Appendix 2

Further analysis including consideration of stage 1 submissions and assessment of high level options

Prepared by the Electricity Commission

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Glossary of abbreviations and terms

AC	alternating current
Act	Electricity Act 1992
AMD	anytime maximum demand
AMI	anytime maximum injection
ANP	augmented nodal pricing
Authority	Electricity Authority
Bill	Electricity Industry Bill
Code	Industry Participation Code
Commission	Electricity Commission
CRNP	cost reflective network pricing
DCR	HVDC rate
ENA	Electricity Networks Association
Frontier report	*Identification of high-level options and filtering criteria,* Frontier Economics
FTR	financial transmission rights
GIT	grid investment test
GPS	Government Policy Statement on Electricity Governance
GSC	grid support contract
GXP	grid exit point
HAMI	historical anytime maximum injections
HVDC	high voltage direct current
ICRP	investment cost related pricing
Issues Paper	issues paper in Electricity Governance Rules, 2003, Part F, Section IV, rule 4
LRA	locational rental allocation
LRMC	long-run marginal cost
MDL	Maui Development Ltd
MDP	Market Development Programme
MEUG	Major Energy Users' Group
MRP	Mighty River Power

NAaN	North Auckland and Northland grid upgrade proposal as approved by the Commission in 2009
NERA Report	New Zealand Transmission Pricing Project, NERA , August 2009
NIGU	North Island Grid upgrade proposal as approved by the Commission in 2008
ORC	optimised replacement cost
PJM	Pennsylvania-New Jersey-Maryland
Pricing Principles	Pricing Principles as set out in Section IV of Part F of the Rules unless otherwise referring to the Pricing Principles set out in the Government Policy Statement on Electricity Governance.
RCPD	regional coincident peak demand
Regulations	Electricity Governance Regulations 2003
review	Transmission Pricing Review
RFP	request for proposals
Rules	Electricity Governance Rules 2003
SOO	Statement of Opportunities
SRMC	short-run marginal cost
stage 1 consultation paper	Transmission Pricing Review: High Level Options consultation paper
stage 2 consultation paper	Transmission Pricing Review: Stage 2 Options consultation paper
summary of submissions	Transmission Pricing Review: high-level options summary of submissions
TPM	Transmission Pricing Methodology
TPS	tilted postage stamp
TPTG	Transmission Pricing Technical Group
USG	unconditional service guarantee
WPI	Winstone Pulp International

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1. Introduction and purpose of this paper

1.1.1 This paper has been prepared as part of Stage 2 of the Commission's Transmission Pricing Review (**review**). It forms an appendix to the *Transmission Pricing Review: Stage 2 Options* consultation paper (**stage 2 consultation paper**). The stage 2 consultation paper contains further analysis – particularly on the potential benefits of locational signalling and draws further conclusions.

1.1.2 Stage 1 of the review was concerned with the formulation of high-level options for transmission pricing. This culminated in the publication of a consultation paper by the Commission in October 2009 entitled *Transmission Pricing Review: High Level Options* (**stage 1 consultation paper**). Attached to the stage 1 consultation paper was a report by Frontier Economics entitled *Identification of high-level options and filtering criteria* (**Frontier report**)[1], which proposed high-level options for transmission pricing and a number of criteria for short-listing or 'filtering' the high-level options. *Transmission Pricing Review: high-level options summary of submissions (**summary of submissions**)* was published in March 2010. All three of these papers are available on the Commission's website.[2]

1.1.3 Stage 2 of the review involves more detailed analysis of the high-level options to form a list of options for consultation and further development. Finally, Stage 3 of the review will involve identification and evaluation of a preferred option and where change is recommended the preparation of a Rule 4 Issues Paper[3] setting out the draft process and draft guidelines.

1.1.4 The purpose of this paper is to:

- detail considerations of submitters' views on the Stage 1 consultation;
- detail further analysis and considerations carried out in Stage 2; and
- describe the thinking behind some of the conclusions drawn in the stage 2 consultation paper.

1.1.5 This structure of this paper broadly follows the structure of the stage 1 consultation paper.

- Section 2 discusses review framework issues
- Section 3 reviews the filtering criteria proposed in the Commission's stage 1 consultation paper

[1] Identification of high-level options and filtering criteria, Frontier Economics, October 2009 available at: http://www.electricitycommission.govt.nz/pdfs/opdev/mdp/consultation/TRP-App2.pdf

[2] http://www.electricitycommission.govt.nz/opdev/transmis/tpr

[3] Rule 4, Part F of the Electricity Goverance Rules.

- Section 4 sets out the high-level options identified in the stage 1 consultation paper and discusses additional options raised in stakeholder submissions and the work undertaken for the CEO Forum
- Section 5 assesses all high-level options.
- Section 6 discusses the further issues set out in the Stage 1 consultation paper: connection charging arrangements, the treatment of transmission alternatives, price-service links and static reactive power compensation.

2. Review of Framework issues

2.1 Introduction

2.1.1 Frontier's approach to deriving high-level transmission pricing options involved the following process:

- reviewing efficient pricing theory
- reviewing international experience
- considering issues with the current transmission pricing methodology
- limiting the scope of high-level options to matters of locational cost allocation; and
- having regard to relevant policy and regulatory considerations.

2.1.2 This section sets out views of submitters and Commission considerations on issues raised in the Frontier report.

2.2 Reviewing efficient pricing theory – the need for locational pricing signals

2.2.1 The Frontier report considered whether the transmission pricing methodology needed to provide locational signals to generators and loads given other key design features of the New Zealand market, particularly nodal pricing. The Frontier report examined this issue in two contexts:

- use of the existing transmission network by existing generators and loads – which is a function of participants' electricity production and consumption decisions; and
- investment in new load and generation projects – which will influence future demands on the transmission network and the need for transmission investment.

2.2.2 The Frontier report did not consider whether nodal price signals could provide signals that would facilitate efficient investment in new transmission projects. This is because the review has assumed that transmission investment decisions would continue to be made in accordance with the process and criteria set out in the Electricity Governance Rules 2003 (R**ules**), including the application of the Grid Investment Test (**GIT**). However, the Commission recognises that transmission investment and participant investment influence one another. Signals for efficient investment by participants in load and generation projects will help ensure that the GIT supports efficient transmission investment, which should in turn reinforce signals for efficient participant investment.

Efficient use of the existing network

Frontier report

2.2.3 The Frontier report drew on the earlier Frontier paper entitled "Theory of efficient pricing for electricity transmission[4]" to explain that in an energy-only market with 'full' nodal pricing – incorporating full pricing of congestion and losses and appropriate scarcity pricing – generators and loads would face appropriate signals for the use of the existing network. That is, full nodal pricing would provide participants with economically correct signals for their electricity consumption and production decisions. However, the Frontier report noted that full nodal pricing is not presently in place in New Zealand because the spot market price does not reach the value of unserved energy at times of supply scarcity.

Views of submitters

2.2.4 Frontier suggested the adequacy of nodal pricing for efficient participant operating decisions as a relatively uncontroversial proposition. Submitters largely agreed that full nodal pricing provided sufficient signals for efficient dispatch of generators.[5] However, several submitters (including Transpower, Northpower and Contact) contended that nodal pricing is not particularly effective for providing efficient consumption signals. This is because most consumers do not have time of use metering and hence do not face time of use energy prices. More broadly, Todd Energy considered that economies of scale in transmission, generation and load investment implied that nodal prices alone would not provide appropriate signals for the efficient use of the transmission network.

Commission considerations

2.2.5 While it is true that consumers who do not face time of use prices lack the same incentives to consume efficiently as those consumers that do have time of use meters, this is not a shortcoming of a nodal market design but a limitation of the existing industry structure, metering infrastructure and retail tariffs. Therefore, the Commission considers that full nodal pricing – if implemented – would provide appropriate signals at the wholesale market level for the use of the transmission

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[4] Theory of efficient pricing for electricity transmission, Frontier Economics, July 2009, http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpr/Efficient-pricing-theory-report.pdf

[5] Contact referred to 'excessive' or 'disproportionate' signals arising due to the 'springwasher effect'. But the nodal prices emerging in a network loop that is experiencing a binding constraint (giving rise to the 'springwasher effect') are efficient, albeit unintuitive. Having said that, it would appear inconsistent for nodal prices to rise above the value of unserved energy at nodes where load remains connected.

network. Separate Commission projects are focussed on addressing the lack of pricing signals at times of supply scarcity in the New Zealand market[6].

Efficient investment by generators and loads

Frontier report

2.2.6 The Frontier report also suggested that under certain conditions, full nodal pricing could provide efficient signals for new investment in generation and load. If transmission investment does not exhibit non-divisibility (also known as 'lumpiness') or economies of scale and if it occurs in a manner and at a time that maximises net economic benefits (ie if the economic benefits limb of the GIT is applied to all transmission investments), nodal prices will provide efficient signals to investors in generation and load projects. Under these conditions, there would be no need for transmission pricing methodology to provide locational or other signals to investors.

2.2.7 However, the Frontier report noted that nodal pricing may not provide efficient investment signals (in terms of location, timing and technology) if these conditions did not hold. In particular, if inefficient over-investment in transmission occurs due to the need to meet non-economically-based deterministic reliability standards or due to the over-caution of network planners, nodal price differentials will tend to be inefficiently 'muted'. This would tend to have two effects. First, it would potentially pre-empt or 'crowd out' more efficient non-network solutions that might emerge in response to market signals. Second, it would 'undersignal' the value of participants locating in areas where they are less likely to bring forward augmentation of the transmission grid. Under these conditions, the Frontier report argued that some mechanism or pricing regime would be needed to augment or supplement nodal prices in order to promote efficient generation and load investment decisions (see section 2.1.1, pp.4-5.)

2.2.8 In this context, it is worth noting that the Frontier report sought to differentiate between inefficient and efficient over-investment. Investment in excess of forecast needs is inefficient if it reflects:

- The satisfaction of reliability standards that imply a higher value of unserved energy than is actually the case – for example, it may be that applying an N-2 standard at Kaitaia implies a value of unserved energy of $100,000/MWh, when the true value is $10,000/MWh; or

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[6] Commission projects are considering the development of scarcity pricing and default buy-back mechanisms. The Commission is also providing input to the Ministry of Economic Development project determining how and when Whirinaki should be removed from the Reserve Energy scheme.

- A systematic bias of the network planner towards over-stating the risks or costs of unserved energy – described as 'over cautiousness'.

2.2.9 Transmission investment is not inefficient if it is justified on the basis of avoiding the high cost of a small risk of unserved energy, so long as the calculation of such costs and risks is reasonable.

2.2.10 One remaining area of contention is whether efficient over-investment due to economies of scale can lead to nodal prices failing to provide adequate signals for new load and generation. The literature on this point suggests that while both lumpiness and economies of scale may lead to a temporary (post-investment) muting of nodal price differentials, in a long term dynamic context, they do not imply that nodal prices would be systematically distorted.[7]

Views of submitters

Role of nodal pricing

2.2.11 Submitters had mixed views as to the adequacy of nodal prices for providing efficient locational signals to investors in load and generation. Most parties considered that nodal prices did provide some locational signals for new generation (Meridian, Powerco, Contact, Orion). In particular, Meridian Energy and Powerco suggested that nodal pricing combined with the operation of the GIT and deep connection charges provided fairly reasonable signals. Other submitters, such as Winstone Pulp International (**WPI**), Mighty River Power (**MRP**) and Todd Energy suggested that the conditions for nodal pricing to provide efficient investment signals were not currently met in the New Zealand market and were unlikely to be achievable.

2.2.12 Several submitters (Northpower, Vector, Major Energy Users' Group (**MEUG**), Electricity Networks Association (**ENA**) considered that nodal prices had either a weak or a even inappropriate influence on investment decisions, implying a need for stronger location-based transmission pricing signals. For example, Northpower noted that the 'lumpiness' of new generation was such that a generator investing on the basis of a high nodal price may cause the price to fall, undermining the viability of its investment. Similarly, loads cutting back their demand may cause the price to fall, but the benefits are experienced by other

[7] See Perez-Arriaga, I.J., F.J. Rubio, J.F. Puerta, J.Arceluz, J.Marin, "Marginal Pricing of Transmission Services: An Analysis of Cost Recovery", *IEEE Transactions on Power Systems*, Vol. 10, No.1, February 1995, pp.546-553, available here. In practice, the issue seems to turn on whether transmission investment exhibits permanently declining average total costs (which suggests that nodal price rentals will always under-recover fixed transmission costs and hence that an additional means to signal and recover outstanding fixed costs is required), or whether transmission investment exhibits more limited economies of scale within technology types, similar to generation investment (which can, at least in theory, recover its fixed costs in an energy-only spot market and hence require no additional signal or charge in the long run).

loads that take no action. ENA agreed, contending that nodal pricing provides weak and inappropriate locational signals, particularly as nodal price ‘collapse’ most strongly affects embedded generation and demand-side management options. Some of the same submitters (Northpower, ENA) pointed to wind farms being developed in remote parts of the South Island rather than near Auckland as evidence that current locational signals were inadequate.

2.2.13 Finally, some parties (Transpower, Orion, Contact) believed that other factors were more important to locational investment decisions than nodal prices. This was particularly the case for new loads.

Evidence of excessive or premature transmission investment

2.2.14 On the issue of whether nodal prices had been inappropriately suppressed in New Zealand due to excessive or premature transmission investment most submitters suggested this had not been the case. Three parties considered that nodal prices were inappropriately suppressed, but that it did not mean they thought that transmission investment was occurring too early. While several parties acknowledged that transmission investment had suppressed nodal price differences, they generally suggested that this was appropriate due to imperfect foresight and the asymmetric costs of under-investment compared to the costs of over-investment, as well as the presence of economies of scale (Orion, Contact, Meridian, MRP, WPI, Transpower). A few submitters also suggested that transmission investment had occurred too late in New Zealand rather than too early (Northpower, MRP, Transpower).

Who should face locational transmission prices?

2.2.15 Several submitters contended that generators should face locationally-differentiated transmission charges, while the benefit of imposing such charges on loads was limited (Northpower, Contact, Transpower). This was primarily because most loads are not in a position to respond to locational transmission pricing signals. Those loads that are large enough for transmission costs to materially affect locational decisions would probably also be in a position to by-pass the grid altogether.

2.2.16 Other submitters suggested empirical testing of the impact of locational charges on participants was necessary to answer this question (Meridian, MRP).

Adequacy of existing signals from nodal pricing, the GIT and deep connection charges

2.2.17 The majority of submitters believed that generators face insufficient locational signals under the current energy and transmission pricing regime. While some submitters noted that the High Voltage Direct Current (**HVDC**) provided some locational signals to new generators (Powerco, MRP), others suggested the HVDC charge was inappropriately deterring new generation investment in the upper South Island (Contact). Similarly, Meridian considered that the existing arrangements would provide more appropriate locational signals without the HVDC charge.

Commission considerations

2.2.18 Since the publication of the stage 1 consultation paper, the Commission has undertaken empirical analysis to understand the extent to which enhanced locational signalling could incentivise co-optimised investment in transmission and generation-. This analysis is discussed in the stage 2 consultation paper and Appendix 3.

2.2.19 Nevertheless, the Commission considers it worthwhile to make some in-principle observations in response to submitters' views.

2.2.20 First, the lumpiness of generation and demand-side options that gives rise to the 'price collapse' phenomenon is a problem for all energy-only market designs, not just those that incorporate nodal pricing. Investors in any market where investment is lumpy typically either enter contracts with other parties likely to benefit from the investment to underwrite the financial viability of their investment or make their investment on the basis of expected post-entry prices. Depending on the extent of lumpiness, this may not lead to significant inefficiency in the timing or nature of investment compared to the textbook case of an omniscient social planner. This is because while a lumpy investment may lead to a price collapse in the short term, investors expect to be able to earn higher prices over time as demand grows and before new plant are commissioned. Further, under the existing design of the New Zealand market, if the risk of price collapse at a particular node is so severe that efficient investment does not proceed (ie there is 'market failure'), Transpower would have the ability to approve or contract for network support services justified through the application of the GIT. The question is thus whether a locationally-differentiated transmission pricing could provide a useful adjunct to nodal pricing and the GIT to help avoid any inefficiencies caused by lumpiness.

2.2.21 Second, it may be that other factors are more important to locational decisions than nodal prices. This may be either because nodal prices do not adequately reflect transmission costs, or because the importance of transmission costs to locational decisions is relatively low. If the latter is the case, then changing the transmission pricing methodology may not have much impact on locational decisions. However, if the former applies, it may be worth implementing a different transmission pricing methodology so that participants face the full costs of transmission when making investment decisions.

