance for meeting the power factor obligation ensures that the DTCs face some cost for the reactive power demand that is made at the point of service.

DTCs' choice

4.2.10 The amended status quo option allows DTCs to choose between:

(a) investing in their own voltage support equipment to reduce losses and improve voltage performance; or

(b) contracting with Transpower for:

(i) an **NIC** under which Transpower agrees to provide, and the DTC agrees to pay for, voltage support or other equipment; and/or

(ii) a non-compliance arrangement pursuant to Appendix A of the Connection Code; or

(c) not contracting with Transpower but bearing the cost of their non-compliance. In many cases (where a lower *pf* has no particular consequences for the grid or other DTCs), there may be no cost. However, Transpower may have to invest in other cases to meet the grid reliability standards (**GRS**), or it may choose to do so for other reasons.

4.2.11 In setting the requirements in the Connection Code, the Commission considered that it would be reasonable for DTCs to weigh up the benefits of installing extra equipment, compared with entering into other arrangements with Transpower. A non-compliance agreement would avoid the need for the DTC to install costly plant and equipment, and if coupled with an NIC (where investment is required), would instead pass the costs of that particular DTC's non-compliance on to that DTC (in the spirit of causer pays). The Commission considers that, provided that non-compliance arrangements are made appropriately, the costs associated with static reactive supply will be allocated to DTCs appropriately and this will encourage efficiency in static reactive power investment decision making.

4.2.12 The question, however, is whether and how DTCs bear the cost where they are not complying with the power factor requirements and fail to either invest themselves or agree a NIC and/or non-compliance arrangement with Transpower (ie if they fall into category (c) in paragraph 4.2.10 above).

Connection assets

4.2.13 Where Transpower invests in connection assets, its costs are recoverable from the relevant DTC(s) on the basis of the TPM. This will be the case if the DTC has requested the investment or if its purpose is not for "grid voltage support", when considered during the regional peak demand period. The Commission considers that it is reasonable to determine the purpose of an investment as the purpose for which it is used during the regional peak demand period which means that the exclusion with respect to being an asset whose purpose is for grid voltage support is not relevant in this case.

4.2.14 Transpower has expressed concern that the Commission will not approve investment in connection assets under a GUP. It is true that the Commission would prefer connection asset investment to be the subject of an NIC, but there may be cases where approval under a GUP may be appropriate (and there are provisions in the Rules that expressly provide for GUP approval of connection assets as reliability investments).[18]

Interconnection assets

4.2.15 On the other hand, if the investment is *for "**grid voltage support** purposes and has not been installed at a **customer**'s request"*,[19] it will be an interconnection asset in terms of the TPM. This means that the costs will be allocated back to all load through the interconnection charge. Where an asset provides both grid voltage support and reactive power support to a DTC, while the investment may be the most efficient overall, the allocation of costs through the interconnection charge will be contrary to the causer pays principle.

Transmission agreement enforcement

4.2.16 In some cases, it may be more efficient for the DTC to invest itself and therefore an investment proposed by Transpower in a GUP will not pass the GIT. In that case, Transpower may choose to enforce the Benchmark Agreement or negotiated transmission agreement.

4.2.17 Transpower considers that enforcement may be problematic as the ultimate remedy set out in clause 15 of the Benchmark Agreement for "Technical Non-Compliance" (which includes non-compliance with the Connection Code) provides for Transpower to de-energise relevant Points of Connection or terminate. However, the Commission notes that clause 15 is expressly stated to be without prejudice to any other rights and remedies Transpower has under the Benchmark Agreement or at law. Transpower may choose to sue the DTC for a breach of the Benchmark Agreement (or negotiated transmission agreement). The general rule with a breach of contract is that damages are payable to put Transpower into the position it would have been if the DTCs *were* complying with the Benchmark Agreement (or negotiated transmission agreement). So, where Transpower suffers a loss as a result (e.g. because it has to invest and the cost of that is not approved), the DTC would have to pay Transpower for its share of that loss.

Result

4.2.18 The result of all this is that the cost imposed for the reactive demand at each point of service should (in **most** cases) be met by the DTC, either by investing in its own equipment, or paying Transpower through either an NIC or increased connection charges (or if all else fails, as damages for a breach of the transmission agreement.

[18] For example, see rule 5.6.3.2 of section II of part F of the Rules.

[19] See Rule 3.59.1 of Schedule 5 of section IV of part F of the Rules.

4.2.19 Amending the standard to unity or leading would have an added benefit of removing some of the issues around non-compliance, including its measurement.

