Transmission Pricing Advisory Group

Draft Section 7: Static Reactive Compensation

Version 1: for TPAG review

6 May 2011

Note: This paper has been prepared for review by TPAG. Content should not be interpreted as representing the views or policy of the Electricity Authority or of TPAG.

Contents

7 Assessing options for static reactive compensation

7.1 Introduction

7.1.1 [Sub-committee setup and process text – may not belong here.]

7.1.2 TPAG agreed at its meeting of 14 March 2011 to establish a sub-committee to progress work on the treatment of static reactive compensation (SRC) costs. The sub-committee members are:

- John Clark
- Bruce Girdwood
- Guy Waipara
- David Hume (Authority representative)

7.1.3 The SRC sub-committee is supported by Clive Bull of Strata Energy Consulting.

7.1.4 The Scope of Work for the SRC sub-committee required it to provide a recommendation to TPAG for a preferred TPM option, and associated guidelines, for the treatment of SRC costs.

7.1.5 TPAG's assessment of options for SRC investment follows the analysis framework set out in section 4 which is based on the statutory objective as it is applied by the CAPs.

7.1.6 This section:

- considers issues arising from the current arrangements for SRC, and possible regulatory improvements and efficiency gains that could be achieved in addressing them;
- considers alternative options; and
- assesses the relative costs and benefits of the options.

7.2 Issues with the current arrangements for static reactive compensation

Background

7.2.1 SRC refers to sources of reactive power[1] that provide local voltage support and increase power transfer limits into regions that are subject to voltage instability. Both the Upper North Island (UNI) and Upper South Island (USI) are regions where the transmission capacity of Transpower's grid is capped by voltage stability limits.

7.2.2 Improving the power factor[2] of loads (by lowering their reactive power consumption), and/or providing additional SRC within networks at or near the load centres are both ways of increasing voltage stability limits[3] and decreasing network losses[4].

[1] Such as static capacitor banks connected to networks or within customer electrical installations. Reactive power is the component of power that that continuously flows between reactive sources and sinks within the network but conveys no net flow of energy. It is thus an 'overhead' of real power transmission in an AC network.

[2] Power factor is a measure of the efficiency of the transmission of power in a network. The power factor is the ratio between the real power and apparent power flowing at a point in a network. The highest high power factor is equal to 1.0 (or unity) and represents the state where there is only real (useful) power and no reactive power flowing past the measurement point. A power factor of 0.95 means that one unit of reactive power is flowing (and reducing the capacity for the transmission of real power) for every three units of real power (e.g. 33 MVAr of reactive power and 100 MW of real power).

7.2.3 Transpower has forecast the need for substantial levels of reactive power investment in the UNI and USI regions for the next 10 – 15 years[5]. A proportion of the investment in these regions is required to support the reactive power demands of transmission customers. Although the investment is relatively small in the overall scale of current transmission investments, the benefits, in terms of increased transmission capacity and the consequent deferral of major transmission line upgrades, are large.

7.2.4 In some circumstances, SRC investment may be more efficient if the equipment was located within local distribution networks or in end-use customers' electrical installations, rather than within the transmission network[6].

7.2.5 Status quo arrangements rely on the power factor standard in the Connection Code[7] to determine the allocation of costs for SRC investment. This mechanism relies on the parties to the bilateral transmission contract framework to make alternative arrangements where the requirements in the Connection Code are not appropriate for particular points of service. However, these arrangements have been controversial with designated transmission customers (DTCs) and Transpower.

7.2.6 DTCs have argued that the 'unity power factor' requirement in the Connection Code, intended by the Commission as an investment cost allocator, puts them in automatic breach of the Connection Code, as it is not possible to achieve in practice[8].

7.2.7 Transpower has argued that it has no effective mechanism within the Connection Code for dealing with the issues associated with power factor measurement accuracy and the inevitable breaches of the requirement that will arise. A standoff situation has developed, whereby Transpower has, in some cases, entered into non-compliance agreements with DTCs and in others chosen, at least for the time being, not to pursue the matter.

Problem definition

7.2.8 The objective is to incentivise efficient investment in SRC equipment by ensuring that DTCs pay a cost-reflective charge for the reactive component of power flowing into a distribution network or a directly connected customer's premises. Potentially, the status quo, relying solely on the power factor requirements of the Connection Code, may not provide sufficient prescription to workably support the allocation of costs to causers through the mechanism of non-compliance agreements.