2.2.22 Third, as a result of the above point, it is extremely difficult to infer the adequacy or otherwise of locational signals from the occurrence of particular generation or load investments (such as wind generation in the South Island). As noted by some submitters, such investments are driven by a combination of factors and the net result may be investments that significantly diverge from the pattern of investment that would be expected based on the relative magnitude of transmission costs alone. However, this does not imply that there is no value in setting efficient transmission prices. On the margin, there may be investments for which a change in the transmission pricing methodology beneficially changes the location, timing or technology of the investment. The question is whether the benefits that flow from setting efficient prices are sufficient to exceed any costs of implementing and adjusting to a new methodology.

2.2.23 In this context, a key question is whether the benefits of providing signals outweigh the costs in relation to both sides of the market, or whether it is only worthwhile providing transmission pricing signals to generation (or load). Many submitters commented that loads would be unlikely to respond to transmission signals and hence that it was not worthwhile to subject them to transmission pricing signals.

2.3 Pricing structure

Frontier report

2.3.1 The Frontier report made limited comments on transmission pricing structure issues, preferring to leave those for the subsequent stages of the review. However, the report noted the following:

- The proponent of the ‘tilted postage stamp’ option, Grant Read, had suggested that such charges ought not be structured as a least-distortionary ‘optimal tax’, but in a manner designed to encourage attenuation of load growth – such as in the form of a peak demand charge (section 3.2.1., p.18); and
- Under the augmented nodal pricing approach, the objective is to impose relatively high charges on:
  - new (or expanded) loads in areas of the network and at times during the day and year when drawing power from the network is expected to contribute to the case for future network augmentation; and
  - new (or expanded) generators in areas of the network and at times during the day and year when injecting electricity is expected to contribute to the case for future network augmentation.

2.3.2 At the same time, the Frontier report noted that such transmission charges should not be structured on the basis of actual usage of the transmission network, in terms of MWh injected or withdrawn from the grid. Such volumetric charges could operate as a tax on usage, which would inefficiently deter the utilisation of sunk assets. Better options were said to include charges based on rated or contracted capacity or charges based on peak demand or injections.

2.3.3 The report also highlighted a comment from Grant Read that any transmission pricing regime would distort the signalling role of nodal prices to some extent. In this context, he considered the current focus on peak offtakes and injections represents a reasonable approach for minimising the distortions. According to the Frontier report, one option for improvement could be to base charges on a fixed metric, such as the nameplate or contracted capacity of the relevant load or generator (section 3.1.2, p. 18).

Views of submitters

2.3.4 The stage 1 consultation paper did not directly ask submitters to comment on the appropriate pricing structure. However, submitters were asked whether they agreed it was appropriate for Stage 1 of the Review to focus on higher-level issues (namely locational signalling) and for pricing structure issues to be dealt with at a later stage. As such, stakeholders were divided, with some agreeing with the proposed emphasis of Stage 1 (Northpower, Contact, Meridian, MRP, WPI, ENA and Todd Energy) and others suggesting that pricing structure issues were as important to promoting efficient investment decisions as locational cost allocation (Powerco, Transpower and Panpac). Transpower commented that what could be termed as pricing structure issues – such as the delineation between connection and interconnection nodes – could be as economically significant as locational cost allocation.

Commission’s approach

2.3.5 The form of pricing structure is a key issue for the review. To provide context for the potential pricing structure options, it is first worth outlining the structures that apply to current transmission charges. This is followed by a discussion of a broad range of structural options that could be further explored. Pricing structure is considered in relation to the HVDC charge in section 3.3 of the stage 2 consultation paper and in Appendix 4.

Existing transmission charges pricing structures

2.3.6 The structures of transmission charges under the existing transmission pricing methodology are described below. These descriptions are all based on Schedule F5 of the Electricity Governance Rules.

Connection charge

2.3.7 This charge recovers the regulated capital, operating, maintenance and overhead (for injection customers) costs of connection assets (as defined in Schedule F5). Overall connection costs are allocated to various connection assets based on their respective replacement costs.

2.3.8 If only one customer is connected to interconnection assets through a particular connection asset, that customer will be allocated the entire costs associated with that connection asset.

2.3.9 If more than one customer is connected to interconnection assets through a particular connection asset, the costs associated with that connection asset are allocated on the basis of each relevant customer's anytime maximum demand (**AMD**) and/or anytime maximum injection (**AMI**), as a proportion of the sum of all relevant customers' AMD and AMI. This means that customers that both inject and offtake electricity through particular connection assets are charged in respect of both activities.

- AMD refers to the average of a customer's 12 highest offtakes at that location during the capacity measurement period for the relevant pricing year. A capacity measurement period is the 12 month period ending 31 August in the year immediately prior to the relevant pricing year.
- AMI refers to the average of a customer's 12 highest injections at that location during the capacity measurement period for the relevant pricing year.

2.3.10 Offtake and injection refer to the net quantity of electricity flowing out of or into the grid, respectively, at a particular connection location in a half hour period.

2.3.11 The sum of all connection charges allocated to a customer for all connection assets serving a connection location is that customer's annual connection charge in respect of a pricing year. The customer pays the annual connection charge monthly in equal instalments.

2.3.12 The Rules make provision for a number of modifications and exceptions to the process for determining connection charges, including the scope for prudent discounts.

Interconnection charge

2.3.13 This charge recovers the remainder of Transpower regulated alternating current (**AC**) network revenue that is not recovered from connection charges. This is known as the interconnection revenue for the relevant pricing year.

2.3.14 The interconnection charge is only imposed on offtake customers. An offtake customer's annual interconnection charge at a particular location is based on the product of the customer's average regional coincident peak demand (RCPD) for that customer at that connection location and the Interconnection Rate, and is subject to various potential adjustments.

2.3.15 A customer's RCPD refers to its offtake at a connection location during a regional peak demand period. A regional peak demand period is one of a certain number of regional peak demand half hours in a capacity measurement period.

2.3.16 This number varies according to the region in which the customer is located:

- In the upper North and South Island regions, there are 12 regional peak demand periods in a year.
- In the lower North and South Island regions, there are 100 regional peak demand periods in a year.

2.3.17 This means that a customer's average RCPD is obtained by averaging over more half hours in the lower North and South Island regions than in the upper North and South Island regions. This broad separation into four regions was done to recognise that both the Upper North and South Islands were likely to have systemic generation/load imbalances and so these regions were most likely to require ongoing investment in expensive transmission capacity. The use of twelve peak periods was intended to better influence demand management consistent with efficient use of existing transmission capacity. The Commission believes that the RCPD approach has been successful in this respect.

2.3.18 The Interconnection Rate is the same across all customers (i.e. it is postage stamped) and it is set at a level to ensure all interconnection revenue is recovered. This requires that the Interconnection Rate is equal to the interconnection revenue divided by the sum of the average RCPDs for each customer at a connection location across all customers at all connection locations.

2.3.19 Offtake customers pay the annual interconnection charge in equal monthly instalments.

HVDC charge

2.3.20 The HVDC charge recovers Transpower's HVDC revenue and is paid by customers located in the South Island that inject power into the transmission grid.

2.3.21 A customer's annual HVDC charge in respect of a given pricing year is the product of the customer's historical anytime maximum injections (**HAMI**) and the HVDC rate (**DCR**), and is subject to various potential adjustments.

2.3.22 HAMI refers to the average of the customer's 12 highest injections into the grid at that location during:

- the relevant capacity measurement period or
- any one of the four immediately preceding pricing years, whichever is highest.

2.3.23 The DCR is a postage stamped rate that is set at a level to ensure that all Transpower's HVDC revenue is recovered. This requires that the DCR is set to the HVDC revenue divided by the sum of HAMIs for all South Island generators.

2.3.24 HVDC customers pay the annual HVDC charge in equal monthly instalments.

Alternative pricing structures

2.3.25 The Commission notes that while there is an almost infinite number of variations, potential pricing structures broadly fall within the following categories:

- Actual MWh – Charges based on actual electrical energy offtake or injection quantities (in MWh). For example, a load could be charged based on the sum of its monthly offtakes while a generator could be charged based on the sum of its monthly injections.
- Time of Use MWh – Charges based on the sum of electrical energy offtakes or injections (in MWh) at various times. For example, a load could be charged on the basis of its offtakes during peak times (such as 8am to 6pm working weekdays), or during peak and shoulder times. Similarly, a generator could be charged based on its peak time injections into the grid.
- Peak offtakes/injections MW or MWh – Charges based on a number of peak offtakes or injections over a measurement period. The nature of the peak could be defined in relation to a certain number of half-hours (such that the peaks would be measured in MWh) or a certain level of demand (such that the peaks would be measured in kW).
- Nameplate or contracted MW – Charges based on the registered nameplate capacity (in MW) of generators and maximum contracted demand (also in MW) for loads.

2.3.26 The Commission notes that the peak offtakes/injections approach is broadly the basis for the present connection charge, interconnection charge and HVDC charge. As highlighted above, there are differences in how peak offtakes and injections are calculated for the different existing charges. For example, the number of peak periods used to determine a load's interconnection charge varies by region, with the 12 highest regional demands used to calculate the charge in the upper North and South Island regions and the 100 highest regional demands used in the lower North and South Island regions.[8] Another example is the basis for the HAMI charge, which is effectively based on a South Island generator's 12 peak injections in any year of the previous five.

2.3.27 By way of comparison, National Grid's transmission pricing methodology for loads in the British electricity market utilises a combination of (1) peak demand over the 'triad' and (2) peak offtakes.[9] The triad refers to the three half-hours of highest system peak demand separated by at least 10 days between November and February of each financial year.[10] By contrast, National Grid's standard generation charges are based on contracted Transmission Entry Capacity (in MW).[11]

2.3.28 In the Australian NEM, the National Electricity Rules require that charges for the locational component of transmission tariffs:

> must be based on demand at times of greatest utilisation of the transmission network and for which transmission investment is most likely to be contemplated.[12]

2.3.29 However, the precise structure of such charges is left to the individual transmission business with the approval of the Australian Energy Regulator. Most transmission businesses apply a combination of peak and shoulder or total actual energy charges (in c/kWh) and peak demand charges (in $/kW/day or $/MW/year).[13]

2.4 Treatment of sunk versus new investment

Frontier report

2.4.1 The Frontier report did not explicitly differentiate between sunk and new transmission investments in relation to developing a TPM. This was primarily because under the current regulatory arrangements, the transmission pricing methodology is only designed to recover the costs of transmission assets that

[8] *Electricity Governance Rules*, Schedule F5 (Transmission pricing methodology), clause 3.45.

[9] See National Grid, *The Statement of the Use of System Charging Methodology*, 1 April 2009, available here, para 4.5, p.29.

[10] As above, para 4.10, p.30.

[11] As above, para 5.6, p.35.

[12] National Electricity Rules, clause 6A.23.4(e), available here.

[13] See the current pricing schedules for ElectraNet, Powerlink, VENCorp and TransGrid.

have been commissioned. There is presently no scope for the TPM)to ‘pre-recover’ the costs of future investments that are not yet in existence.

2.4.2 Nevertheless, it may be possible to develop a TPM in which the costs of future transmission investments committed after a certain date are recovered differently from existing assets or investments committed before that date. This was the approach embodied in Grant Read’s ‘ideal contractual framework’ option referred to in his 2007 paper on behalf of MRP. Under Read’s ‘ideal’ approach, historical sunk assets would be recovered through a ‘perfect tax’ while new investment costs would be recovered through take-or-pay contract payments imposed on the beneficiaries of the new investment. The Frontier report noted that Read considered that such an approach was not presently viable in New Zealand in light of the separation now in place between the transmission pricing methodology and transmission investment decisions, which are made pursuant to the GIT process. That said, the augmented nodal pricing option effectively seeks to recover a portion of the costs of excessive or premature network investment from the deemed beneficiaries of the excessive or premature investment. This could be interpreted as adopting a different charging methodology towards new versus sunk assets.

Views of submitters

2.4.3 Northpower was strongly of the view that the costs of sunk investments as well as those that were committed should not be subjected to a changed pricing regime on the basis that these investments could not be avoided even if generation and load behaviour changed. Northpower noted that the tilted postage stamp option makes no distinction between sunk and new assets. Orion commented that a shortcoming of the present TPM is that it is only concerned with the recovery of sunk costs rather than the efficient signalling of future investments. Meridian suggested that empirical analysis be undertaken prior to implementing any new transmission pricing methodology, in part to ensure that a revised TPM does not deter the use of sunk assets – or worse still, strand those assets.

2.4.4 MEUG suggested that the definition of connection costs be made deeper in relation to sunk assets. WPI commented that if locational hedging instruments became available through the Commission’s other work, it may be necessary and appropriate to recover sunk transmission costs in a manner that provided variable locational signals.

Commission’s considerations

2.4.5 The Commission considers there are two distinct but related issues surrounding the question of charges for sunk versus new investments. These are:

- whether the TPM should recover the costs of sunk assets differently from the costs of new investments; and
- whether the TPM should seek to recover sunk asset costs in a way that seeks to influence future participant investment decisions.

2.4.6 The Commission considers that if locational transmission pricing signals are necessary to promote efficient investment decision, the TPM must implement one or both of these cost recovery approaches.

2.4.7 That is, the methodology must either:

- recover (at least a portion of) new investment costs in a different manner to sunk asset costs – as does the augmented nodal pricing option; and/or
- recover sunk costs in a way that seeks to influence future participant investment decisions (in terms of location, timing and technology) – as does the tilted postage stamp option and the load flow-based options.

2.4.8 If neither of these approaches is taken, the TPM will not provide the signals that may be lacking from other aspects of the market design such as nodal pricing.

2.4.9 If the second of these approaches is taken, the question arises as to how charges should be set:

- based on forward-looking information, such as the investment cost related pricing (**ICRP**) load flow approach in Britain; or
- based on historical information, such as the cost reflective network pricing (**CRNP**) load flow approach used in Australia.

2.4.10 The tilted postage stamp approach could similarly be developed either on the basis of expected future power flows or historical flows. It should be noted that even if charges are developed on the basis of historical information, such charges may provide appropriate signals for future decisions.

2.4.11 The Commission considers that the treatment of sunk versus new transmission investment costs is intimately tied up with the choice of transmission pricing methodology. Different treatments of sunk and new assets are compatible with particular pricing options. Therefore, it is not possible to determine the form of treatment independently from the pricing option and the Commission considers it is appropriate that the selection of the appropriate pricing option should determine the form of treatment rather than the reverse.

2.5 International experience

Frontier report

2.5.1 Frontier's international review report[14] examined 15 jurisdictions. The report considered not only the prevailing transmission pricing regime, but also the energy market pricing arrangements.

Views of submitters

2.5.2 Submitters were generally satisfied that the international jurisdictions that were surveyed by Frontier were sufficient to provide a picture of international practice. No submitters suggested further jurisdictions for consideration.

2.5.3 Northpower commented that many of the countries studied were quite different to New Zealand in terms of population density and generation. New Zealand has a relatively small population spread out along a 'long skinny' grid and Norway would be the only country in the selected jurisdictions that comes close to that model. Northpower additionally noted the United Kingdom and Chilean systems may offer a way forward in how transmission costs can be signalled to generators. Pan Pac also wanted to explore the United Kingdom model further.

2.5.4 Contact stated that it is difficult to get a fair comparison to the background, political scene, geography, generation mix, line company mix and market conditions in New Zealand. The specific details and how these compared to the New Zealand situation were not clear but the tradeoffs between locational energy market signals and transmission location signals are consistent.

Commission's considerations

2.5.5 Given the general satisfaction with the international review by Frontier, the Commission considers that it is not necessary to progress further research at this time.

[14] Frontier Economics, *International transmission pricing review*, July 2009 is available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpr

2.6 Issues with the current transmission pricing methodology

Strata report

2.6.1 Strata Energy Consulting prepared a report for the Commission[15] on issues with transmission pricing which was reviewed by Frontier. The stage 1 consultation paper sought views from submitters on whether the issues summarised by Frontier were correct and relevant and whether there were other issues that should be considered at the high-level options stage.

Views of submitters

2.6.2 Submitters' views set out in the summary of submissions – including additional issues suggested by submitters.

Commission's considerations

2.6.3 The additional issues that were raised by submitters are relevant in other contexts and are addressed in this appendix as they arise.

2.7 Scope of the high-level options

Frontier report

2.7.1 In order to distinguish high-level option issues from more detailed considerations, Frontier's approach has been to treat locational cost allocation issues as high-level and price structure issues as lower level. Submitters were asked if they thought that it was appropriate to focus on locational cost allocation issues.

Views of submitters

2.7.2 Most submitters strongly agreed that it is appropriate for the review to consider locational signalling. For some submitters the focus on locational signalling should be extended to all dynamic efficiency considerations such as operational signalling for load, and seeking definitions of connection and interconnection that better encourage appropriate investment decisions. Several submitters commented on the importance of analysis to assess whether locational signals would have an overall benefit on system efficiency.