Examples

4.2.20 Two examples of how the choices might work are included in the table below.

Example 1

DTC1 and DTC2 in the UNI each have a reactive offtake during the RCPD of 50 Mvar.

In order to maintain the GRS Transpower considers that **80 Mvar** of capacitors is required in the UNI, with the 20 Mvar balance of reactive offtake being supplied by grid-connected generating units.

Each DTC has 3 choices:

(a) *to invest in 50 Mvar (measured at the GXP) of reactive supply* in order to meet its power factor obligation under the Connection Code (as a term of its transmission agreement/Benchmark Agreement). (The actual requirement may well be more than this if the reactive demand is further down into the DTC's distribution system); or

(b) *to agree a non compliance agreement* with Transpower (in accordance with Appendix A to the Connection Code) *and either*:

(i) *invest in 40 Mvar* (half of what Transpower requires to maintain the GRS) of reactive supply *itself*; or

(ii) *agree to an NIC where Transpower invests in, and the DTC pays for, 50% of the costs of the required 80 Mvar* bank (ie the DTC demand/total demand in the region, both at the regional peak demand period); or

(c) *to pay 50% of the costs of the 80 Mvar bank pursuant to the TPM due to the asset being a connection asset* (and it being a term of the transmission agreement/Benchmark Agreement that the DTC pay according to the TPM[20]). In this case, if the DTC did not agree to do this as part of an NIC, it would technically be in breach of the Transmission Agreement/Benchmark Agreement by not meeting the Connection Code requirements in relation to power factor. However, provided the DTC pays its share of the costs of the connection asset, Transpower would not suffer any loss as a result and therefore no general damages would be payable for the breach.

[20] The Commission considers that this asset can be classified as a connection asset because it has not been installed for "grid voltage support" purposes but for the distributor's benefit.

Example 2

DTC1 and DTC2 in the UNI each have a reactive offtake during the RCPD of 50 Mvar.

In order to maintain the GRS Transpower considers that **110 Mvar** of capacitors is required in the UNI.

Each DTC has 3 choices:

(a) *to invest itself in the equivalent of 50 Mvar of reactive supply at the GXP* in order to meet its power factor obligation under the Connection Code (as a term of its transmission agreement/Benchmark Agreement);

(b) *to agree a non-compliance agreement with Transpower* (in accordance with Appendix A to the Connection Code) to allow for the reactive demand and then (under an NIC) *pay 50/110 (45%) of the costs of Transpower installing the required 110 Mvar* bank (ie the DTC demand/total demand in the region, both at the RCPD); or

(c) *if the asset is a connection asset in terms of the TPM to pay 45% of the costs of the 110 Mvar* bank. As with example 1(c), unless there was also a non-compliance agreement, there would be a technical breach of the transmission agreement/Benchmark Agreement. Transpower would need to submit an investment proposal to the Commission in a GUP for funding approval. If approval was granted it could then recover the remaining 10% of the costs of the investment as part of the interconnection charge under the TPM.

Issues with the amended status quo option.

4.2.21 The Commission's view is that the amended status quo option works provided that:

(a) the parties to the transmission agreement engage appropriately to agree non-compliance arrangements and NICs; and that any asymmetry of bargaining power can be overcome;

(b) DTCs can recover the costs of efficient investments on their side of the network;

(c) where the most efficient investments are interconnection assets, the appropriate portion is covered in an NIC; and

(d) Transpower can effectively enforce the transmission agreements if necessary.

4.2.22 The Commission is concerned that the amended status quo option may not provide the incentives intended (i.e. DTCs choosing the most efficient investment) because:

(a) DTCs can pass transmission charges through to their customers, whereas the Part 4 Commerce Act regime may not give DTCs certainty that the costs of their own efficient investments can be recovered. However as noted in paragraph 2.2.22**,** the Commerce Commission is proposing to address this regulatory anomaly;

(b) the definition of “connection asset” in the TPM may not always support the most efficient investment; and

(c) Transpower may not enforce technical non-compliance with transmission agreements.

4.2.23 As noted previously there appears to be a need to better facilitate the allocation of costs. This would result in a more prescriptive basis for cost recovery and reduce the potential transaction costs and uncertainty of negotiated non-compliance agreements with Transpower.

4.2.24 Additionally the present situation where the SO is contracting for dynamic reactive support on the transmission network is unlikely to be necessary to the same extent as new dynamic reactive compensation investments are made by Transpower and the costs are met under Part F. Over time this would reduce the present costs signal in the UNI.