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[3] Traditionally, power factor is used in thermally constrained systems to indicate the amount of real (or useful) power being consumed or supplied. A power factor improvement from 0.94 to 0.99 increases real power transfer by 5%. This is not true for voltage stability constrained regions where improvement in power factor can significantly increase power transfer (voltage stability) limits. For example, in the USI an increase from 0.99 (lagging) to unity can increase power transfer limits by up to 5%.

[4] As the network itself (i.e. the lines and transformers through which the power flows) consumes reactive power when operating at high load levels, the greater the distance over which reactive power must flow to compensate a region with net poor power factor loads, the greater are the losses involved in its transmission.

[5] Transpower, Annual Planning Report 2011.

[6] Previous analysis by the Commission indicated that if demand power factor correction is required to support transmission then it is more efficient, in terms of net benefits, to correct power factor on the distribution network rather than the transmission grid. This is because the lower cost of grid-connected capacitors is outweighed by the reduced losses in the distribution network when SRC equipment is located close to poor power factor loads.

[7] The Connection Code is incorporated into the Code by reference at Clause 12.26. The relevant section (4.4 Minimum power factor) requires from 1 April 2010 for power drawn off the grid, that the customer must maintain a power factor of not less than 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.

[8] Maintaining exactly unity power factor at any point of service, as the Connection Code requires, is not within a DTC's practical ability to fine tune in operational timeframes.

7.2.9 Thus, the status quo arrangements in respect of reactive power arrangements could be considered to be a regulatory failure in respect of their reliance on the current minimum power factor requirements in the Connection Code; this, in turn, could lead to potential dynamic inefficiencies in the way that investments in SRC equipment are made.

7.2.10 The next section identifies options that might address these issues, building on earlier work undertaken by the Commission and including the consultation stages completed and the subsequent responses provided by submitters[9]. The approach adopted in this section seeks to ensure consistency with the assessment framework and its application as developed and used by TPAG for the core TPM review.

7.3 The Options

7.3.1 The stage 2 consultation paper suggested that there may be benefits in alternative reactive power investment regimes. It proposed three possible alternatives to the status quo. These options are summarised in Table 1.

Table 1 Reactive power stage 2 options

Option	Description	Rationale for Change
Status quo	No change to current arrangements, whereby the Connection Code requires that grid off-take at points of service have unity power factor during periods of regional coincident peak demand.	
1: Amended status quo	Widen the acceptable power factor range by requiring that off-take customers maintain 'unity or leading power factor[10]' during regional peak demand periods. Otherwise, as for the status quo option, retain the Connection Code mechanism for implementing the beneficiary-pays principle.	A power factor range is practically achievable for transmission customers. Hence, it should remove the concerns in respect of the status quo requirement to maintain unity power factor. Investment efficiency is still intended to be provided by allocating responsibility for point of service power factor correction to the transmission customer, who could choose between alternatives.

[9] See http://www.ea.govt.nz/our-work/consultations/transmission/tpr-stage2options/

[10] For demand, a leading power factor is where reactive power flows in the opposite direction to the real power flow. So if the power flow is into the distribution network, the reactive power flow would be back into the transmission grid. Flows of reactive power against the predominant direction of real power flow can, within certain bounds, be beneficial in terms of transmission stability.

Option	Description	Rationale for Change
2: Connection asset definition	Include new regional SRC equipment within the definition of connection assets. Widen the status quo power factor range within the Connection Code to provide a fall back minimum power factor of 0.98 lagging.	Investment efficiency is still achieved by allocating responsibility for point of service power factor correction to the DTC, who could choose between alternatives. If a net reactive power demand persists during periods of regional peak demand, any grid-connected SRC equipment necessary to supply this demand is charged user-specifically to the DTC causing the demand, via the connection charge. The Connection Code power factor requirement is widened to provide a fall back de minimis.
3: kvar charge	A new reactive power charge is implemented that charges DTCs for the reactive power taken off the grid by them during regional peak demand periods. The charge is set at a level that reflects the investment costs of providing new regional SRC equipment. Widen the status quo power factor range within the Connection Code to provide a fall back minimum power factor of 0.98 lagging.	Investment efficiency is still provided by allocating responsibility for point of service power factor correction to the DTC, who could choose between alternatives. If a net reactive power demand persists during periods of regional peak demand, a charge is levied for this. The Connection Code power factor requirement is widened to provide a fall back de minimis.