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[15] A discussion paper concerning transmission pricing issues identified by the TPTG, Strata, July 2009 is available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpr

Commission's considerations

2.7.3 Stage 1 of the review focused on locational cost allocation issues. In progressing stage 2 and stage 3, the Commission is introducing pricing structure issues and has progressed analysis to assess whether locational signals would have an overall benefit on system efficiency. This analysis is described in the stage 2 consultation paper and appendices 3 and 4.

2.8 Relevant policy and regulatory considerations (including Pricing Principles)

Stage 1 Consultation paper

2.8.1 The stage 1 consultation paper set out the relevant policy and regulatory considerations and sought submitters' views on: whether it was appropriate to review the Pricing Principles as set out in Section IV of Part F of the Rules (**Pricing Principles**); and whether there were particular Pricing Principles which ought to be given precedence over others.

Views of submitters

2.8.2 Submitters almost universally hold the view that the Pricing Principles conflict and that this can be problematic. At least half of the submitters contended that the Pricing Principles should be reviewed and a number of submitters view this as fundamental to the review.

2.8.3 MRP and Meridian were the only parties to indicate clear support for not reviewing the Pricing Principles at this stage. Meridian noted there has been detailed consideration of the Pricing Principles and that the economic and legal conclusions reached were unlikely to change. In Meridian's view once a decision had been taken to develop "a particular pricing approach further, a review of the Pricing Principles should be undertaken before the preferred option is developed to the next level of detail".

2.8.4 Nine out of the nineteen submissions clearly favoured a review of the Pricing Principles. Orion considered that a useful addition to the stage 1 consultation paper would be a review of the Commission's earlier decisions in relation to the Pricing Principles, guidelines for Transpower's pricing methodology and for transmission pricing methodologies more generally. The review would summarise the history behind these decisions and outline the reasons why the Commission now considers that changes to these decisions may be required.

2.8.5 Transpower, Meridian and Orion cited previous decisions the Commission has made in relation to the weight that should be given to various Pricing Principles.

As noted above, Meridian submitted that the economic and legal conclusions on the application of the current Pricing Principles were unlikely to change. On the other hand, Transpower cited examples as to why it claimed the Commission's decisions on the application of the Pricing Principles were problematic.

2.8.6 Transpower was concerned that the Commission's decisions with respect to Rules 2.1 ("user pays") and 2.4 ("non-distortionary sunk cost recovery") of section IV of Part F of the Rules[16] were inconsistent with the guidelines which required interconnection charges to be "postage stamp" in nature. Transpower stated that this was clearly consistent with the principle in rule 2.4, but not with the principles in Rules 2.1 and 2.3. In Transpower's view:

> "That this sort of intractable interpretation and application problem can arise is … sufficient reason for reviewing the Pricing Principles with a view to simplifying them and making them more realistic".

2.8.7 Transpower went on to propose a simplified set of principles.

2.8.8 Contact considered that reviewing the Pricing Principles was an "integral part of the review". MEUG considered that the Pricing Principles needed to be reviewed to "make sure they are much clearer that the beneficiaries pay". Powerco submitted that the Pricing Principles were fundamental to the whole process and that a review "should be done taking into account possible changes to statutory objectives and outcomes for the potential new Electricity Market Authority".

2.8.9 The remaining seven submissions were largely silent on the point, although from the commentary in some submissions a position can be inferred. For example, Rio Tinto noted that it was:

> "pleased that the Commission is prepared to consider the impact of the regulatory settings with a view to recommending changes if that is sensible. It is clear that the existing Pricing Principles conflict with each other and the legislative requirement to give effect to the Government Policy Statement on Electricity Sector Governance also creates unnecessary friction."

Commission's considerations and position

2.8.10 In the stage 1 consultation paper, the Commission stated that it considered it was not appropriate to review the Pricing Principles at this time. The Commission noted that, in virtually all circumstances, it is not possible to apply all the principles equally, but any conflicts between the principles can be managed using the process set out in rule 3.

[16] Unless the context requires otherwise, references to the rules in this appendix are to rules in section IV of Part of the rules.

2.8.11 The Commission acknowledges there are some issues with the current Pricing Principles but considers that these issues are inherent in any principles that seek to achieve multiple policy outcomes. Further there are a number of practical and process issues that arise should a review proceed at this time that were largely not considered by submitters.

2.8.12 Despite the level of industry support for a review of the Pricing Principles, the Commission remains of the view that a review of the Pricing Principles is not required at this time.

2.8.13 The reasons for not recommending a review of the Pricing Principles include the following.

(a) A review is not necessary

(i) There is no need to review the Pricing Principles simply because of the issue of inconsistency as this is to be expected with Pricing Principles. This is acknowledged in rule 3 which enables the Commission to make judgments about the weighting to be given to a particular pricing principle. The issue of inconsistency with Pricing Principles has been observed in other jurisdictions.

(ii) Some submitters appear to want to restrict the coverage of the Pricing Principles. However, restrictive Pricing Principles make for inflexibility. Currently, the Rules expressly allow the Commission to focus on particular outcomes by having the guidelines as an additional mechanism for the Commission to achieve these outcomes.

(iii) The Pricing Principles remain consistent with the current government policy settings.

(b) A review is not practical at this time

(i) The divergence in submissions suggests that a review of the Pricing Principles is likely to result in consensus that the number of principles should be reduced, but no consensus as to what those principles should be. The proposal to amend the Pricing Principles appears to be driven, at least in part, by participants wanting a particular outcome and therefore focusing on a particular pricing principle.

(ii) The proposed changes to the legislative and governance arrangements could make the process (including the decision criteria) for reviewing the Pricing Principles and recommending a rule change uncertain. The Electricity Industry Bill (**Bill**) provides for the disestablishment of the Commission and the establishment of the Electricity Authority (**Authority**). From 1 October 2010 the review will be managed by the Authority and be governed by the provisions of the Electricity Industry Act 2010. Although the Commission can anticipate and plan for the changes in the Bill its work is ultimately governed by the provisions of the Electricity Act 1992.

(iii) Reviewing the Pricing Principles now may also unhelpfully pre-empt the decision making of the new Authority. The Bill provides a much narrower objective for the Authority than the Commission's more wide ranging set of objectives. The proposed objective for the Authority is to: "promote competition in, reliable supply by, and the efficient operation of, the electricity industry fro the long-term benefit of consumers ". The Authority's objective is consistent with the objectives of the Commission but with a sharper focus on economic efficiency. The transition to the new regime is further reason not to undertake a review of the Pricing Principles at this time.

(c) That there will be no net benefit in such a review.

(i) While it is accepted that the drafting of the Pricing Principles could be improved, it is doubtful whether the benefits gained would justify the necessary cost of the rule change process, particularly at this time.

3. Reconsideration of filtering criteria

3.1 Frontier report

3.1.1 As noted above, one purpose of this appendix is to review the filtering criteria developed by Frontier in light of the views of submitters. Briefly recapping, Frontier's proposed filtering criteria were:

3.1.2 **Criterion 1**: Optimality of transmission expansion – the extent to which actual transmission network investment precedes or exceeds the efficient level of investment. If transmission expansion is optimal, and full nodal pricing is in place (which, without nodal scarcity pricing, it presently is not in New Zealand), there is no need for any locational transmission pricing methodology.

3.1.3 **Criterion 2**: Theoretical precision – in terms of accurately compensating for the muting of nodal price signals caused by market design or inefficiently excessive or premature network investment.

3.1.4 **Criterion 3**: Impact of locational hedging instruments – the extent to which locational hedging instruments serve to offset or further mute nodal price signals.

3.1.5 **Criterion 4**: Network topology – different pricing approaches are generally better suited to different network topologies, although they can be modified to suit.

3.1.6 **Criterion 5**: Implementation difficulty and information requirements.

3.1.7 **Criterion 6**: Governance – the incentives for particular groups of participants to properly scrutinise network planning decisions.

3.1.8 **Criterion 7**: Good regulatory practice – encompassing minimising subjectivity, enabling replicability and promoting transparency and predictability of network tariffs.

3.1.9 **Criterion 8**: Stakeholder acceptability – as approaches that are unacceptable to a large proportion of participants will tend to be unstable and face pressures for revision over time.

3.1.10 The Stage 1 consultation paper noted that the filtering criteria "could be used for narrowing down the high level options" but that stages 2 and 3 would include closer assessment of the options against Pricing Principles and a cost benefit analysis.

General comments by submitters

3.1.11 Most submitters did not comment directly on Frontier's proposed filtering criteria. Of those that did, many were critical of criterion 1 (observed degree of network overbuild) and several were critical of criterion 3 (impact of locational hedging instruments). Some comments were made in relation to criteria 2 (theoretical precision), 5 (implementation and informational issues), 6 (governance) and 8 (stakeholder acceptability). Submitters' comments on these criteria are discussed below in numerical order of the criteria following an outline of the rationale for each criterion.

3.1.12 In addition, some submitters made general comments in relation to appropriate filtering criteria. Orion suggested that the Commission should use the Part F Pricing Principles instead of developing a new set of filtering criteria. MRP commented that the Frontier criteria were not particularly helpful. Rather, MRP noted that the criteria were ultimately about whether locational pricing will improve efficiency to the long-term benefit of end-users. To this end, MRP suggested the TPM should be designed to satisfy the following six principles (as advocated by Professor Richard Green[17]).

- Promote the efficient day-to-day operation of the bulk power market.
- Signal locational advantages for investment in generation and demand.
- Signal the need for investment in the transmission system.
- Compensate the owners of existing transmission assets.
- Be simple and transparent.
- Be politically implementable.

3.1.13 Meridian suggested that an important criterion was the extent to which a theoretically improved locational signal would be expected to impact on locational decisions in practice and the expected (aggregate generation and transmission) costs of meeting demand. Meridian considered that it may not be worthwhile pursuing theoretical improvements to the methodology if this was not likely to yield tangible benefits in the real world.

3.1.14 Panpac contended that the various options needed to be assessed and compared through a robust mathematical modelling process rather than through qualitative discussion.

3.1.15 Transpower suggested an additional criterion focussing on the extent to which changes in the pricing methodology may increase the scope for disputes.

[17] See Green, R., Electricity transmission pricing: an international comparison, *Utilities Policy*, Vol.6, No.3, pp.177-184 (1997).

Commission considerations

3.1.16 The Commission notes that Professor Green's 'transmission Pricing Principles' cited by MRP were developed in a broader context than TPM as that term is applied in the present New Zealand market arrangements. Therefore, several of the principles are redundant in New Zealand. For example, the promotion of efficient day-to-day operation of the bulk power market in New Zealand is handled through bid-based merit-order security-constrained dispatch with nodal settlement, although certainly the structure of transmission charges should seek not to distort participant bidding behaviour.

3.1.17 The Commission considers that Meridian and Panpac's proposals for more detailed empirical analysis would form part of the second and third stages of the Review.

3.1.18 With respect to Transpower's proposed criterion referring to the scope for disputes, the Commission considers that it is preferable to focus on more objective criteria such as informational requirements, good regulatory practice and stakeholder acceptability. The probability of a pricing methodology option being disputed is likely to be some function of these three criteria and the scope for dispute will be considered under all three criteria.

Criterion 1 – Optimality of transmission expansion

Views of submitters

3.1.19 As noted above, the Frontier report explained that assuming transmission investment was undertaken efficiently and did not exhibit economies of scale or lumpiness, full nodal pricing should provide participants with appropriate signals for investment in load and generation projects. Under these conditions, nodal prices should encourage efficient timing, location and technology of new generators and loads such that transmission, generation and load investments are co-optimised and overall system-wide costs are minimised. However, to the extent that transmission investment occurs "inefficiently" (as opposed to efficient over-investment – see 2.2.8), and where there is no nodal scarcity pricing, nodal price differentials will tend to be muted . In the event that these conditions exist there will be a stronger case for a TPM to include locational signals to compensate.

3.1.20 Several submitters found this criterion controversial. Meridian agreed with the conceptual basis for this criterion, but suggested that transmission investment orientated towards meeting established grid reliability standards (**GRS**) should not be regarded as inefficient just because those standards led to accelerated investment compared to a "theoretically pure just-in-time approach".

3.1.21 MRP objected to criterion 1 on the basis that, contrary to Frontier's rationale (that the more sub-optimal transmission investment is, the greater the benefits of locational pricing):

> the benefit of locational pricing is that it sends signals for new generation and load that would reduce the need for future transmission investment.

3.1.22 Transpower contended that criterion 1 was not particularly useful on the grounds that grid investments are not driven by nodal price differentials. Transpower went on to say:

> Further, the Commission's definition of 'optimal' appears to assume away many of the risks and uncertainties that apply to transmission planning and investment. If uncertainties and the asymmetric risks attached to investing too late rather than too early were properly valued, it would be very difficult to demonstrate that any recent New Zealand transmission investments have been approved too early.

3.1.23 By contrast, WPI appeared to support the rationale for criterion 1. However, WPI commented that ascertaining the extent of any sub-optimal network investment should not be viewed as a standard filtering criterion to stand alongside the others. Rather, the application of criterion 1 helps inform the question of whether better locational signals are likely to be needed in the first instance.

Commission considerations

3.1.24 The Commission acknowledges that this criterion has led to a degree of confusion amongst some stakeholders. Some of these concerns may have stemmed from misunderstandings regarding the role of the filtering criteria in the Review.

3.1.25 Criterion 1 is intended to inform whether any form of locational transmission pricing methodology is necessary. This is the same point raised by WPI above. If full nodal pricing is in place and there is no observed inefficient network investment, a flat postage stamp charge pricing methodology similar to the status quo arrangements could be appropriate. However, if sub-optimal network investment is likely to occur, it suggests a TPM that provides compensatory signals to promote efficient participant investment decisions would be of some value. For this reason, the Commission agrees with WPI that it may be appropriate to apply criterion 1 before it can be determined whether it is worth applying the other criteria – if there is no inefficient overbuilding of transmission and full nodal pricing is adopted[18], energy prices should provide reasonable

[18] A separate Commission project is considering the development of scarcity pricing. At the time of writing, no decision has been made by this project about the possible design of a scarcity pricing mechanism. However, a

locational signals for generation and load investments and any transmission pricing methodology should seek to work as an 'efficient tax'.

3.1.26 Several submitters questioned the definitions of 'optimal' and 'inefficient' transmission investment used to determine the degree of overbuilding relevant to this criterion, it is therefore worth reiterating the comments made in section 2.2 above. That is, that transmission investment is not sub-optimal or inefficient just because it is justified on the basis of avoiding the high cost of a small risk of unserved energy, so long as the calculation of such costs and risks is reasonable. This means that investment based on an objective assessment of the uncertainties and asymmetric risks and costs of investing 'too late' does not constitute 'overbuilding' for the purposes of this criterion. Similarly, transmission investment in excess of forecast needs is not inefficient if it reflects the non-divisibility or 'lumpiness' of transmission investment, or if it reflects economies of scale. In all of these cases, the apparent 'overbuilding' is efficient and could properly be justified under the economic benefits limb of the GIT. This clarification should hopefully address the concerns raised by Transpower.

3.1.27 The point raised by Meridian is slightly different. Meridian suggested that transmission investment needed to meet the GRS should not be regarded as inefficient just because it occurs before it is theoretically optimal. However, as discussed above, the satisfaction of reliability standards that imply a higher value of unserved energy than is actually the case must be inefficient. This is not to say that Transpower should not undertake such investments or should not be permitted to recover their costs. But the implication of such investment going ahead is that nodal prices will provide less efficient signals to investors in generation and load.

3.1.28 The objection to criteria 1 raised by MRP appears to be based on a misunderstanding. The point made in the Frontier report and repeated above is that if transmission investment were efficient, nodal prices would send the theoretically correct locational signals to investors. However, if inefficient overbuilding occurs, nodal prices will not provide appropriate signals and will need to be supplemented in some way. The very purpose of supplementing artificially muted nodal price signals is to encourage investors to make generation and load investments in such a way that would reduce the need for more transmission investment.

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mechanism that introduces national or regional scarcity pricing, rather than nodal scarcity pricing is an option. At this point in the scarcity pricing project there is an initial preference for regional scarcity pricing.

Criterion 2 – Theoretical precision

Views of submitters

3.1.29 This criterion concerns the extent to which a TPM appropriately compensates for the artificial muting of nodal price differentials due to inefficiently excessive or premature network investment in the network.