4.2.25 The present non-compliance agreements are being negotiated on the basis they are temporary measures and a more permanent solution will be arrived at as part of the review.

4.3 Connection Asset Definition Option

4.3.1 This second option is an alternative to relying on the Connection Code as a means for allocating static reactive power investment costs to DTCs. It directly allocates the costs of any investment by Transpower in static reactive power devices to those who use them, as defined by their offtake during regional peak demand periods. As with the amended status quo option, DTCs face the choice of investing themselves, or paying for their portion of the investments made at a regional level.

4.3.2 However, one of the issues with the amended status quo option is that where the most efficient investment is in an interconnection asset, the causer(s) of the investment would not be paying their proportionate share of the costs unless they have agreed to do so under an NIC.

4.3.3 The Commission considers that one option to ensure that the incentives are correctly aligned would be to:

(a) widen the definition of “connection asset” in clause 3.59 of the TPM to include:

*any **static reactive support asset**, or any part or group of **static reactive support assets,** to the extent that it delivers to the **customer**;*

(b) include a statement that:

*The extent to which a **static reactive support asset** or group of **static reactive support assets** delivers **reactive power** to a **customer** is determined by:*

*A. calculating the average kvar taken by the **customer** in the **regional peak demand period** in the relevant region; and*

*B. dividing A by the total capacity of all **static reactive support assets** in the relevant region.*

(c) include the following definition as a new clause 3.51 of the TPM:

*"**static reactive support asset**" means a switched or fixed capacitor connected as shunt compensation commissioned after [date] that delivers **reactive power** to a **customer** or **customers**."*

4.3.4 The Commission considers that, if the definition of "connection asset" is changed to better reflect the user pays principle for reactive power investments, then a (unity) power factor obligation on DTCs is less important. In that light, a minimum 0.98 power factor lagging obligation in the UNI and USI regions would probably be sufficient as a backstop. This would have an added benefit of removing some of the issues around non-compliance, including its measurement.

Issues with the Connection Asset Definition Option

4.3.5 The Commission's main concern with the Connection Asset Definition Option is it may result in reduced incentives for DTCs to make their own investments on their side of the network, even where these are more efficient, since transmission charges can be passed through to their customers. However as noted in paragraph 2.2.22 the Commerce Commission is proposing to address this regulatory anomaly.

4.4 Option 3 – kvar charging method

4.4.1 Notwithstanding the issues of the ability of distribution companies to pass costs through to the consumers connected to their network, an alternative solution to this issue is to:

(a) determine an appropriate kvar charge to incentivise more cost effective investment in static reactive support, either in the transmission network or in the distribution network in each case, regardless of the power factor at the GXP in question; and

(b) allocate the charges to causers of the investment in the most appropriate way.

4.4.2 The UNI region is taken as an example requiring new investment. If a distribution company does not wish to invest in reactive support to meet its own needs for reactive power[21], then this investment requirement would fall to Transpower. Following the investment the distribution company in question could then nominate what it considers to be their peak kvar requirement for the year[22], which would be consolidated with those of the other distribution companies.

4.4.3 This consolidated peak kvar level could then be costed at the replacement cost of the static reactive investment Transpower would need to make to compensate for the reactive power drawn from the grid. Each distribution company would then pay its proportion of the investment cost based on its own predicted peak kvar level.

4.4.4 If this peak kvar level was exceeded then a penalty charge would need to be made to discourage this. Any excess of the predicted amount would need to be supplied by the dynamic reactive sources in the region. It would make sense to cost this excess at the $/kvar cost of dynamic reactive support.

4.4.5 The use of the regional dynamic reactive sources for maintaining steady state voltages would need to be actively discouraged through the penalty charge. These devices are in place to counter any dynamic voltage stability issues in recovery from fault conditions on the transmission network. Additionally this is an economically inefficient means to maintain steady state voltages given the costs involved.

4.4.6 This allocation method would be the same as the process in place in part C, where the SO contracts for dynamic voltage support services and allocates these costs proportionally to the local distribution lines companies. This would be the least controversial and easiest method to implement given that the distributors are familiar with the process and methodology, particularly in the UNI.

4.4.7 The suggested allocation method would also be likely to result in a reduction and fairer allocation of such costs faced directly by distributors as future part F

[21] By definition any reactive power flow across a GXP results in a power factor which is not unity. Uncompensated reactive power demand by the distribution network has to be met on the transmission grid as otherwise transmission voltages cannot be maintained. Accordingly, connected parties that draw off reactive power from the grid cause the need for the transmission investment.