7.3.2 The following sections elaborate on the options identified in the table above[11].

Status quo option

7.3.3 The status quo provisions for reactive power were developed by the Commission on the basis of the following rationale.

a) The power factor requirements in the Connection Code are intended to form the basis of cost allocation – users taking reactive power off the grid at a point of service at times of peak regional demand are allocated responsibility for the costs of its provision.

b) The Connection Code forms part of the transmission agreement between Transpower and a DTC and enforcement of the provisions of the Connection Code are therefore a bilateral matter between Transpower and the relevant DTC.

c) While the Connection Code is intended to set out the technical standards and requirements that Transpower and DTCs must meet, it can be departed from where non-compliance agreements are negotiated. If a cost was involved in a specific case of departure (such as where agreement was reached that Transpower would make an investment in SRC equipment), the responsibility for that

[11] Further detail of how these options might work is provided in Appendix 5 of the stage 1 consultation paper.

cost, while not prescribed in the Connection Code, can be negotiated and allocated to the party causing the departure from the Connection Code.

7.3.4 Thus, DTCs would have choices in meeting their Connection Code obligations in respect of reactive power. The alternatives are not mutually exclusive (i.e. a combination may provide an optimal outcome) and would include:

a) investing in SRC equipment themselves and locating it optimally within their distribution networks[12];

b) requiring or incentivising their end-use customers to invest in power factor correction equipment or in appliance choices that provide good power factor performance; and

c) entering into a new investment agreement with Transpower, which would provide and operate large-scale SRC equipment (e.g. static capacitor banks) connected to the grid within the local region.

Amended status quo option

7.3.5 As noted earlier, DTCs have argued that the 'unity power factor' requirement in the Connection Code, puts them in automatic breach of the Connection Code, as it is not practically possible to achieve. Transpower has argued that it has no effective mechanism for ensuring compliance within the Connection Code when dealing with the inevitable breaches, and the potential for hold out, by DTCs.

7.3.6 An amended status quo option would involve amending the minimum power factor standard in the Connection Code for the USI and UNI regions to 'unity <u>or leading</u> power factor' (rather than 'not less than unity power factor') and retaining this standard as a basis for determining the allocation of costs for any grid-based SRC investment.

7.3.7 Amending the Connection Code standard to unity <u>or leading</u> power factor has the benefit of removing some of the issues around non-compliance that were introduced by the status quo arrangements but retains its intended compliance mechanism.

Connection asset definition option

7.3.8 This would involve a transmission pricing-based solution that requires:

a) widening the definition of 'connection asset' to include new SRC investments to the extent to which they deliver reactive power to DTCs in a region; and

b) retaining but relaxing the power factor requirement in the Connection Code to 0.98 lagging, so as to provide a fall-back power factor provision.

7.3.9 The 'extent to which they deliver reactive power to customers in a region' is determined by:

a) calculating the average kvar taken by a DTC in the regional peak demand period in the relevant region (either the UNI or USI region); and

b) dividing the amount determined in a) by the total capacity of all SRC assets in the relevant region.

[12] Optimal location would provide addition benefits by possibly deferring the onset of constraints and/or minimising losses within their own distribution networks.

7.3.10 Thus, an annual charge would be calculated and invoiced once the point of service metering data from the annual regional peak demand period was available. It would apply once a new regional transmission SRC asset was built.

7.3.11 This arrangement seeks to include grid-connected SRC equipment, such as static capacitor banks, within the class of connection assets and to user-specifically recover their costs through a targeted new charge. This would implement the beneficiary-pays principle and provide DTCs with an option to either:

a) provide power factor correction measures within their own networks (and/or encourage/require their end-use customers to do so within the customers' electrical installations); or

b) rely on Transpower to provide power factor correction through investment in grid-connected SRC equipment, for which they would incur a cost-reflective charge.

kvar charge option

7.3.12 This option is similar to the connection asset definition option in that it relies on a transmission pricing-based mechanism to establish an efficient investment price signal. It would involve determining an appropriate kvar charge for grid-supplied reactive power to incentivise more efficient investment in SRC equipment. It would be applied to new investments only.

7.3.13 The proposed charge under this option would require that, once a new investment in SRC equipment was made by Transpower, DTCs would forecast and nominate to Transpower their aggregate average kvar draw from the transmission grid during the forthcoming regional coincident peak demand (RCPD) period.