3.1.30 Transpower criticised this criterion as not particularly useful. Instead, it suggested a criterion concerned with the likely effect of an option on actual consumption and investment behaviour. Transpower highlighted that "some instruments may be theoretically correct, but would not have any actual economic effect in practice" (p.31). This is similar to Meridian's general comment (see above) that one criterion should be the likely magnitude of real-world impacts of a change to the pricing methodology.

Commission considerations

3.1.31 As noted above, Transpower criticised this criterion as not particularly useful. Instead, it suggested a criterion concerned with the likely effect of an option on actual consumption and investment behaviour.

3.1.32 The purpose of the filtering criteria was to help formulate a short-list of high-level options in Stage 2 of the Review. In this context, the theoretical robustness and precision of a high-level option could provide valuable insight into whether the option is likely to yield benefits compared to the existing arrangements.

3.1.33 The purpose of the criteria was not to determine precisely which transmission pricing option should be implemented. The Frontier report noted that the estimation of the net benefits of the short-listed options would be undertaken in Stages 2 and 3 of the Review. Part of this process would involve ensuring that any change from the existing arrangements should offer material net benefits compared to the existing arrangements.

3.1.34 The Commission does not therefore consider that this criterion needs to be modified but will take note of the concerns raised in the application of the criteria.

Criterion 3 – Impact of locational hedging instruments

Views of submitters

3.1.35 As discussed in the Frontier report, the development of locational hedging instruments will also influence the choice of a transmission pricing regime. To the extent that locational hedging instruments serve to offset or further mute nodal price signals, this criterion implies that the transmission pricing regime will need to impose more locationally-differentiated charges.

3.1.36 Transpower labelled this criterion as 'bizarre':

> …because it suggests that if a location hedge is developed that damps locational signals, then locational signals in the TPM should be reinforced. This would indicate that there is something wrong with the overall coherency of the market design framework. Simply, the possibility of ad hoc adjustments of this sort should not be considered seriously, and any locational hedge mechanism that would damp nodal pricing signals should not be introduced.

3.1.37 WPI considered that criterion 3 ought to be removed as it did not properly describe a filtering criterion but a subset of options.

Commission considerations

3.1.38 As noted above, this criterion came under some criticism from Transpower on the basis that the development of locational hedging instruments would be unlikely, in practice, to conflict with the signals provided through the transmission pricing methodology.

3.1.39 The presumption that the Commission would not knowingly implement a TPM that was incompatible with any new locational hedging instruments does not imply that criterion 3 is unnecessary. Rather, the promotion of transparency and good regulatory practice requires that the Commission is explicit about factors that influence its choice of stage 2 options.

3.1.40 Moreover, a key driver for the development of locational hedging has been to improve retail competition. It need not be considered unreasonable for the Commission to choose to compromise the efficiency of the energy pricing signals faced by loads in order to facilitate hedging instruments that promote retail competition.

Criterion 4 Network Topology

3.1.41 Submitters provided no comments.

Criteria 5 – Implementation and informational issues

Views of submitters

3.1.42 This criterion refers to the difficulties and costs of implementing a new TPM.

3.1.43 Transpower commented that criteria 5 should be extended to include consideration and quantification of the compliance costs associated with implementing any changes.

Commission considerations

3.1.44 The Commission agrees with Transpower that the compliance costs associated with implementing any changes ought to be considered and quantified, to the extent possible, as part of selecting a pricing option. The importance of taking account of these costs was the rationale for this criterion.

Criterion 6: Governance

Views of submitters

3.1.45 This criterion concerns the incentives for particular groups of participants to properly scrutinise network planning decisions.

3.1.46 Meridian commented that this may not be a suitable criterion because scrutiny by a third party is implicit in the current arrangements and any potential alternative.

Commission considerations

3.1.47 As noted above, Meridian commented that this may not be a significant factor because scrutiny by a third party is implicit in the current arrangements and any political alternative. The Commission accepts that regardless of the pricing methodology, all stakeholders will have the opportunity to scrutinise transmission investment decisions. However, this is not the same thing as ensuring that different groups of stakeholders have a financial incentive to scrutinise investment decisions.

3.1.48 The Commission's experience to date has been that the degree of participants' involvement in grid investment assessments has been closely linked to whether they would be required to contribute to the recovery of the investment's costs if it were commissioned. For example, the Commission has noted the general lack of interest shown by North Island generators in the regulatory debates concerning the $670 million HVDC upgrade and the evidence of limited analysis by generators of both the $820 million North Island Grid Upgrade (**NIGU**) and the $470 million North Auckland and Northland (**NAaN**) investments.

Criterion 8 – stakeholder acceptability

Views of submitters

3.1.49 The Frontier report suggested that stakeholder acceptability was an important criterion because it is likely to lead to stability and durability of any new arrangements that are implemented.

3.1.50 Submitters' views on the legitimacy of this criterion were mixed. MRP was strongly of the view that the Commission's choice of options should be driven by what is in the best interests of end-users rather than what particular stakeholders or vested interests would prefer. On the other hand, Meridian endorsed this criterion on the grounds that stability of transmission pricing arrangements was required in light of the substantial transmission investment programme going forward. In Meridian's view, such stability will only come about if the methodology is broadly acceptable to all stakeholder groups. In this context, Meridian interpreted acceptability as:

> …not the same thing as horse-trading or ad hoc decision-making. Rather, it requires a focus on applying Pricing Principles consistently, having regard to practical impacts on the combined cost of generation and transmission, and the concept of all stakeholders paying their fair share.

3.1.51 Finally, MEUG suggested that stakeholder acceptability could be a tie-breaking criterion that could be applied if two options performed equally well in terms of delivering net benefits and the other criteria.

Commission considerations

3.1.52 As noted above, submitters were divided on the appropriateness of this criterion. The Commission considers that all submitters made worthwhile points. It is true that, as contended by MRP, the choice of pricing option should not be beholden to the preferences of particular stakeholders. However, the Commission remains of the view that, on balance, broad stakeholder acceptability of the pricing regime should promote stability and durability of the arrangements and regulatory certainty is important for investment to occur. Whether stakeholder acceptability goes quite as far as proposed by Meridian – encompassing the concept of all stakeholders paying their 'fair share' – is less clear. Views of fairness and equity are seldom durable from a regulatory perspective and are unlikely to be broadly shared. Given that the basic design of the current transmission pricing regime has been more or less unchanged for over a decade, a decision to adopt a new regime that significantly changes the incidence of charges (ie leading to substantial wealth transfers) is likely to cause major disruption to participants' businesses even if this results in a more ostensibly equitable allocation of costs.

The cost of this disruption has to be assessed against the benefits of greater allocative and dynamic efficiency.

4. High-level options

4.1.1 This section describes the high-level options and issues raised in the Frontier report, and the additional options raised in stakeholder submissions. The analysis of the most of these options is described in Section 5 and is discussed in section 4.1 of the stage 2 consultation paper.

4.1.2 In the case of four options suggested by submitters the Commission considers that these can be effectively considered in the context of other options or are outside the scope of the review.

4.2 Options discussed in the stage 1 consultation paper

4.2.1 The high-level options raised in the stage 1 consultation paper were as follows.

- Status quo arrangements.
- Tilted postage stamp (**TPS**) and variations.
- Augmented nodal pricing (**ANP**).
- Load flow-based approaches.

4.2.2 In addition, the Frontier report briefly considered a 'deep connection' (or 'but for') charging approach, as employed in several jurisdictions in the United States.

4.2.3 These options were described and discussed in the Frontier report as well as the Commission's stage 1 consultation paper.

4.2.4 Stakeholder submissions on all of these options, along with the Commission's assessment of each of them, are set out in section 5 of this report.

4.3 Options raised in stakeholder submissions

4.3.1 The Commission has also considered the following options (or variations to the above high-level options) raised in stakeholder submissions.

- Options arising from the Electricity Industry's CEO Forum Steering Group based on work by consultants NERA.[19]
- Options put forward by MEUG based on work by consultants NZIER.
- Other options suggested by submitters.

[19] NERA Economic Consulting, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009 (**NERA report**) available at: http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpr/NERA-Report-Dec09.pdf

4.3.2 These stakeholder-proposed options are described further below.

CEO Forum options

4.3.3 The NERA report for the CEO Forum commented that many features of the status quo arrangements are sound. However, NERA argued that the signals provided under the current arrangements may be insufficient to fully reflect the long-run marginal cost (**LRMC**) of transmission investment (p.107). Further, NERA contended that some features of the existing arrangements – such as the HVDC charge and deep connection charges – potentially distort the location and technology of new generation investment.

4.3.4 To address the locational signalling inadequacies of the existing arrangements, NERA proposed several alternative forms of postage stamp pricing. These were:

- Tilted postage stamp pricing (referred to as a conceptual “straw man” TPS methodology).
- Bespoke locational preferences.
- Efficient tax.

“Straw man” TPS methodology

4.3.5 This “straw man” TPS methodology would provide a simple south-north locational signal to new generators (NERA report, pp.73-81) by imposing a relatively higher charge on new generators wishing to locate in the south of New Zealand than those wishing to locate in the north (who could potentially receive a subsidy). NERA considered that this methodology would by justified if it could be empirically demonstrated that network investment in New Zealand is primarily undertaken to facilitate south to north power flows. The magnitude of the charge would be set based on an estimate of the LRMC of transmission of locating a generator at various locations, less the value of short-run marginal cost (**SRMC**) signals provided by nodal price differentials (as determined from historical data). The charge would not be imposed on loads, who would continue to pay the RCPD-based Interconnection Charge. The reason for not imposing the tilted postage stamp charge on loads was that, unlike new generators, new loads were unlikely to locate differently due to locational variation in transmission charges. Finally, NERA warned that the degree of ‘tilt’ in a tilted postage stamp methodology should not be revisited on a regular basis. To do so would undermine the integrity of the locational signals intended to be provided by such a regime. (p.80)

Bespoke locational preferences

4.3.6 This approach would impose locationally circumscribed tilted postage stamp charges, by focusing differential charges more narrowly at locations where the drivers of transmission investment are unambiguous and/or where the location of desired generation investment over the medium term is reasonably clear (NERA report, pp.81-84). This approach was intended to provide a signal to encourage new generators to locate in certain areas over others where the structure of power flows is such that location in the preferred areas is likely to result in lower total costs to serve load. As with NERA's tilted postage stamp methodology, an estimate of nodal price differentials would need to be deducted from the estimated LRMC of transmission costs to ensure no over-signalling of the costs of generation locational decisions.

Efficient tax

4.3.7 The efficient tax approach represents an abandonment of attempts to provide locational signals and focuses on recovering the regulated network revenue with least distortion to participants' operating and investment decisions.

Criteria for choosing methodology

4.3.8 According to NERA, the principal criterion for choosing between these forms of postage stamp pricing is whether an enduring and robust directional characterisation of future network flows was practicable.

4.3.9 Specifically:

- If it could be demonstrated that the primary driver of transmission across New Zealand is to facilitate south to north power flows, the tilted postage stamp approach would be an appropriate means of providing the locational signal missing under the current arrangements.
- If policy-makers were not confident that south to north power flows would predominate throughout New Zealand in the future but were confident about the drivers of transmission investment in particular parts of the network, the bespoke locational preferences approach could be more suitable.[20]
- If no enduring characterisation of network flows and investment drivers could be made, the best option would be an efficient tax approach to charging. In this case, locational signalling would be limited to nodal pricing, deep connection charges and the GIT.

[20] The Commission notes the present need for generation in the north and west of the South Island would not be addressed by a simple north-south tilt.

4.3.10 NERA's analysis of the Commission's 2008 Statement of Opportunities (**SOO**) found that three of the five scenarios in the SOO were consistent with the hypothesis that a significant proportion of transmission investment is driven by the desire to facilitate a south to north 'structural' flow (NERA report, pp.78-79). However, NERA did not reach firm conclusions in this regard.

HVDC charge

4.3.11 In all cases, NERA supported the partial or total elimination of the HVDC charge, with the foregone revenue to be recovered through postage stamp charges on generators and/or loads (NERA report, pp.87-92). NERA's rationale was that if an enduring characterisation of network flows and cost drivers could be established, the signals provided by the HVDC charge could be subsumed in a more general tilted postage stamp regime. Alternatively, if no enduring characterisation was possible, the HVDC charge would distort generator locational decisions and hence should be removed. According to NERA, even recovering the foregone revenue exclusively from loads would be unlikely to have a significant effect on retail electricity prices, less still electricity consumption decisions (p.88). If neither of these options were feasible, NERA suggested an incremental reform could be to change the basis of the charge from peak South Island injections to nameplate capacity in order to reduce the distortionary impact of the charge on investment in peaking capacity (pp.90-91). However, NERA did not consider that the existing basis of the charge would significantly deter peak injections in the South Island and saw no compelling reason for change.

Other proposals

4.3.12 NERA also made a number of comments on other aspects of the transmission pricing and investment arrangements, including:

- the case for a move to 'shallower' connection charges in order to avoid distortions to generator locational decisions arising from the existing deep connection regime, or failing that, modifications to the connection arrangements to overcome the present asymmetric treatment of embedded and grid-connection generators; and
- the case for allowing the GIT to be applied to nationally significant or otherwise beneficial connection assets.

4.3.13 However, NERA acknowledged drawbacks to these proposals and a lack of consensus within the Steering Group as to how to proceed. Therefore, NERA reported that the CEO Forum Working Group considered that these issues did not warrant further investigation in the near term. Many of the issues raised by NERA are discussed in section 6.2 of this appendix.

NZIER reports for MEUG

4.3.14 In its submission to the Commission's stage 1 consultation paper, MEUG referred to a number of suggestions and recommendations made by consultants, NZIER, in a series of reports prepared for the CEO Forum. These reports were attached as appendices to MEUG's submission. One of the NZIER reports critiqued the options put forward in the NERA report prepared for the CEO Forum (Appendix A). Another report set out a number of options for transmission pricing (Appendix B). A third report specifically focused on refuting NERA's analysis and recommendations regarding deep connection charges (Appendix C). The discussion in this section will focus on NZIER's own proposals for transmission pricing options. However, it is worthwhile to commence by briefly outlining NZIER's objections to NERA's proposed options contained in Appendix A to the MEUG submission.

MEUG objections to NERA options (Appendix A)

4.3.15 MEUG began by criticising NERA's proposals to eliminate or modify the HVDC charge and to move from a deep to a shallow connection charging regime. NZIER contended that NERA had simultaneously suggested that locational signals in New Zealand were insufficient while proposing changes that would reduce the locational signals that were currently in place (pp.3-4).

4.3.16 NZIER opposed NERA's proposal to allow long 'stringy' lines currently classed as connection assets to be approved under the GIT and rolled into Transpower's regulated asset base. NZIER argued that the present regime for connection assets promotes efficient investment decision-making by utilising a commercial negotiation framework (pp.4-12). In NZIER's view, a move to a regulated centralised process for determining investment in these assets would be undesirable.

4.3.17 The NZIER report then sought to refute NERA's reasons for eliminating or modifying the HVDC charge. NZIER argued that contrary to NERA's view, the present HVDC charge substantially under-signalled the LRMC of the link (p.13). Further, NZIER suggested that the beneficiaries of the link could quite clearly be identified as South Island generators and North Island loads (pp.13-14). NZIER went on to comment that the HVDC charge does not create an asymmetry of incentives to invest in South Island capacity between incumbent and new generators (pp.15-16). Finally, NZIER defended its proposal that the HVDC could be operated as a merchant transmission link from criticism by NERA that such an arrangement would lead to the under-recovery of the annual financing costs of the link (p.16).

4.3.18 The NZIER report did not express a direct opinion on NERA's postage stamp pricing options, other than to criticise them for incorporating the removal of the HVDC charge and deep connection charging arrangements (pp.17-19).

MEUG transmission pricing options (Appendix B)

4.3.19 In this report, NZIER began by seeking to differentiate its approach to developing a TPM from that adopted by NERA. NZIER argued in favour of a transmission pricing methodology based on a voluntary contracts framework, in which the defining principle of cost allocation is 'beneficiaries pay'. NZIER proceeded to apply this framework to the allocation of the costs of the current HVDC link and the HVDC upgrade, as well as other major upgrades to the shared grid.

HVDC link

4.3.20 In relation to the HVDC link, NZIER argued that South Island generators were the primary beneficiaries of the existing link. According to NZIER, North Island loads did not materially benefit from the existing link because the wholesale spot price in the North Island tended to reflect the LRMC of thermal generation, this being the marginal dispatched plant in the North Island. Therefore, the hypothetical absence or loss of the link would be unlikely to materially impact the wholesale prices paid by North Island loads beyond the short term (p.8). As between South Island generators, NZIER suggested some minor changes to the structure of the existing HVDC charge but did not advocate them forcefully (p.9).