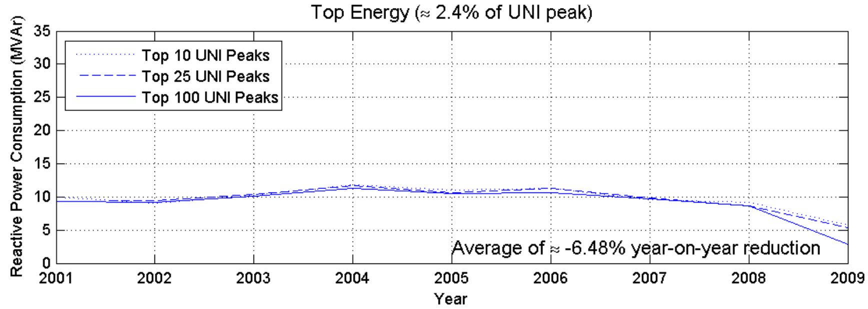
[22] The peak period definition should be the same one for determining other transmission charges i.e. the 12 peak RCPD method as this is when high levels of reactive support are required in the transmission network.

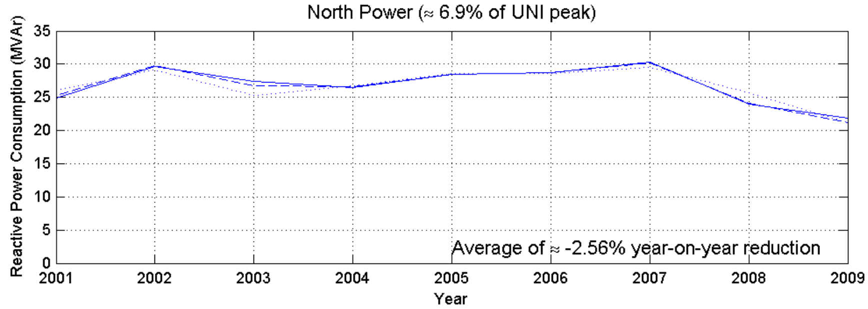
investments (UNI reactive support proposal) could largely eliminate the need for the SO to contract separately for dynamic reactive reserves.

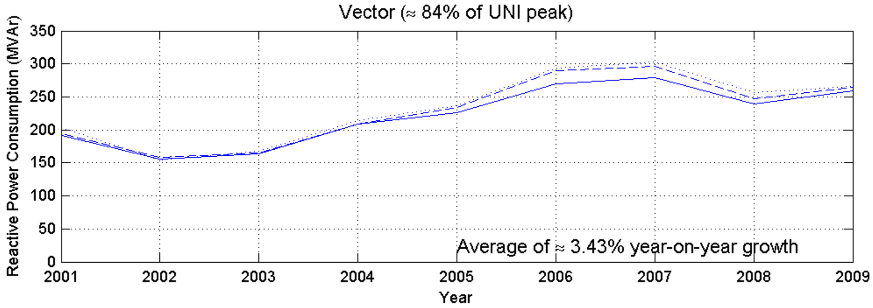
4.4.8 If required, the development of detailed methodology for charging for reactive power would be Transpower's responsibility as part of developing the TPM in response to specific guidelines provided by the Commission under rule 7 (Part F Section IV). If this option is pursued the Commission will need to consider development of the key components of any such guideline.

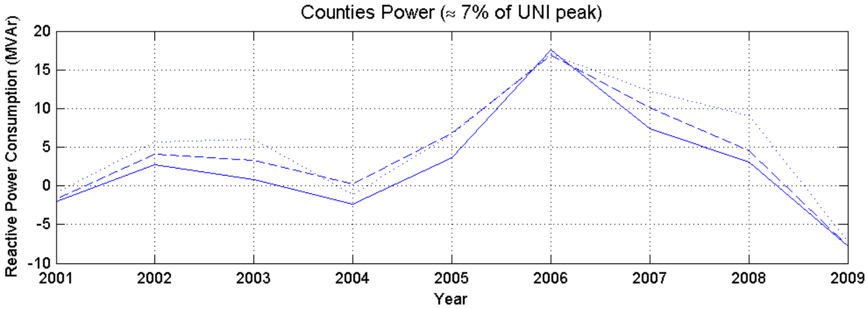
Attachment 1 Regional reactive power consumption at peak - UNI & USI

1.1 Regional reactive power consumption for distributors in the UNI









1.2 Regional reactive power consumption for distributors in the USI