7.3.14 Transpower would calculate a kvar rate based on the replacement cost of a suitable investment in SRC equipment, determined by consolidating all DTC nominations within the relevant region. A penalty charge would be applied for usage over a DTC's nominated quantity, set at a rate based on the (higher) cost of providing dynamic reactive compensation equipment.

7.3.15 DTCs would respond to the kvar price signal by paying for grid-supplied reactive power (as measured at the RCPD periods) and, at their option, seek to reduce the charge by investing where efficient in their own SRC equipment and/or encouraging their end-use customers to maintain high power factors.

TPAG review of options

Option 1 – amended status quo

7.3.16 TPAG has reviewed the options following consideration of the consultation papers and submitted views and considers that option 1, amended status quo, is appropriate for assessment against the Authority's statutory objective and the Code amendment principles.

Option 2 – connection asset definition

7.3.17 In the case of option 2, connection asset definition, TPAG considers there are issues with the option as defined, as follows:

a) Defining regional SRC assets as 'connection assets' creates potential confusion by effectively creating two sub-classes of connection assets that differ in the ways they are charged for:

i) ‘normal’ connection assets, the costs of which are recovered through asset-specific $/year charges invoiced monthly to DTCs; and

ii) ‘static reactive support’ connection assets, the costs of which are recovered through a new charge that is based on each in-region DTC’s aggregate kvar draw at its points of service, following establishment of the annual RCPD period.

Thus, there would be two different cost allocation methodologies for connection assets.

b) The proposal to limit the new charge to apply to only new SRC assets would mean that the pricing signal would not be created until a suitable new investment was completed.

c) Linking a charge asset-specifically to identified SRC equipment (such as specific grid-connected static capacitor banks) would imply that new investments should be subject to new investment agreements, in the same way that other new investments in connection assets are made. This would likely involve a multi-party negotiation.

7.3.18 TPAG also observes that this option is in effect a kvar charge, because dollar costs are being recovered per kvar demand measured in a defined assessment period.

7.3.19 For these reasons, TPAG considers that while the general intent to create a pricing signal appears to be sound, the issues that arise from linking charges to specific assets in a form of modified connection charge make option 2, as defined, unworkable.

Option 3 – kvar charge

7.3.20 In the case of option 3, while the concept underlying a kvar change appears sound, TPAG has concerns with:

a) the workability of ‘nominate and penalty’ methodologies; and

b) the proposal, in common with option 2, that the charge apply only after Transpower made a new investment in SRC assets.

7.3.21 Submitters voiced concerns over the difficulty of forecasting a suitable level of average kvar for the coming RCPD assessment period and on the basis for establishing a suitable penalty rate, the purpose of which would be to encourage accurate nomination. TPAG considers these concerns are valid and that a better option is likely available that would provide the benefits of efficient price signalling without the drawbacks of the options identified to this point.

Option 4 – amended kvar charge

7.3.22 In essence, a price signal is required so that DTCs can make efficient choices to invest in SRC equipment and/or encourage or require their end-use customers to likewise take steps to improve any poor power factor. If Transpower were to invest in such equipment, an efficient kvar charge could be readily constructed by dividing the capital and operating costs it incurred by the capacity provided.

7.3.23 The principle that DTCs should face the costs incurred for their average aggregate kvar draw from the grid at times of RCPD provides an appropriate cost allocator.

7.3.24 Existing SRC assets that provide regional reactive power needs are incorporated in the interconnection charge. Accordingly, the revenue raised by Transpower through a new kvar charge should displace revenue that would otherwise be recovered through the interconnection charge.

7.3.25 An ‘interconnection-like’ methodology could apply to the kvar charge. Thus, an amended kvar charge mechanism could work as follows:

a) Transpower determines the long-run marginal cost of grid-connected SRC equipment. This provides an efficient kvar charge rate and can be arrived at by dividing the estimated annual capital and operating cost of a suitable new asset (or group of assets) by the capacity it (they) would provide.

b) Transpower gathers the kvar demand data from the RCPD periods from the immediately preceding September – August capacity measurement period. From this data, it assesses the average reactive power draw from the grid in kvar, for each DTC in the UNI region and separately for the USI region. If a DTC’s net reactive power flow during the assessment period is ‘negative’ (i.e. reactive power is injected into the grid), the assessed quantity is set at zero.

c) Transpower calculates the expected revenue to be recovered from the kvar charge for the coming year by multiplying the result in a) by that in b).

d) The interconnection charge is calculated as it is now, except that the expected kvar charge revenue determined in c) is subtracted from the interconnection revenue before the interconnection rate is calculated. This ensures that Transpower’s target revenue is the same as it would have been without the kvar charge.