4.3.21 Following from its beneficiary pays charging framework, NZIER proposed two alternative charging regimes for the HVDC link:

- Capacity rights approach – which involves auctioning (physical) rights for generators to be dispatched to the extent that dispatch (or increased dispatch) relies on flows on the HVDC link. Therefore, if a generator would only be dispatched (or if its level of dispatch would be higher) if the HVDC was in operation, that generator would need to procure capacity rights equivalent to that (increased) dispatch in order to achieve that (increased) dispatch. NZIER considered that the auctioning of rights could also be extended to fund the upgrade of the HVDC link (pp.10-11).
- Arbitrageur approach – which involves allowing the owner of the link to trade its capacity by purchasing power in one island and selling it in the other. This would be constrained by a requirement that the owner could not earn more than the weighted average cost of capital and operating costs of the activity (p.11).

Major network upgrades (other than HVDC)

4.3.22 In relation to other major network upgrades, NZIER proposed a 'but-for' charging approach based on the approach used in the Pennsylvania-New Jersey-Maryland (**PJM**) market and briefly discussed in the Commission's stage 1 consultation paper and the Frontier report. Under this approach – which was also grounded in a beneficiary pays framework – the transmission service provider would seek long term contracts with new generators and major new loads to underwrite the costs of upgrades. Connecting parties would receive financial transmission rights (**FTRs**) in exchange for contributing towards the funding of the upgrade (p.12).

4.3.23 NZIER considered that it would not be practicable to apply the but-for approach to small increases in load. The test for whether application of the but-for approach was worthwhile would be whether it was possible to identify the beneficiaries of the investment at reasonable cost. This test could also be applied retrospectively. For example, it could be applied to the costs of the new Whakamaru-Otahuhu line and the NAaN project, which could reasonably be allocated to consumers in and to the north of Auckland. Further, in NZIER's view, consumers were made aware at the relevant time that payment for the upgrade may in future be allocated to beneficiaries (p.12).

4.3.24 NZIER proposed that connecting parties would only be required to fund the cost of the additional capacity they require, even if the transmission operator chooses to build a larger asset to take advantage of economies of scale (p.12).

4.3.25 Finally, NZIER also considered that the but-for approach could be applied to economic as well as reliability investments in the grid (p.12).

Summary of MEUG options

4.3.26 MEUG ultimately put forward five 'packages' of alternative options (labelled A to E). All options retained the current Interconnection Charge, at least for recovery of existing shared network costs. The differences between the options were as follows:.

- Option A – replaced the existing HVDC charge with the capacity rights approach.
- Option B – replaced the existing HVDC charge with the arbitrageur approach.
- Option C – maintained the existing HVDC charge and imposed additional charges based on a but-for approach for new generators and material new loads.
- Option D – replaced the existing HVDC charge with the capacity rights approach and imposed additional charges based on a but-for approach for new generators and material new loads.

- Option E – replaced the existing HVDC charge with the arbitrageur approach and imposed additional charges based on a but-for approach for new generators and material new loads (p.13).

4.3.27 NZIER recommended that Options D and E be considered by the CEO Forum. NZIER contended that both of its proposed approaches for replacing the HVDC charge were relatively clear and simple and would promote decisions surrounding the use of and investment in the HVDC link by the parties best informed to make such decisions (p.13). In addition, NZIER suggested that the arbitrageur approach to HVDC cost recovery would minimise transactions costs and be credible and acceptable to most stakeholders other than Transpower. Transpower's concerns could be addressed by allowing it to divest ownership of the HVDC link to a party willing to accept the risks of expansion. Further, both approaches for replacing the HVDC charge would remove the disincentives to new South Island peaking generation that exist under the status quo and NERA options. NZIER stated:

> Since a genuine peaking plant would only operate when the HVDC flow is from north to south or when the HVDC link is out of service altogether, under both approaches, a South Island peaking plant would not bear any costs of the HVDC link. (p.14)

Other options suggested by submitters

4.3.28 Four submitters made suggestions for alternative high-level options that were not covered by the options outlined in the Frontier paper. Details of their suggestions and the Commission's considerations are given below.

Tariff rates similar to the lines companies

4.3.29 Contact suggested in its submission that tariff rates similar to those of the lines companies might be considered as an alternative to the high-level options presented in the Frontier report. Contact was referring the lines companies' approach to setting tariffs whereby they set fixed tariffs and forecast annual revenues for the year ahead. Transpower calculates its annual revenues in arrears. The aspect of calculating revenue requirement is a matter for Commerce Commission consideration.

4.3.30 Given the Commerce Commission's role in calculating revenue requirements the Commission does not propose to consider this approach further under this review

The 'gas transport model'

4.3.31 WPI suggested that the gas transport model where shippers invest in the pipelines and the costs are paid through wholesale gas rates should be considered as an alternative option.

4.3.32 The models used for gas transmission were considered at a high-level by the TPTG and the Commission in order to assess whether they might be possible models for electricity transmission.

4.3.33 The two New Zealand gas transmission pipeline owners – Vector Transmission and Maui Development Ltd (**MDL**) – use different arrangements for gas transmission pricing – broadly contract carriage and common carriage respectively. MDL's broadly common carriage model is similar to the electricity transmission model. The methodologies have been developed partly to suit the pipeline topologies. Vector's pipelines are more stringy and have more constraint issues. MDL's pipelines have more spare capacity and are more networked. It is expected that, as MDL's lines become more constrained, MDL may move more towards the contract carriage model.

4.3.34 The group noted that Vector Transmission's network is facing considerable constraint issues, and the current pricing model appears to be contributing to a stalemate that is developing whereby Vector Transmission is reluctant to invest significantly in its network without commitment from a major gas consumer (historically a gas-fired power station.)

4.3.35 Members of the TPTG made the observation that the contract carriage model used by Vector Transmission is similar to both the ideal contract arrangement set out by Grant Read and NZIER's HVDC merchant models.

4.3.36 The Commission agrees with the TPTG that the contract carriage model used by Vector Transmission is similar to both the ideal contract arrangement set out by Grant Read and NZIER's HVDC merchant models. As these two options are considered in part 5 of this appendix, the gas models are not considered further .

A review of the connection-interconnection and node-link definitions

4.3.37 In Transpower's submission it considered that a review of the connection-interconnection and node-link definitions could avoid the incentives on transmission customers to prefer investment alternatives that are economically sub-optimal from a national perspective, but which result in lower transmission charges for the customers concerned. This could also examine possible linkages between regional service preferences and zonal interconnection charges.

4.3.38 The Commission acknowledges Transpower's issue and considers that it is appropriate to consider this as part of the next stage of the review as connection-interconnection definitions could be considered regardless of the transmission pricing options chosen.

Grid connected generators to face all costs

4.3.39 ENA suggested that one solution a requirement for all grid-connected generators to face the bulk of all transmission costs, with transitional contractual arrangements that avoid major price shocks for such generators.

4.3.40 The Commission’s stage 2 analysis has considered the benefit or otherwise of locational signals to generators. This analysis is described in the stage 2 consultation paper and Appendices 3 and 4.

5. Assessment of high level options

5.1 Introduction

5.1.1 This section provides the Commission's assessment of the high-level options raised in the Frontier report and in stakeholder submissions against criteria 2 to 8 discussed in section 3.

5.1.2 In light of the discussion in section 3 above, the Commission does not intend to apply criterion 1 separately to each option. Rather, the degree of divergence between actual transmission expansion and optimal transmission expansion (with reference to economic investments) is a matter that the Commission is examining independently of all of the high-level options (refer Appendix 3).

5.1.3 The Commission notes that estimating the degree of divergence between actual and optimal transmission investment and the implications of that divergence for nodal prices and investment outcomes is extremely difficult. Apart from estimating how actual transmission investment has and will in future diverge from optimal levels, locations and timings; estimating the nodal price and investment implications is likely to require making assumptions about generator bidding behaviour and investors' responses to that behaviour. This is a subjective exercise that is likely to prove controversial.

5.1.4 Therefore, the Commission has instead decided to estimate the potential upper bounds of the economic benefits from providing further locational signals through the TPM.

5.1.5 It considers that an appropriate and practical way to do this is to model the difference from two alternative scenarios where:

- transmission interconnection costs are not considered when generation investments are made; and
- generation and transmission investment are perfectly co-optimised i.e. all transmission investment costs were considered in making decisions to invest in generation and the least cost expansion to meet demand is selected (this is a proxy for an 'ideal' locational signal).

5.1.6 The Commission's analysis of the potential benefits to be gained by developing further locational price signals for generators to support economic investments in transmission in the stage 2 consultation paper and Appendix 3.

5.1.7 To date, the Commission's modelling has shown that the benefits of introducing locational transmission pricing signals to signal the costs of economic transmission investment appear to be limited, given current and future generation and transmission expansion options.

5.1.8 A summary of the assessment of the high-level options raised in the Frontier Report against the other seven criteria is set out in Table 1 below.

5.1.9 Conclusions are made on the high-level options suggested by Frontier and on those suggested by submitters in section 4.1 of the stage 2 consultation paper. The conclusions are based on analysis here and further analysis in the stage 2 consultation paper and Appendices 3 and 4.

Table 1: Summary assessment of high-level options

	Status Quo	Tilted Postage Stamp	Augmented Nodal Pricing	Load-flow approaches
Key features	Deep Connection charges. Postage-stamped Interconnection Charge payable by loads. Postage-stamped HVDC charge payable by South Island generators.	Deep Connection charges remain. Magnitude of charges would vary by location (eg zonal or nodal) based on presumed structural flow of power through the network. In general, higher load charges in north than south; higher generation charges in south than north. May involve rolling together of Interconnection and HVDC charges.	Deep Connection charges remain. ANP charges apply in respect of new transmission investment after investment is committed and reflect the benefit or loss to existing participants due to inefficient over-investment. ANP charges to generators highest for those generators likely to benefit most from over-investment (eg peaking generators in south of South Island). ANP charges to loads should be highest for those loads likely to benefit most from over-investment (eg peaky loads in north of North Island).	Deep Connection charges remain but load-flow analysis could be used to delineate connection from interconnection assets (i.e. define assets based on deemed use rather than network topology). Remaining costs recovered based on an engineering estimation of the value of network assets 'used' to convey power from generators to loads. Allocation can be based on existing network costs (as in Australia) or forward-looking costs (as in Britain).
Views of submitters	Some commented that the status quo does not provide adequate locational signals. Some objected to the HVDC charge.	Most widely supported alternative to status quo. Degree of tilt may be difficult to determine and seek agreement on.	Sound in theory but too complicated to apply in practice.	Most submitters rejected this option on the basis that load-flow approaches were complicated contentious and unstable and had been tried before.

	Status Quo	Tilted Postage Stamp	Augmented Nodal Pricing	Load-flow approaches
Theoretical precision	Relies on nodal pricing providing reasonable signals.	Not intended to be theoretically precise, but the greater granularity the greater the precision.	Theoretically well-resolved approach.	Depends on how implemented – could be similar to ANP.
Locational hedging	Compatible with locational hedging instruments that do not mute nodal price signals.	Compatible with a variety of locational hedging instruments and allocations. Greater tilt could compensate for allocations that partially muted nodal pricing signals.	Compatible with locational hedging instruments that do not mute nodal price signals.	Compatible with a variety of locational hedging instruments and allocations. Could compensate for allocations that partially muted nodal pricing signals.
Network topology	Not relevant if nodal pricing signals are reasonable.	Appropriateness tied to broadly linear nature of NZ transmission network and south to north characterisation of power flows.	Compatible with any topology so long as possible to make reliable predictions about future likely beneficiaries of network investment.	Best suited to meshed networks but can be adapted to suit radial networks experiencing lumpy investment.
Implementation difficulty and information requirements	Minimal issues although modifications to the status quo such as a change to the HVDC charge would raise transitional issues.	Depends on how implemented – could vary from very simple (eg latitude-based) to quite complex (eg based on nodal factors). For example, determining LRMCs at different locations in the network could be difficult.	Considerable difficulties – novel approach that requires detailed information about each transmission investment and likely beneficiaries.	Depends on form of approach – could be applied only to the delineation of connection from interconnection assets or could be applied more generally to the allocation of interconnection costs History of use in NZ and elsewhere (Australia, Britain).

	Status Quo	Tilted Postage Stamp	Augmented Nodal Pricing	Load-flow approaches
Governance	Loads have incentives to scrutinise transmission investments. South Island generators' incentives to scrutinise transmission investments would diminish if HVDC charge is removed.	Could give loads and potentially generators incentives to scrutinise transmission investments.	Intended to give loads and potentially generators incentives to scrutinise transmission investments.	Depends on how charges are applied – could give both loads and generators incentives to scrutinise transmission investments.
Good regulatory practice	Preserves long-standing methodology.	Embodies a degree of subjectivity and arbitrariness but could be fairly predictable once tilt is set.	Involves a degree of subjectivity and arbitrariness. Required modelling is likely to be controversial.	Something of a 'black box' but replicable with aid of relevant model and input assumptions.
Stakeholder acceptability (this is based on submitter views on high-level options consultation).	Maintenance of status quo is unlikely to upset most stakeholders. HVDC charge has been controversial.	Likely to command broad support from stakeholders.	Stakeholders almost universally opposed to further development Could be used as part of a hybrid option to inform tilted postage stamp charges.	Unacceptable to most submitters. Could be used solely to delineate connection from interconnection assets or as part of a hybrid option to inform tilted postage stamp charges.

5.2 Status quo

Outline

5.2.1 The existing TPM provides limited locational signals to participants. As noted in the Frontier report, the existing regime comprises the following charges:

- Connection charges – payable by all connected parties in respect of 'connection assets', as defined in sections 3.54-3.61 of Schedule F5 of the Rules.
- Interconnection Charge – payable by loads. The charge payable by a given load is a function of both the postage-stamped Interconnection Rate ($/kW) and the load's weighted-average RCPD. The number of periods of a load's RCPD to be weighted varies by region.
- HVDC Charge – payable by South Island generators. The charge payable by a given generator is a function of both the postage-stamped DC rate ($/kW) and the generator's 12 peak injections over a historical twelve month period.

5.2.2 Thus, under the existing regime, loads pay for the AC interconnected grid while only South Island generators pay for the HVDC assets. All parties pay for their connection assets.

5.2.3 In addition, new transmission investment decisions are subjected to the GIT. The GIT is designed to ensure that transmission investment in interconnection AC and HVDC assets is either:

- the least-cost means of meeting mandatory network reliability standards; or
- the most net beneficial (efficient) option,out of a range of credible options, including transmission alternatives.

Views of submitters

5.2.4 A majority of submitters who expressed a view considered that the status quo arrangements did not provide adequate locational signals, particularly for new generation investment. For example, MEUG and WPI highlighted the shortcomings of nodal pricing as applied in New Zealand as the key reason why the status quo arrangements were inadequate. Counties Power suggested that the cost of grid augmentation needed to be sheeted home to those that caused it. Similarly, Northpower said that a TPM that reflected the LRMC of the grid was required to signal to generators the costs of their locational decisions. Meanwhile, Todd Energy considered that the status quo arrangements could be much improved by providing generators with access to regulated revenue where they co-located with loads.

5.2.5 At the same time, many submitters considered that the status quo provided at least partly appropriate signals. Meridian went furthest in contending that nodal pricing combined with deep connection charging and the GIT provided broadly appropriate locational signals. However, Meridian objected to the HVDC charge on the basis that it was inappropriate in light of the signals provided by the other elements of the TPM and the GIT. The abolition of the HVDC charge was also supported by Transpower.

5.2.6 Some other stakeholders also had specific complaints about the status quo TPM. For example, Powerco and Contact noted that while the HVDC charge provided incentives for new generators not to locate in the South Island, it did not recognise the need for new generation in the upper South Island.

Commission considerations

5.2.7 The Frontier report suggested that the existing transmission pricing regime reflects one approach to balancing the Pricing Principles, in that:

- the Connection Charge reflects the user-pays philosophy embodied in Rule 2.1,
- the Interconnection Charge reflects an attempt to recover sunk costs in a least-distortionary manner (Rule 2.4) while
- the HVDC Charge reflects both a locational signalling priority – that is, to promote generation investment in the North Island as against the South Island (Rules 2.2 and 2.3) – as well as a beneficiary-pays philosophy (Rules 2.1 and 2.2).

5.2.8 The Commission’s stage 1 consultation paper noted Frontier’s observation that the current arrangements are consistent with a belief that there is no need for transmission pricing to provide additional locational signals to participants, given the presence of:

- nodal pricing (albeit not ‘full nodal pricing’, which reflects supply scarcity);
- the structure of the Interconnection Charge;
- the HVDC charge;
- the approach to connection charges; and
- the role of the GIT.