7.3.26 Thus, the current year’s kvar charge is set based on the immediately preceding year’s kvar demand, using the same methodology as is used for the interconnection charge. The benefit for a DTC from decreasing their reactive power draw from the grid during the RCPD period is gained in the following year, since the impact of reduced reactive power draw is reflected in the following year’s kvar charge.

7.3.27 Distributors subject to the Commerce Commission’s price path regulation should be able to benefit where they invest efficiently in transmission alternatives.

7.3.28 If a kvar charge were calculated based on the methodology outlined, it would have the following indicative effect:

Table 2 Amended kvar charge Illustrated

[Draft data only! – numbers to be confirmed]

	USI region	UNI region	Comment
LRMC of grid SRC equipment = kvar charge rate	$5/kvar	$5/kvar	c.f. interconnection charge @ $70/kW
RCPD total reactive power demand	100,000 kvar	280,000 kvar	Based on 2010 RCPD data
kvar charge revenue	$0.5M	$1.4M	
Reduction in interconnection rate	$x/kW	$x/kW	Based on 2010

Options selected for assessment

7.3.29 From the discussion in this section, the options that will be assessed against the status quo in the following section are:

a) Option 1 – amended status quo; and

b) Option 4 – amended kvar charge

7.4 Assessment of options against efficiency considerations

7.4.1 This section assesses the options relative to the status quo under each of the efficiency considerations set out in [section 4] and the introductory comments relating to TPAG's approach to assessment based on the Authority's statutory objective and the Code amendment principles (see sections 4.1 and 4.2.1 – 4.2.8).

Efficiency consideration 1: beneficiary pays

7.4.2 As has been noted, TPAG supports the application of the beneficiaries approach as discussed in [section 4] and considers that there are benefits to the investment decision-making process where beneficiaries can be readily identified, noting that, as explained in [section 4], it is not necessary to identify all beneficiaries.

7.4.3 In general, the beneficiaries of grid-connected SRC equipment can be readily identified at points of service because the static reactive support service being provided is:

a) able to be clearly defined – it is the provision of an aggregate average quantity[13] of reactive power that flows into the point of service during the RCPD period and can be expressed as an average demand over the assessment period in kvar;

b) measurable – revenue-grade metering equipment is located at every point of service that records both real and reactive power flows in each direction in each half hour trading period (so-called four-quadrant metering);

c) provided on a bilateral basis – the parties at each point of service are, in all cases, one DTC and Transpower; and

d) able to be valued – it can be directly related to the long-run marginal cost of providing grid SRC assets.

7.4.4 However, while a case can be developed under the beneficiary pays principle, the question of investment materiality must be considered. It is important to explicitly identify the asset investments that might be beneficially impacted by any beneficiary-pays mechanism. The two investment categories are:

a) major grid upgrades of transmission capacity into voltage constrained regions (such as the UNI and USI regions), typically involving the addition of new inter-regional transmission lines; and

b) investments in regional SRC equipment, such as:

i) grid and distribution network connected static capacitor banks; and

ii) demand-side management options, such as in-premises power factor correction equipment or selection of high power-factor appliances.

7.4.5 The mechanism being considered here should not impact on the timing of major capacity investments in grid capacity, such as new transmission lines into regions that are becoming constrained. The key

[13] Reflecting that reactive power can flow in either direction at any instance in time and that the assessment of service provision in this case will be in half hour periods.

assumption underpinning this view is that Transpower will always develop and submit for approval main transmission investments in an optimal sequence and consider non-transmission alternatives, including demand side management.

7.4.6 Thus, if a DTC maintained an aggregate poor factor across its points of service within a region in regional peak demand periods, Transpower would seek to invest first in all available lower cost options before seeking to have a major transmission line investment approved. Lower cost options would normally include one or more stages of grid-connected SRC equipment within the constrained region (up to the point where all of these options were exhausted[14]).

7.4.7 In summary therefore, the mechanism being considered impacts the dynamic efficiency of investments in regional SRC equipment.

Conclusion on beneficiary pays

7.4.8 TPAG concludes that a beneficiary pays approach has merit in the case of SRC equipment investment since:

- the service being provided by Transpower can be clearly identified and is measurable; and
- the beneficiaries can generally be clearly identified.

7.4.9 However, the relevant future investments, being those that provide regional SRC equipment, are likely to be modest when compared with investments in major transmission equipment.

7.4.10 Option 1 would implement a beneficiary pays principle if DTCs were to enter into new investment agreements with Transpower. It has no advantage in this respect over the status quo option, which would rely on the same mechanism.

7.4.11 Option 4 would implement a beneficiary pay principle based on DTC point of service reactive power demands in the previous year and does not rely on them concluding new investment agreements with Transpower. It is therefore assessed as being superior to the status quo option in this respect.

Efficiency consideration 2: location price signalling

7.4.12 As noted in [section 4.2.12], location price signalling in the context of transmission pricing can incentivise efficient co-ordination of demand-side and transmission investment and efficient trade-offs between the costs and benefits of reliability.

7.4.13 The spot market in New Zealand has been developed on a framework that considers only the flow of inter-nodal real power. Reactive power flows are not taken into account and thus no pricing signals are provided for it within the energy market.

7.4.14 In terms of the current TPM, existing regional SRC installations are classified as interconnection assets – accordingly the costs are recovered on a non-locational basis.

7.4.15 The location of investments in regional SRC equipment (including demand-side alternatives) has a material bearing on both the costs and range of benefits provided. For example, the following hypothetical alternative investments could all provide valid solutions to poor power factor within a region:

[14] In practice, a maximum level of regional SRC compensation exists, such that no further voltage stability is gained through the further addition of SRC equipment. At this point, other options that provide improvements to the dynamic stability of the network must be considered.

a) Transpower builds a 50 Mvar static capacitor bank at a major regional transmission node.

b) The local distributor installs 5 Mvar static capacitor banks at six of its zone substations and replaces several overhead 33 kV sub-transmission circuits with underground cables.

c) Large industrial customers install power factor correction capacitors in their premises and all customers select high power factor appliances (e.g. high p.f. compact fluorescent lighting).

7.4.16 The selection of specific power factor correction solutions, such as those in the examples above, is not mutually exclusive. Some level of investment at each of the transmission, distribution and end-consumer levels is likely to provide an optimal level of efficiency by maximising transmission and distribution capacity while minimising electrical losses. Seeking to provide a location price signal for investment in SRC equipment is therefore likely to be beneficial.

Quantification of benefits

7.4.17 The benefits are associated with <u>loss benefits</u> and also <u>thermal capacity increases</u> within the connected networks.

Loss benefits

7.4.18 Estimates of loss benefits have previously been made[15]. SKM estimates that improvements in power factor, in this case to unity, could provide roughly $10m in savings. Thus, there is *potential for up to* $10m in savings in losses in the upper island regions.

Thermal Capacity benefits

7.4.19 Given that existing point of service power factors are generally quite high in the upper island regions, the potential for achieving further thermal capacity increases would appear to be limited. However, improving from 0.99 lagging to unity gives a 1% capacity increase. Using the 'rule-of-thumb' of $1m/MW for transmission augmentation could give:

a) For the UNI (approx. 2000 MW @ 0.99 p.f.) a potential of up to 20MW (1%) increase in capacity.

b) For the USI (approx. 1060 MW @ 0.995 p.f.) a potential of up to a 5MW (0.5%) increase in capacity.

7.4.20 Hence, there appears to be a potential benefit from introducing a location price signal of up to $25m.

Overall benefits

7.4.21 Given the above, overall benefits might fall within the range from $3.5m (if 10% of the potential were realised) up to $35m.

Conclusion on location price signalling

7.4.22 TPAG concludes that introducing an efficient location price signal for investment in regional SRC equipment is viable and likely to provide benefits against the status quo option.

7.4.23 Option 1 would provide a location price signal for alternative asset investments, *but only if* DTCs were to enter into new investment agreements with Transpower. It has no advantage in this respect over the status quo option, which relies on the same mechanism.

[15] SKM [need reference]

7.4.24 Option 4 would provide an efficient location price signal for alternative asset investments by introducing a kvar charge on average reactive power drawn from the grid during RCPD periods. The kvar charge would be set at the long run marginal cost of a grid SRC asset investment. In addition, option 4 does not rely on DTCs concluding new investment agreements with Transpower. It is therefore assessed as being superior to the status quo option.

Efficiency consideration 3: unintended efficiency impacts

7.4.25 As has been noted already, option 1 is unlikely to deliver any materially different investment behaviour from DTCs compared with the status quo.