5.2.9 The GIT is relevant because it is the primary tool for assessing the economic merits of new transmission interconnection investments. Therefore, any party (particularly a generator) whose profitability turns on certain transmission investments either proceeding or not proceeding will need to have regard to the likely outcome of a GIT evaluation. For example, a 'remote' generator may only be viable if a transmission investment proceeds and provides additional power transfer capability from the intended location of the remote generator to a major load centre. Therefore, if a GIT assessment finds that a local generation option is more efficient than the network investment and accordingly rejects the network option, this sends a signal to the prospective investor in remote generation not to proceed. Alternatively, a proponent of a 'local' generator may be emboldened to invest if the GIT analysis demonstrates that a transmission investment is not efficient and is rejected.

5.2.10 In this way, the GIT – if it gives transmission alternatives proper consideration – will reinforce the locational signals provided by the pattern of nodal prices and the prevailing TPM and encourage new investment in accordance with the assumptions used in the GIT analysis. Whether this will lead to efficient outcomes will depend on the efficiency and integrity of these other signals.

Filtering criterion 2 (theoretical precision)

5.2.11 The Frontier report noted that if nodal prices in New Zealand are not artificially muted by premature or excessive transmission investment, the key reform to the current TPM to improve its theoretical efficiency would be to consider modification of the HVDC charge. According to Frontier, HVDC revenues could instead be recovered through charges on all generators and/or loads. However, Frontier noted that this would have wholesale price and distributional effects that may be unappealing.[21]

Other filtering criteria

5.2.12 In terms of the other filtering criteria, the status quo methodology performs reasonably well on the basis that nodal scarcity pricing is introduced:

- Criterion 3 (Locational hedging instruments) – the status quo TPM is only appropriate if locational hedging instruments are not developed or allocated in a manner that hedges or otherwise insulates participants from nodal price differentials. In particular, if the locational rental allocation (**LRA**) option is implemented with rental allocations based on current usage (or, to a lesser extent, the hybrid or zonal options), the status quo TPM may not be suitable for ensuring load participants face overall efficient locational signals. Having said that, reliability driven transmission investment may limit those nodal price signals that are driven by constraints – in which case, the status quo

[21] Frontier report, p15.

would perform less well on criteria 1 and 2 irrespective of the choice of location hedging option.

- Criterion 4 (Network topology) – network topology is not relevant if nodal price signals are sufficient to encourage efficient participant investment decisions (which is the basis for accepting the status quo methodology).
- Criterion 5 (Implementation difficulty and information requirements) – the status quo TPM has relatively few informational requirements. There may be some transitional issues if any modifications are undertaken.
- Criterion 6 (Governance) – the status quo TPM provides financial incentives to particular loads to scrutinise transmission investment decisions that are intended to serve other loads. The TPM also provides incentives to South Island generators to closely scrutinise new HVDC investment. This may be diminished if the HVDC charge were modified or if the HVDC charge were replaced with a general charge on all generators. This is because many South Island generators (specifically, hydro plant) are not in a position to pass-on the HVDC charge through their bids, whereas if the charge was on all generators it would be more likely to be passed on to consumers. Finally, all generators have the incentive to support transmission investments that they consider will benefit them.
- Criterion 7 (Good regulatory practice) – the status quo TPM has broadly been in place for a decade, leaving aside some structural changes to the Interconnection Charge (the use of RCPD) and some relatively minor changes to the HVDC charge and the delineation of connection and interconnection assets. Experience with the status quo has increased the transparency and predictability of network tariffs.
- Criterion 8 (Stakeholder acceptability) – maintenance of the existing regime is unlikely to greatly upset stakeholders or give rise to disputes, although the HVDC charge has been controversial. At the same time, many participants would object to steps to recover HVDC costs from load.

5.3 Tilted postage stamp (TPS)

Outline

5.3.1 The Frontier report discussed a TPS stamp option proposed by Grant Read in 2007, in which charges would be higher for loads in importing regions and lower for loads in exporting regions. If future load growth in New Zealand follows historical trends, Read suggested that charges should be higher for loads in the North Island than loads in the South Island. The rationale for this methodology was that nodal pricing provides insufficient locational investment signals to participants even in the absence of any inefficient overbuilding of transmission. The need for such differentiated charges would be even greater if the transmission system was augmented on the basis of deterministic reliability criteria and if nodal scarcity pricing is not introduced.

5.3.2 In his 2007 paper[22], Read also proposed that the TPS charge could also apply to generators in an inverse manner. That is, generators in the North Island face a lower charge (or even a subsidy) than generators in the South Island. While he noted this would be controversial, he said:

> …if the purpose of an LRMC driven regime is supposed to be long run economic signalling, then generator charging cannot really be taken off the agenda. If, as seems likely, generators are actually more sensitive to locational signals than loads, then most of the potential gains from such a regime may not be realised unless locational signals are provided for generation. And it is difficult to see how any regime can provide locational incentives for generation without charging, or crediting, generation in some way. (para 64, pp.31-32)

5.3.3 Read outlined various means of implementing a TPS methodology, including:

- A linear TPS with the degree of tilt based on latitude and possibly distance from the north-south 'backbone' grid through New Zealand;
- A multi-zone postage stamp based on the grouping of participants' grid exit points (**GXP**s) within geographic zones; and
- Two intra-island postage stamps, effectively treating each island as a pricing zone.

5.3.4 The Frontier report noted that Read outlined the scope for more complicated approaches in which network 'branches' and loops are also taken into account.[23]

5.3.5 In all cases, the slope of the tilt in a TPS methodology would need to be determined, Read suggested the slope should seek to reflect the LRMC of load growth at different locations. Read did not offer a methodology for deriving LRMCs, but he did make the following observations:

> Clearly, it depends on projections of both load and generation growth, transmission expansion requirements and costs. But it is also heavily dependent on other aspects of the regime, such as:
>
> - The extent to which expected spot price differentials will automatically rise to provide locational signalling as transmission capacity becomes tight;

[22] "Locational Transmission Pricing: A Formulaic Approach" prepared for MRP, available at http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpr/Locational-Transmission-pricing.pdf

[23] This would address the Commission's point in footnote 20 regarding the north-south tilt.

- The degree to which charges are actually based on, and hence (dis-) incentivise, certain aspects of load behaviour;
- And, since it is long term behaviour which we wish to incentivise, the extent to which end consumers look ahead when making investment or behavioural choices is also relevant. (para 48, p.24)

5.3.6 The Commission notes that the NERA report puts forward a methodology for deriving locational LRMCs as part of their proposed version of a TPS option. This option is discussed in section 5.6 below.

Views of submitters

5.3.7 Of the four high-level options outlined by the Commission, this option received the widest support from submitters as the most practical alternative to the status quo and the best candidate for further development (although there was significant support for further work on options put forward by MEUG, which are discussed in section 5.7 below).

5.3.8 Of those submitters that gave an opinion, seven supported the view that Read's TPS provided a reasonable trade-off between simplicity and meeting signalling objectives. Four submitters did not believe a TPS model was appropriate. Submitters also referred to the work of the CEO Forum on TPS models and encouraged the Commission to consider this work.

5.3.9 Submitters expressed the following specific comments and concerns about the option:

- It would most likely be successful with very small zones, which would effectively merge this approach with load-flow analysis models (Counties Power).
- That simplicity was less important than reflecting the LRMC of the grid to generators making locational decisions (Northpower).
- It might be difficult to set the tilt (and gain consensus) (Contact).
- That the choice of the amount of tilt should be based on forward-looking considerations, rather than simply reflecting the current grid configuration (Orion) and should not influence the operation of sunk assets (Meridian).
- There will need to be a mechanism to change the tilt over time. TPS approaches may prove difficult to adapt should generation and load patterns change. The durability would be in question (Meridian).
- Conceptually the creation of regional pricing loads (similar to the old South Island differentials) implies an undesirable rigidity that will lead to investment distortions.

- TPS rates should not be applied to loads (MRP, Transpower).
- TPS approaches are unlikely to be theoretically precise and may prove difficult to adapt (MEUG).
- An underlying gross GXP model could be used to set the extent of the tilt in recognition of the transmission benefits provided by local/distributed generation (Todd Energy).

Commission considerations

Criterion 2 (Theoretical precision)

5.3.10 The Frontier report noted that:

> Tilted postage stamp approaches are unlikely to be theoretically precise because a participant's distance from the main grid, or its longitude or latitude, do not bear a linear relationship to transmission costs and needs in New Zealand, given the extreme variations in geography and resource locations. (p.40)

5.3.11 Grant Read specifically developed the TPS option as a 'formula-based' compromise for a market and institutional environment in which his 'ideal contractual framework' was unachievable. He did not claim that this option represented the most theoretically 'correct' pricing methodology. The case for pursuing this option is built on the other criteria. However, the TPS option could be undertaken in ways that were more or less theoretically precise.

Criterion 3 (Locational hedging instruments)

5.3.12 Depending on the precise form it took, the TPS option could be compatible with a number of different styles of locational hedging instrument. If the TPS reflected a gradual linear tilt from south to north, it could partly (albeit crudely) compensate for any loss of nodal price signals due to the adoption of a locational hedging approach. This would require the slope of the tilt to be exaggerated beyond what it would be if there was no loss of nodal pricing signals.

5.3.13 It is possible that the adoption of a TPS based on island-wide zones would potentially duplicate the signals from a hybrid locational hedging instrument, in that both mechanisms would only provide loads with inter-island signals and not provide any intra-island signals.

Criterion 4 (Network topology)

5.3.14 The suitability of a TPS approach to New Zealand is intimately tied to the broadly linear nature of the transmission network and the characterisation of the role of the network as facilitating the transfer of power from south to north. The point was also highlighted in the NERA report for the CEO Forum in respect of their proposed version of a TPS option.

Criterion 5 (Implementation difficulty and information requirements)

5.3.15 A TPS methodology would require some effort to implement. The extent of this effort would depend on the sophistication of the methodology. Read noted that the simplest approach to implementation would be a latitude-based charge, ignoring an east-west dimension and other complications. A more sophisticated approach would take account of east-west distance from the physical ‘backbone’ of the grid, although even this would not fully address the lack of generation in the north and west of the South Island, nor the increasing levels of generation in the lower North Island.

5.3.16 In all cases, determining the LRMCs of different locations would likely be a substantial exercise with high potential for affected parties to dispute or seek to influence key assumptions relating to future demand, generation and transmission development scenarios. A pricing methodology that is based on the LRMCs might also be easily discredited if the key assumptions were inaccurate – for example, after five years of a pricing methodology, the power flows in a hydro-thermal based system such as New Zealand could shift significantly.

Criterion 6 (Governance)

5.3.17 Read’s TPS option was focussed on application to loads, although he suggested it should ideally also be applied to generators. Depending on the allocation of the charge, it could give loads and potentially generators financial incentives to efficiently scrutinise transmission investment decisions.

Criterion 7 (Good regulatory practice)

5.3.18 The Frontier report noted that TPS approaches involve a degree of subjectivity and arbitrariness. There is also a risk that the methodology could be discredited within a small to medium time frame could be large if power flows shift. The determination of the LRMCs of offtakes and injections at different locations on the transmission system is likely to be complicated and difficult to undertake transparently. If a zonal approach to setting charges were adopted, the determination of the boundaries of those zones would also necessarily involve a degree of arbitrariness and create disproportionate locational signals near the boundaries of such zones.

Criterion 8 (Stakeholder acceptability)

5.3.19 It appears from submitters' responses to the Commission's stage 1 consultation paper and work undertaken on behalf of the CEO Forum that some form of TPS option would command broad support from stakeholders.

5.4 Augmented nodal pricing

Outline

5.4.1 The Frontier report outlined this option, which is specifically designed to compensate for the muting of nodal pricing signals resulting from inefficient transmission development. Frontier suggested that "the logical [transmission pricing] response to over-building of the transmission system would be to amplify or otherwise augment nodal price differentials." (section 3.3.1, p.20). The absence of 'full' nodal pricing – specifically, the lack of signalling of consumers' value of unserved energy at times of supply scarcity – would be an additional grounds for supplementing nodal price differentials.

5.4.2 The Frontier report suggested that under the augmented nodal option, transmission charges in respect of new transmission investment would be imposed in the following manner:

- Transmission charges to generators should be highest for those generators that benefit most from excessive or premature network investment (e.g. generators in generation-rich areas who benefit through nodal prices being higher than would otherwise be the case).
- Transmission charges to loads in the same (generation-rich) areas should be relatively low, as those loads are effectively penalised by higher nodal prices caused by over-investment in the network.
- Transmission charges to generators should be relatively low (or negative) in areas where generators are most worse off due to excessive or premature network investment (e.g. generators located in load-rich areas, which experience lower nodal prices than would otherwise be the case).
- Likewise, transmission charges to loads in load-rich areas should be relatively high to reflect the value of the benefit these loads receive through nodal prices being lower than would be the case if transmission investment was undertaken efficiently.

5.4.3 In all cases, charges (and/or rebates) would be imposed after the excessive or premature investment has been committed and would reflect the value of the benefit or loss to existing generators and loads accruing due to the excessive or premature nature of the investment.

5.4.4 It is important to note that locational charges under the ANP approach should only apply in respect of new transmission investments and to the extent that (if at all) each investment exceeds the optimal capacity or precedes the optimal timing. Therefore, if all transmission investment is optimal, no locational charges would apply.[24]

5.4.5 Under this option, the transmission business could (but need not) become entitled to all transmission rentals, in which case the rentals would become a core means of the business's cost recovery. In net terms, the augmented nodal charges recovered from participants should reflect the sum that would not be expected to be recovered through the transmission rentals attributable to the investment going forward. Together, the rentals on new transmission investments plus the augmented nodal charges should enable recovery of all of the transmission business's costs relating to future transmission investments. To the extent that transmission rentals were needed to fund locational hedging instruments, the transmission business could become entitled to the proceeds of the sales of those instruments. On average, over time, the proceeds from the sale of locational hedging instruments should approximate actual transmission rentals. If locational hedging instruments were allocated to participants 'for free', the equivalent sum would need to be recovered from customers or the government in some least-distortionary manner.

5.4.6 However, the costs of existing transmission assets may not be fully recovered through transmission rentals. The outstanding amount of the transmission business's costs could be recovered through a least-distortionary charge, such as a capacity-based 'tax'. Over time, as more transmission investments were made under this new option, the need for this tax would diminish and the transmission business would recover all of its costs from a combination of transmission rentals and augmented nodal price charges.

5.4.7 Another implication of this approach is that transmission charges to different participants at any given location should be different depending on the timing of their consumption or production.

5.4.8 This means that:

- consumers with low load factors and high coincident peak demands and

[24] Except perhaps charges to recover the cost of efficiently scaled transmission investments that could not be recovered through rentals.

- generators with low capacity factors and high coincident peak injections

5.4.9 will be charged more under this approach than consumers or generators with high load or capacity factors, respectively.

5.4.10 The Frontier report also suggested that such charges should be structured in a way that did not distort participant's operational decisions, as this would lead to sub-optimal use of the existing (sunk) transmission network. Therefore, participants in existence at the time of a new transmission investment decision would pay an essentially fixed lump sum charge (or receive a lump sum rebate) based on the extent to which they were likely to benefit (or lose) due to the undersignalling of nodal prices. (section 3.3.1, pp.21-24).

Views of submitters

5.4.11 Most submitters who gave a view on this option agreed that the ANP approach appeared sound in theory. These parties included Meridian, Counties Power, Vector and Rio Tinto. A few parties, including MRP and Transpower, disputed the theoretical efficiency properties of this option. For example, MRP considered that the premise of the ANP approach – to address the deficiencies in nodal process caused by excessive or premature transmission investment – to be fundamentally flawed. ENA also criticised the emphasis of the option on "supposedly 'premature' transmission investments".

5.4.12 Almost all submitters considered that this option would be too complicated to apply in practice and that no further work should be undertaken on its development. For example, apart from disagreeing with the theoretical basis for the option, Transpower suggested that it was not practicable and would require a lot of subjective assessments and would be controversial. Similarly, Northpower argued that ANP was an overly complicated approach that would be understood by very few people. According to Northpower, this would lead to a widespread mistrust of the methodology and negative business outcomes.

5.4.13 Even submitters who supported the theoretical properties of this option contended that it would require considerable effort to implement it. For example, Vector considered that even though ANP may be superior to the status quo in theory, it would be significantly more complex and time-consuming in practice. Counties Power suggested that if the Commission did pursue this option, it should test the consequences of a range of values of unserved energy and apparently irrational behaviour by participants.

5.4.14 MEUG and Vector considered that the ANP approach could be useful in assessing how to incrementally improve upon the status quo.