7.4.26 Option 4 is likely to incentivise investment in SRC equipment by DTCs. DTCs would face an efficient investment signal through the kvar charge. Distributors could also pass a similar signal on to their end-use customers.

7.4.27 With the introduction of a kvar charge, some costs would be shifted from those that pay the interconnection charge to those that would be subject to the new kvar charge. However, this would provide an efficiency gain.

7.4.28 Once a kvar charge were in place, significant investments in SRC equipment downstream of the point of service would have the effect of:

a) reducing the utilisation of existing grid SRC assets; and

b) deferring investment in future grid SRC assets.

7.4.29 The first effect could introduce unintended efficiency impacts under a kvar charge because any decreased year on year kvar charge revenue would be recovered from the interconnection charge and thereby shift costs between participants. At the limit, where all DTCs maintained average leading power factor at their points of service, there would be no kvar charge revenue.

7.4.30 However, the kvar charge revenue levels indicated in Table 2 show that this effect would be extremely small compared against the magnitude of the interconnection charge revenue. In addition, in practical terms, existing grid SRC assets are unlikely to become stranded as a result of incentivised DTC and end-use customer investments in power factor improvements. The likely outcome is that they would simply defer future grid investments.

Conclusion on unintended efficiency impacts

7.4.31 TPAG concludes that :

- Option 1 would be no different to the status quo option in respect of unintended efficiency impacts.
- Option 4 is unlikely on balance to provide significant unintended efficiency impacts compared with the status quo.

Efficiency consideration 4: competitive neutrality

7.4.32 The parties interested in investments in SRC equipment are network owners and their customers (being energy retailers and end-use customers). Introducing an efficient price signal that would encourage efficient investment in SRC equipment would appear to raise no competitive neutrality issues.

7.4.33 However, both the status quo and amended status quo options appears to bias future investment in needed reactive power support equipment towards grid investments, as these options rely on the Connection Code to trigger efficient investment in transmission alternatives and this mechanism appears to be unworkable based on current participant behaviours. [Note: the description of competitive neutrality in section 4.3.12 refers to competition for new investment in new generation and DSM. I'm not sure that the interpretation I've made here works. If it is just about competition in energy, then there are no competitive neutrality issues with any of the options here.]

Conclusions on competitive neutrality

7.4.34 TPAG concludes that the competitive neutrality issues inherent in the status quo and amended status quo options should be mitigated under option 4.

Efficiency consideration 5: implementation and operating costs

7.4.35 Option 1 is essentially the same as the status quo, and would require a small regulatory cost in providing the necessary Connection Code amendment.

7.4.36 As outlined in paragraph 7.3.25, option 4 relies on a substantially similar pricing mechanism to the existing interconnection charge. Advice from Transpower indicates an implementation cost in the range $400 – 600k. Ongoing costs should be a very small increment of the existing cost to provide transmission billing.

7.4.37 DTCs would face minor incremental costs in processing kvar charge invoices and there would be a small regulatory cost involved in introducing the change into the TPM.

Conclusions on implementation and on-going costs

7.4.38 TPAG concludes that the implementation and on-going costs would be as follows:

- Option 1 would be trivial.
- Implementation of option 4 would be in the range $400 – 600k, based on advice received from Transpower. On-going operating costs would be relatively trivial.

Efficiency consideration 6: good regulatory practice

7.4.39 Triggering the review of reactive power arrangements was a key concern that the status quo option does not implement good regulatory practice. Relying on the mechanism of the Connection Code to initiate efficient investments in reactive support equipment was identified by several submitters to previous rounds of consultation as raising significant concerns.

7.4.40 The amended status quo option does not materially improve on the status quo. While the specific concern relating to the impracticability of arranging for exactly unity power factor at a point (or points) of service is somewhat mitigated by providing a range of power factors that would provide compliance, the broader concerns in respect of Transpower's inability to enforce compliance and the difficulties inherent in concluding multi-party new investment agreements, remain.

7.4.41 Accordingly, the amended status quo option is not considered to be a viable option in terms of resolving the regulatory practice issue identified in the problem definition.

7.4.42 The option of introducing a kvar charge is assessed in Table 3 against the good regulatory practice criteria that were introduced in paragraph [4.3.15].