Commission considerations

Criterion 2 (Theoretical precision)

5.4.15 The Commission, like many submitters to the Commission's stage 1 consultation paper, acknowledges the theoretical and intuitive appeal of the ANP option. The option was developed from a first-principles 'ground up' framework that draws from the economic theory of spot markets. The option is based on the view that full nodal pricing ought to be capable of signalling:

- not only operational decisions by participants (which go to their use of the existing transmission network)
- but also investment decisions by participants (which go to their use of the existing and future transmission network).

5.4.16 However, full nodal pricing will not achieve efficient participant investment decisions if the transmission network is not itself developed efficiently. This may be due to investment being driven by non-economically-based reliability standards or over-caution by network planners.

5.4.17 The Commission notes that – as discussed in section 2.2 above – a question remains over the need for augmenting nodal price signals where transmission investment is efficient, but reflects economies of scale.

5.4.18 However, putting this issue to one side, the ANP option appears to be a theoretically precise approach.

Criterion 3 (Locational hedging instruments)

5.4.19 The ANP option is designed to work as a complement to full nodal pricing in the energy market. It could also complement various options for locational hedging instruments. However, any locational hedging option that involved providing participants with a 'free' allocation of locational hedging instruments would dampen or offset nodal pricing signals. This would upset the balance of complementary locational signals between nodal pricing and ANP and would require the charges under an ANP option to be exaggerated similar to the way that the slope of TPS charges would need to be increased if locational hedging instruments muted the impact of nodal price signals.

Criterion 4 (Network topology)

5.4.20 ANP could theoretically work with any network topology so long as it was possible to make reasonably reliable predictions about the future likely beneficiaries of any given transmission investment. This point is discussed further below.

Criterion 5 (Implementation difficulty and information requirements)

5.4.21 As noted in the Frontier report, the information and implementation issues for the ANP option are likely to be considerable, a point that was strongly echoed in submissions to the Commission's stage 1 consultation paper. This option requires detailed information about each transmission investment – in particular, the extent to which (if at all) each investment exceeds its optimal capacity or precedes its optimal timing. This information can be used to model the extent to which various participants benefit or lose from the over-investment, noting that any such modelling would involve a degree of speculation. Having said that, all of the locational pricing options except the historical load-flow analysis model involve a degree of speculation as to future participants' behaviour and network flows.

5.4.22 Further, the Commission recognises that the ANP option has not been implemented elsewhere, so there would be no experience to guide its development in New Zealand.

Criterion 6 (Governance)

5.4.23 The ANP option is designed to apply to both loads and generators throughout New Zealand. As all participants would be subject to charges or eligible for rebates, they should all (at least in theory) have a strong financial interest in the assessment of individual transmission investments.

Criterion 7 (Good regulatory practice)

5.4.24 As with all the locational pricing options, the ANP option involves a degree of subjectivity and arbitrariness. These issues arise particularly in relation to this option because it involves a comparison between an actual transmission investment and the hypothetical 'optimal' capacity and timing of that investment. Identifying the optimal transmission investment in a given circumstance ideally needs to be determined with as much care as the analysis used to determine the actual timing of transmission investment. This is unlikely to occur in practice, thus potentially compromising the integrity of the prices produced by this option. The Commission considers however that there may be analytical approaches that could resolve this issue and removes the need for individual technical assessment of each network element.

5.4.25 In addition, as noted above, this option requires modelling to determine the extent to which various participants gain or lose from inefficient over-investment in transmission. Modelling the beneficiaries of a transmission investment is likely to be controversial. This is because benefits and harms to individual participants would be largely a function of future changes in spot prices and dispatch patterns, which in turn would be both be influenced by generator bidding behaviour and patterns of new participant investment. Having said that, reasonably robust techniques are available to assist in this process. For example, future plant development models are widely used to forecast new generation investment timing and location. Further, some market dispatch models now utilise Cournot-Nash bidding assumptions to project spot market outcomes in the presence of market power. Nevertheless, charges under this option are likely to be highly sensitive to the assumptions used in modelling and the choice of those assumptions will ultimately involve a degree of subjectivity.

Criterion 8 (Stakeholder acceptability)

5.4.26 As noted above, submitters were almost unanimously opposed to further development of this option, mainly on account of its perceived complexity. However, as this option is relatively novel, it is not clear that participants would find this option unacceptable if it actually were further developed and implemented. It is also worth noting that many other transmission pricing options are complicated to apply in principle, even if they are simpler in concept.

5.5 Load-flow approaches

Outline

5.5.1 As noted in the Frontier report, load flow approaches involve a process of attributing network costs to participant connection points based on an engineering estimation of the network assets ‘used’ to convey electricity from points of injection to points of withdrawals. Load flow analysis is a well-accepted and understood approach to simulating power flows and network loading under various system operating conditions.

5.5.2 Load flow approaches can be based on the topology of existing network asset costs, as in the Australian market, or on forward-looking network development costs, as in the Great Britain market.

5.5.3 Under the Australian CRNP approach, a cost is assigned to each series element of the network (essentially to each transmission line, transformer and series reactor). This assignment is based on allocating a share of the transmission business’s regulated revenue to individual elements based on the ratio of the optimised replacement cost (**ORC**) of the network element to the ORC of all network elements used to provide prescribed use of system services. The usage made of each element by the load at each connection point is then determined through several steps, drawing from a range of actual operating conditions from the previous financial year. The range of operating scenarios is chosen so as to include the conditions that result in most stress on the transmission network and for which network investment may be contemplated. Finally, the individual network element costs are allocated to loads based on the relative utilisation of each element by each load over the range of operating conditions considered. A fuller description of the methodology was provided in the Frontier report.

5.5.4 Under the British ICRP, National Grid utilises a DC load flow transport model to calculate the marginal costs of investment in the transmission system required as a consequence of an increase in demand or generation at each connection point. Unlike the CRNP approach, the ICRP methodology is based on the forward-looking costs of network development at various locations. This calculation is based on a study of peak conditions on the transmission system. Further details are provided in the Frontier report.

5.5.5 In both jurisdictions, only a portion of shared regulated network revenues is recovered through charges imposed on the basis of load flow analysis. The remainder is generally recovered through postage-stamped charges.

5.5.6 Importantly, in a nodal market design such as New Zealand (albeit not a 'full' nodal market), it would be necessary to deduct from the estimated LRMC of the transmission network at each location the forecast average SRMC of the network (ie forecast spot price differentials) at those locations in order to avoid double-counting locational signals provided in the wholesale spot market. Therefore, the load flow-based pricing signals would comprise only those signals not provided through the spot market. This deduction is not required in Britain or Australia because of the lack of locational marginal pricing of electricity (in Australia's case, within the regions across which transmission charges are determined by jurisdictional transmission businesses). As explained in section 4.3 above, a similar deduction is required for the TPS methodology. The key difference between the ICRP approach and the NERA TPS option is the degree of precision in setting the LRMC-based charges: The NERA 'straw man' approach is based on a very approximate estimate of the north-south pattern of LRMCs of transmission through the network whereas the ICRP approach is intended to be far more precise.

Views of submitters

5.5.7 Of the submitters that gave an opinion on the load-flow analysis options, nine stated that load-flow modelling was not – or unlikely to be – an appropriate basis for cost allocation. Most of these held strong views against the use of these options and several referenced previous experience of these methods in New Zealand. These submitters made the following comments.

- The option was complex, contentious and potentially unstable – both because of changes in load flows and because of arguments about the methodology (Counties Power, Genesis, MEUG, Rio Tinto, WPI, Transpower).
- This approach had been tried previously and passed over (Orion).
- These approaches introduce complexities over what benchmark time and characteristics the load-flow should be based on (Powerco).
- It may be a technically accurate way of measuring ex-post use of the grid, but it is not a good way of signalling ex-ante future costs of generation and transmission decisions, particularly in a hydrology dominated system (Meridian).

5.5.8 Those submitters – four in total – who appeared to believe these options may be worth further investigation as an appropriate basis for cost allocation made the following comments.

- Load flow modelling could be part of developing an LRMC of the grid to reflect each point of injection (Northpower)
- Review of the forward-looking load flow methodology should help to ensure the locational pricing methodology the Electricity Commission decides to implement is the most robust one, and may inform work on a TPS approach (MRP).
- Cost-reflective load-flow analysis could be used to set the tilt for TPS of forward looking load-flow analysis could be used as a basis for valuing the contribution from transmission alternatives (Todd Energy).

5.5.9 Transpower noted in its submission that it did not favour load flow based approaches except possibly for relatively simple situations involving two or three grid users only. Load flow based allocation methods rely on assumptions and in significantly interconnected parts of the grid these assumptions may bear little relationship to the beneficiary-pays principle in practice.

5.5.10 For example, Manapouri clearly benefits from transmission out of Southland, the HVDC and transmission in the North Island due to the impact on nodal prices, yet a loadflow approach would only allocate assets in Southland to Manapouri as on average network power flows in and out of Southland are minimal.

5.5.11 All submitters who gave a view – whether they supported the investigation of the load-flow analysis or not – favoured the forward-looking ICRP methodology over the historical CRNP methodology.

Commission consideration

Criterion 2 (Theoretical precision)

5.5.12 As noted above, load flow approaches can be based on existing network asset costs or on forward-looking network development costs.

5.5.13 The forward looking load-flow approaches involve the allocation of costs in a manner that seeks to signal the LRMC of the transmission network at a given location. In a nodal market design, this requires adjustment for the SRMC signals already forecast to be provided through the spot market. So long as this is done and LRMCs are calculated on the basis of forward-looking network costs (as in Britain), the theoretical precision of this forward-looking option should be somewhat comparable to the ANP option. However, this is easier said than done, with load flow analysis less appropriate for estimating LRMCs at locations on the main shared grid than in relation to connection assets.

5.5.14 The approaches based on existing network asset costs and load flows do not directly signal LRMCs, but provide a signal to customers that they will pay for future investments in the same manner as they pay for existing assets. This should influence participant behaviour accordingly and provide theoretically precise signals. The key issues are that this will involve a lag in the signal and that participants will need to have access to transmission forecasts (either their own or others such as Transpower).

Criterion 3 (Locational hedging instruments)

5.5.15 Load flow pricing approaches could complement a range of locational hedging instrument designs. To the extent that a particular hedging option led to a dampening or offsetting of nodal pricing signals to consumers, this would obviate the need to deduct the forecast SRMC signals from the LRMC-based prices that would be calculated under this option.

Criterion 4 (Network topology)

5.5.16 As briefly discussed in the Frontier report, load flow-based pricing approaches are best suited to meshed networks where utilisation levels are relatively constant. The risk with radial networks experiencing ‘lumpy’ augmentation costs is that load flow-based charges could rise immediately following investment and fall as utilisation rises. However, this will depend on the precise approach adopted and could be avoided with suitable adjustments to the methodology. For example, as discussed in the Frontier report, the Australian CRNP approach adjusts pure CRNP-based cost allocations with a utilisation scaling factor in some jurisdictions.

5.5.17 Similarly, depending on how forward-looking load flow cost allocation is undertaken, it should be possible to smooth out the impact of the lumpiness of augmentations on load-flow-based charges. This could be done by setting charges based on the incremental financing costs of bringing forward new transmission investment at a particular location rather than imposing charges reflecting the entire costs of new augmentation due to increased demand at a particular location.

Criterion 5 (Implementation difficulty and information requirements)

5.5.18 Load flow-based approaches based on the costs of existing network assets (such as CRNP in Australia) are likely to be simpler to apply and more stable than approaches that seek to use forward-looking costs (such as ICRP used by National Grid in Britain). This point is also relevant to the good regulatory practice criterion (see below). Nevertheless, unlike some other options, load flow-based approaches have a history of use in New Zealand and elsewhere.

5.5.19 One option is to only use load-flow analysis to delineate connection assets from interconnection assets instead of the present technical approach to delineating between these assets that is based on network topology. For example, all assets with customer utilisations above a threshold could be allocated as connection assets to generation and load. Revenue requirements for remaining assets could be allocated using some other method.

Criterion 6 (Governance)

5.5.20 Depending on how load flow charges are applied – in particular, whether charges are imposed on both load and generation or just one side of the market – they could give most or all participants in the market a financial interest in the costs of transmission augmentations.

Criterion 7 (Good regulatory practice)

5.5.21 As noted in the Frontier report, the load flow cost allocation process can be something of a ‘black box’ from an outsider’s perspective. It is particularly difficult to combine load flow allocation methods with forward-looking cost estimated to arrive at reliable LRMC figures. However, the approach is replicable with the aid of suitable models and assumptions.

Criterion 8 (Stakeholder acceptability)

5.5.22 Many submitters considered the load flow option was complex, contentious and potentially unstable based on previous New Zealand experience. Therefore, it is likely that many stakeholders would find the approach in its pure form unacceptable. The submitters that did not reject load flow modelling outright considered that it could inform the setting of LRMC to help set charges under other options, such as TPS pricing.

5.6 NERA TPS options

Outline

5.6.1 NERA's proposed versions of a TPS charging methodology were discussed in section 4.3 above. Key features of NERA's proposed approach are that:

- It would focus on providing LRMC-based locational signals to generators, rather than loads, on the basis that:
  - Existing RCPD-based charging arrangements already provide existing loads with appropriate incentives to curb demand at peak times;
  - New generators are likely to be more responsive to locational transmission signals than new loads.
- In setting LRMC charges to generators, the current HVDC charge would be abolished and subsumed into the general LRMC charge.
- Whether a relatively simple latitude-based north-south tilt (known as the 'straw man' TPS option) was adopted or a more localised 'bespoke' approach or indeed any locational variation at all would depend on whether and how likely future flows on the network could be characterised and how such flows would affect future LRMCs. This could be informed by the Commission's SOO or replacement document containing forward looking scenario analysis.
- The degree of tilt in the charge would not be revisited regularly, in order to promote predictability of the charge.

Stakeholder views

5.6.2 While the NERA TPS proposal was developed under the auspices of the CEO Forum, it has not been publicised for formal stakeholder feedback.

5.6.3 As noted in section 4.3 above, one of NZIER's reports on behalf of MEUG and included as part of its submission heavily criticised NERA's proposed options. However, NZIER focussed most of its criticism on other aspects of NERA's proposals – namely, the abolition of the HVDC charge and a move to shallower connection charging – rather than the TPS options. NZIER disagreed with the abolition of the HVDC charge on the basis that this would further reduce the locational signals applying in the market. NZIER considered that even the present HVDC charge substantially under-signalled the LRMC of the link (p.13), and the beneficiaries of the link could quite clearly be identified as South Island generators and North Island loads (pp.13-14). NZIER went on to comment that the HVDC charge does not create an asymmetry of incentives to invest in South Island capacity between incumbent and new generators (pp.15-16).

Commission consideration

5.6.4 NERA's TPS option(s) provide a useful supplement to the high-level options outlined in the Commission's stage 1 consultation paper.

Criterion 2 (Theoretical precision)

5.6.5 As with Grant Read's TPS option, the NERA TPS options are unlikely to offer the most theoretical precision of all the high-level options. The NERA "straw man" TPS is based on a stylised grid topology in which it is assumed that:

- the average direction of flows is south to north and therefore
- the principal purpose of the 'main trunk' of the transmission network is to provide a 'highway' to facilitate such south to north flows.

5.6.6 According to NERA, the degree of tilt would be applied on the basis of the connection points/zones on the south-to-north latitude of this simplified network topology diagram (or some other simple representation), rather than simply on the basis of the physical latitude of connection points on a map of New Zealand. (p.73).

5.6.7 Only if it were possible to identify certain areas where the direction of power flows was reasonably clear should the bespoke TPS option be used.

5.6.8 If no enduring structural characterisation of network flows could be made, then the transmission pricing methodology should revert to an 'efficient tax'.

5.6.9 The NERA proposals therefore allow the TPS option to be tailored to provide the most suitable practical proxy for the underlying LRMC of the transmission network. However, any TPS methodology will tend to remain a generalised proxy for the signals missing from nodal prices rather than a precise estimate of those signals. This would not resolve the present lack of generation investment in areas such as the north and west coast of the South Island.

Criterion 3 (Locational hedging instruments)

5.6.10 As noted above, depending on the precise form it took, the TPS option could be compatible with a number of different styles of locational hedging instrument. If the TPS reflected a gradual linear tilt from south to north, it could partly (albeit crudely) compensate for any loss of nodal price signals to loads due to the adoption of the LRA or hybrid approach. This would require the slope of the tilt to be exaggerated beyond what it would be if there was no loss of nodal pricing signals.

5.6.11 A bespoke option could, at least in theory, be tailored to offset any muting of nodal pricing signals due to the introduction of location hedging instruments.