Table 3 Assessment against good regulatory practice principles

Principle	Comment
Consistency between regulators	A kvar charge is compatible with the Commerce Commission's transmission alternatives provision within the price path regulation that applies to non-exempt distributors. This provides for distributors to retain some of the benefits where they efficiently invest in transmission alternatives.
Durability	From submissions received on the stage 2 consultation, a kvar charge methodology for reactive power was broadly supported by those parties that would be most directly involved. While the stage 2 options (options 2 and 3 introduced earlier in this section) have been modified further by TPAG to develop an option 4, they are considered to be conceptually very similar to option 4. TPAG would expect the previous level of support to endure with option 4.
Consistency over time	A long run marginal cost-based kvar charge should provide an enhanced and stable environment for investment decision making in the provision of SRC equipment over time.
Consistency over whole grid	The kvar charge mechanism is proposed to apply only in the regions of the grid that are subject to voltage constraint, being the USI and UNI. The mechanism is thus consistent within those regions but is unnecessary for the foreseeable future within the unconstrained LSI and LNI regions.
Wealth transfers and step changes in prices	An initial wealth transfer and price step could be expected in the transmission charges for DTCs in the UNI and USI that have significant net reactive power draws from the grid in the RCPD period. Once certainty is provided that the charge is to be introduced, these parties will have an opportunity to evaluate and possibly undertake investments that would mitigate the price step change. In any case, Table 2 indicates that the kvar charge is relatively modest in the revenue it would collect when compared against the other transmission charge components and efficiency gains have been identified for the option.
Workability	The proposed kvar charge methodology is conceptually similar to and compatible with the existing interconnection charge. It is a simple mechanism that DTCs can directly use in their investment decision making in respect of reactive power management within their networks.

Conclusions on good regulatory practice

7.4.43 TPAG concludes that:

- Option 1 does not implement materially improved regulatory practice against the status quo option.
- Option 2 implements good regulatory practice under all of the assessment criteria in this section.

Assessment summary

7.4.44 This summary provides:

a) A comparison of pros and cons of the options; and

b) A summary of the assessment of the options relative to the status quo.

7.4.45 Table 4 summarises the TPAG assessment of the advantages and disadvantages of the SRC options considered in this discussion paper.

Table 4 Advantages and disadvantages of SRC options

Option	Pros	Cons
Status Quo	• None	• Not supported by any submitters to earlier consultation rounds • Considered to be unworkable
1: Amended status quo	• None	• Not supported by any submitters to earlier consultation rounds • Considered to provide no material improvement over the status quo option
4: Amended kvar charge	• Provides an efficient long run marginal cost based charge against which DTC may consider transmission alternative investments in reactive power support equipment • The similar options 2 and 3 received broad support from submitters in earlier consultation rounds • Should require relatively modest implementation costs and trivial on-going costs • Is simple	• Introduces a minor wealth transfer at the outset

7.5 Assessment against efficiency considerations

7.5.1 The following table compares the main options relative to the status quo. Where possible quantified benefits and cost estimates are included. Positive values indicate an overall efficiency gain in total NPV terms. Where it is not possible to quantify the benefits, a tick represents an improvement relative to the status quo.

Table 5 Assessment of the SRC Options relative to the Status Quo

Efficiency consideration	Amended status quo	kvar charge
Location Pricing	$0	$3.5m - $35m
Implementation & on-going costs	$0	$0.4m – $0.6m
Quantified benefit (NPV 30yr)	**$0**	**$2.9m - $34.6m**
Beneficiary pays	same	✓
Unintended price impacts	same	none-low
Competitive neutrality	same	same or ✓
Good Regulatory Process 1. Wealth transfers 2. Price shock 3. Consistency over grid 4. Consistency over time 5. Workability simplicity 6. Durability (disputes)	all same	✓ ✓ ✓ ✓ ✓ ✓ ✓
Qualitative Score	**X**	✓

7.5.2 Observations:

7.5.3 The amended kvar charge option has the highest net benefit against the status quo option and is qualitatively assessed as being significantly superior to both the status quo and amended status quo option.

7.6 Assumptions supporting the Case for moving to a kvar charge

7.6.1 This option requires that a small component of Transpower's revenue, currently recovered through the interconnection charge, is able to be reallocated for recovery through the new kvar charge. While this does not require that the interconnection charge remains in the TPM in its current form, it is most easily understood if the current interconnection charge (or one that is substantially similar to it) is retained.

7.6.2 It does not require that specific grid assets or new investments are identified.

7.7 Conclusion

7.7.1 There is a case to introduce a kvar charge within the TPM.