Criterion 4 (Network topology)

5.6.12 As noted above and in the NERA report, the suitability of a gradually TPS approach to New Zealand is intimately tied to the broadly linear nature of the transmission network and the characterisation of the role of the network as facilitating the transfer of power from south to north. If network flows were anticipated to change or become more volatile, an enduring characterisation may not be possible and a TPS methodology may not be appropriate.

Criterion 5 (Implementation difficulty and information requirements)

5.6.13 As with the Read TPS, NERA's TPS options would require some effort to implement. The extent of this effort would depend on the sophistication of the methodology, which in turn would depend on the outcomes of the analysis used to predict the future 'structural' direction of power flows in the system. This analysis could be informed by the Commission's SOO, but NERA itself was not prepared to come to firm conclusions in this regard.

5.6.14 In general, there would be a trade-off between information and implementation difficulty on the one hand and theoretical precision and ability to compensate for any muting of nodal pricing signals due to locational hedging instruments on the other hand.

Criterion 6 (Governance)

5.6.15 NERA's TPS option was focussed on application to generators. But given that an interconnection charge would continue to apply to loads, it should give both loads and generators financial incentives to scrutinise transmission investment decisions.

Criterion 7 (Good regulatory practice)

5.6.16 The Frontier report noted that Read's TPS approaches involve a degree of subjectivity and arbitrariness in setting the slope of the tilt. The NERA TPS options are likely to raise similar issues because the determination of the LRMCs of injections at different locations on the transmission system (even in a bespoke manner) is likely to be complicated and difficult to undertake completely transparently.

Criterion 8 (Stakeholder acceptability)

5.6.17 As noted above, it appears that some form of TPS option would command broad support from stakeholders. The NERA TPS options may be more acceptable than the Read options because NERA's charge focuses on generators, ensuring that both sides of the market pay a share of transmission costs.

5.6.18 However, the proposed abolition of the HVDC charge would be opposed by some stakeholders, and the NZIER report suggests that MEUG would be one such opponent. In particular, the Commission notes that the costs of the HVDC upgrade are substantial and would have a significant impact on retail prices if recovered through the interconnection charge.

5.7 NZIER option 'packages'

Outline

5.7.1 As discussed in section 4.3 above, NZIER proposed a range of option 'packages' in their reports for MEUG. Specifically, NZIER proposed the following packages be considered:

- Option D – replaced the existing HVDC charge with the capacity rights approach and imposed additional charges based on a but-for approach for new generators and material new loads.
- Option E – replaced the existing HVDC charge with the arbitrageur approach and imposed additional charges based on a but-for approach for new generators and material new loads.

5.7.2 Under the 'but-for' charging approach, Transpower would seek long term contracts with new generators and major new loads to underwrite the costs of significant economic and reliability-driven transmission investments. The criteria for applying the approach should be whether it was possible to identify the beneficiaries of the investment at reasonable cost. As in PJM, connecting parties would receive FTRs in exchange for contributing towards the funding of an upgrade. Connecting parties would only be required to fund the cost of the additional capacity they require, even if the transmission operator chooses to build a larger asset to take advantage of economies of scale.

Stakeholder views

5.7.3 Stakeholders have not yet had a formal opportunity to express their views on the NZIER proposals to the Commission. However, the stage 1 consultation paper did seek views more generally on the but-for approach to charging for transmission investment.

5.7.4 Some submitters (Northpower, Contact) supported the concept of a but-for approach, but were concerned about the difficulty of applying it in practice. WPI suggested a but-for approach should not be used retrospectively, but could be used in a forward-looking manner in relation to future investments.

5.7.5 More specifically, submitters had the following concerns about this approach:

- Complexities would probably result in stalling any action which is critical to get the appropriate signals for investment now (Northpower).
- The problem of free-riding; participants that benefit from an interconnection investment, but are not deemed to have caused it can free ride (Vector, Transpower).
- A but-for approach does not take into account the benefits that accrue to other users of the grid and so may overstate the costs attributable to the generation plant (Transpower).
- It could deter new generation investment where it is most needed and encourage a higher-level of embedded generation – which may be of suboptimal size (Contact).
- Difficult to enforce fairly given the organic growth in types of generation and for combinations of load and generation (Contact).
- The deeper the connection pricing methodology goes the greyer and more contentious the analysis of causation becomes (Meridian).
- In many cases the need for transmission investment is driven principally by organic growth, but this fact may be masked by a final single connection that appears to cause the need for the augmentation (Transpower).
- Although the method is relatively uncontroversial in PJM, this may be because the costs at stake are generally small relative to total project costs and the overall value of the PJM grid. In NZ our investments are relatively lumpy (Transpower).
- Relative investment lead times may also be an issue. Transmission investment lead times are so long that Transpower may need to commit to

grid augmentations before new generation plants are constructed. (Transpower).

Commission considerations

But-for charging approach

5.7.6 As highlighted in the Frontier report, a number of difficulties surround the application of the but-for charging approach in the context of the New Zealand market. The chief difficulty is working out which connecting parties ‘cause’ an investment to occur or be advanced in a regulatory design in which transmission investment does not necessarily follow the arrival of a new generator or the emergence of network constraints. As noted by Transpower, the need for transmission investment may be driven by organic load growth rather than a discrete new connection. Alternatively, a discrete new connection may not lead to investment in the grid at all if such grid investment cannot be justified under the GIT.

5.7.7 As noted in the Frontier report, the presence of capacity market arrangements in northeast United States markets means that generators need to ensure they can be dispatched to meet peak load. This supports the case for a but-for approach to transmission charging (and investment), compared to the energy-only New Zealand market where generators are not separately paid to provide capacity. The information provided by NZIER did not explain how these difficulties could be resolved.

5.7.8 Nevertheless, even in the United States, application of the but-for approach has not been without controversy. A report by Castalia Strategic Advisors prepared for Transpower in 2007 and provided by Transpower to the TPTG highlighted the subjectivity of the but-for approach in operation in the United States. In particular, the Castalia report commented that there has been substantial controversy in PJM over the method used to determine benefits and allocate costs.

5.7.9 The Commission considered the but-for approach as part of the consultation on the proposed transmission pricing methodology in 2007[25]. At the time, the Commission considered that the but-for approach was not practicable to implement at the time for the following reasons:

(a) It is difficult in practice to consistently apply over the entire grid.

[25] Electricity Commission, *Transmission pricing methodology summary of submissions and provisional response paper*, 11 April 2007.

(b) It relies on defining a baseline grid[16] against which the impact of new investments can be assessed. Defining the baseline grid is naturally contentious.

(c) Selection of the demand forecasts to define the baseline grid is difficult.

(d) Extending the method to existing assets involves a large number of subjective decisions. For example, it is difficult to objectively assess issues such as which load came first or to derive some unique allocation of assets, particularly where loop flows may exist. As a result, a workable definition may not be possible.

(e) Defining the benefits attributable to the new asset (being connected) to be netted off the “but for” charges is problematic.

(f) Transaction costs would be high.

(g) It is not particularly transparent.

(h) The “but for” method is not as widely accepted as those submitters promoting it appear to contend and it is currently being re-evaluated in the PJM area. This re-evaluation stems largely from the difficulty in dealing with the above practical implementation issues.

5.7.10 **Commission’s position -** At this stage, the Commission considers that the above reasons remain valid and does not consider that a but-for approach to transmission charging is worth further analysis.

HVDC charge replacements

5.7.11 The Commission has investigated both the alternatives to the current HVDC charge proposed by NZIER. The capacity rights approach involves auctioning (physical) rights for generators to be dispatched to the extent that dispatch (or increased dispatch) relies on flows on the HVDC link. The arbitrageur approach involves allowing the owner of the link to trade its capacity by purchasing power in one island and selling it in the other.

5.7.12 In order to pursue these options further the Commission would need to be convinced that the costs (including increased complexity and transaction costs) would be outweighed by the benefits (including increased operational and investment efficiency).

5.7.13 The Commission notes that the capacity rights approach could produce inefficient dispatch. This could occur in circumstances where least-cost dispatch required the full HVDC capacity to be utilised to transport power between the islands but participants did not offer high enough prices to acquire all the HVDC rights. The market would experience a 'deadweight loss' because HVDC capacity that could potentially be used to transport power from a region where electricity had a relatively low value to a region where electricity had a relatively high value would be prevented from doing so. However, this inefficiency may not be substantial for similar reasons to those given in considering the potential inefficiencies of per-MWh charging (Appendix 4).

5.7.14 The arbitrageur approach to the HVDC may also give rise to the risk of inefficient dispatch, given that it could involve the arbitrageur withholding a proportion of (sunk) link capacity to maximise its profits. Even if this were not the case, it is difficult to see what purpose this proposal achieves other than a wealth transfer from North Island loads (who currently do not contribute to HVDC costs) to South Island generators (who pay the HVDC charge). Having said that, the Commission could consider privately-driven upgrades to the HVDC link in the future. However, such investments have generally not been commercially successful in the Australian market.[26]

5.7.15 The question of whether the two options could lead to more efficient investment in HVDC assets is of limited relevance as it is not expected that a second HVDC link will be required. It is hard to construct a scenario in which the benefits of a second link justify the very substantial costs of such as investment. (This issue is further considered in the stage 2 consultation paper, section 3.3 which deals with the analysis of potential benefits from locational signalling.)

5.7.16 In addition, the capacity rights approach fails to recognise that a generator does not need to export power over the link in order to benefit from flows across the line. For example, a low-cost South Island generator that was always fully dispatched could still benefit from the HVDC link if demand through the link for South Island exports increased nodal prices in the South Island. Yet under the capacity rights approach, such a generator would not be required to acquire or pay for any rights.

5.7.17 The Commission acknowledges that if HVDC costs are not recovered in the ways suggested by NZIER, they will need to be recovered in some other way that could also distort efficient decisions or prevent the achievement of dynamic efficiency. In this context, the Commission is considering locational hedging options alongside the TPM in which FTRs on the HVDC link would be auctioned to participants and the proceeds used to help recover HVDC costs

5.7.18 **Commission's position -** For the reasons above, the Commission does not at this stage intend to further pursue either of the HVDC options proposed by NZIER, both of which would involve increased complexity and transaction costs.

[26] The Murraylink and Directlink DC interconnectors have 'converted' to regulated status shortly after commencing operation. The Basslink DC interconnector continues to operate as an unregulated interconnector.

6. Further issues

6.1 Introduction

6.1.1 This section deals with issues concerning connection charges, the treatment of transmission alternatives, service quality and pricing, and static reactive power compensation. To a large extent, these issues are independent of the broad form of the TPM and as such have been discussed separately.

6.2 Connection charges

Outline

6.2.1 The Commission's stage 1 consultation paper briefly discussed issues surrounding 'dedicated' connection assets in the context of earlier concerns expressed by NERA in their discussion paper for the CEO's Working Group (pp.29-30). The Commission considered that in light of the contestable market for connection assets in New Zealand, parties faced the correct incentives to negotiate the development of new connection assets and, as a result, the existing regulatory regime appeared satisfactory. However, the Commission did not consider the incentives surrounding new participant investment in relation to existing connection assets in the stage 1 consultation paper.

NERA report

6.2.2 As noted above, the NERA report discussed issues arising from the definition and application of shallow connection charges in the existing TPM. In particular, the NERA report expressed concern that the current treatment:

- distorted new generators' locational incentives – in particular, by providing artificial incentives for generators to:
  - locate directly on the interconnected network to avoid paying a share of charges in respect of existing connection assets; and
  - embed in the distribution network to avoid paying a share of connection charges while being entitled to receive 'avoided transmission charge' payments from lines companies; and
- raised disincentives on 'first-movers' to invest in new large extension assets and potential market power or free-rider problems if they do.

6.2.3 In response, NERA suggested moving to a 'shallower' definition of connection charges so that investors' locational decisions would not be distorted by the obligation to pay deep connection costs in some locations and not others. In the absence of such a shift, NERA raised the prospect of modifying the existing approach to promote competitive neutrality for embedded generation, revising the arrangements for privately funded and owned new extension connection assets and expanding the scope of application of the GIT to such assets.

6.1.3 Views of submitters

6.2.4 Submitters raised a number of both general and specific concerns about the existing connection arrangements. Many of these concerns were similar to those raised in the NERA report.

6.2.5 At a general level, Meridian, Orion and Transpower suggested that the current definition of ‘connection’ and ‘interconnection’ assets could distort the locational incentives of new loads and/or generators. In particular, Meridian considered that the current regime created incentives for generators to avoid connection charges associated with existing connection assets, to build smaller plants and to avoid building near existing remote loads. Further, the current arrangements for shared connection assets charging could lead to volatility as customers connected or disconnected from the transmission network. These were the same concerns as those raised in the NERA report.

6.2.6 In relation to new connection assets, while Contact considered that parties could build their own ‘spur’ assets under the current arrangements, this ought to be a consultative process to avoid the building of sub-optimal capacity lines. Transpower also highlighted the scope for potential sub-optimal investment in new connection assets where the most economic investment from a national perspective could be something different from that chosen by a first mover in a ‘greenfields’ location. In these circumstances, Transpower suggested that ‘back stop’ provisions should allow for the regulated recovery of right-sized investment. Similarly, EECA expressed concern about the arrangements for the development of ‘shared’ connection assets to be utilised by new remote renewable plant. Genesis suggested that mechanisms for the allocation of capacity rights for non-regulated investors in transmission assets could be considered.

6.2.7 At a more specific level:

- Northpower raised concerns about the application of the connection/interconnection classification to ‘looping spurs’.
- Orion questioned the allocation of land and buildings costs between connection and interconnection charges, Transpower’s use of allocation factors and the pricing implications of replacement assets.

Commission considerations

New connection assets

6.2.8 As noted above, in the stage 1 consultation paper, the Commission considered that in light of the contestable market for connection assets in New Zealand, parties faced the correct incentives to negotiate the development of new connection assets. As connection assets typically serve a relatively small number of parties, it ought to be generally the case that the actual or potential beneficiaries of connection assets can come to a mutually beneficial arrangement to determine the appropriate size, capacity and timing of connection assets as well as their funding. The transactions costs of negotiation between a small number of parties should not be insurmountable.

6.2.9 The question is whether such negotiation is likely to yield efficient outcomes where connection assets increase in size and scope. NERA raised the prospect of deep connection ‘extension’ assets giving rise to inefficiency problems because potential ‘first movers’ would be deterred from investing if they know other parties might try to negotiate access when the first mover has sunk its investment and is in a weak bargaining position. On the other hand, if the first mover did choose to invest on its own, NERA expressed concern that the first mover would be able to deny access to later parties. NERA’s solution was to allow the GIT to be applied to such investments and the costs recovered through regulated charges (pp.53-54). Transpower expressed similar views.

6.2.10 While the application of the GIT to extension assets would avoid protracted negotiations and hold-out problems, the Commission notes that the scope for first mover and free rider problems under the present arrangements may not be significant in practice. If there are several parties who have an interest in a new extension asset, they have every incentive to form a consortium to not only fund such an investment, but to ensure it is ‘right-sized’ to meet all their future needs at least cost. This is because it would be in the interest of any potential first mover to share the costs of extension assets if those assets reflected economies of scale (eg if it were cheaper to build one 150 MW line instead of three 50 MW lines as in NERA’s example). Similarly, it would be in the interests of any potential ‘second mover’ to be involved in a consortium to ensure certainty over its ability and the price to connect to such extension assets.

6.2.11 Even if a consortium cannot be formed before an extension asset is built, both the first-moving investor and a later connecting party have an interest in negotiating an arrangement to enable the later connection to proceed. In this respect, economic efficiency does not require the investor to agree to allow a second party to connect to its extension asset at only incremental cost. So long as the second party stands to benefit from connecting to the investor’s extension asset, it is perfectly reasonable for the original investor to seek a contribution by the later connecting party to the investor's initial outlay. However, if the investor seeks too high a contribution, the second party may choose not to connect and the investor is no better off. It is only in the rare cases where the investor has more to gain by preventing the second party from connecting than from receiving a contribution to its sunk costs that a negotiation would not be successful.

6.2.12 A failure to negotiate a connection to sunk extension assets could reflect either of the following:

- the extension asset is only large enough to meet the investor's own genuine needs for export capacity to the interconnected network; or
- the investor has market power and would rather appropriate the rents accruing from its location than receive a contribution to its sunk costs.

6.2.13 Both of these situations are unlikely for different reasons.

6.2.14 First, as noted above, if economies of scale are available in the development of extension assets, the investor would have had an incentive to either form a coalition before investing or invest in an asset that was 'over-sized' for its own needs from the outset. If the investor did not consider that other parties were likely to emerge to utilise any spare capacity it developed, it is unlikely that a GIT analysis would have found it worthwhile to over-size the asset.

6.2.15 Second, it is difficult to see how an investor constructing a new extension asset would be in a position of local market power. Presumably, the investor's generator would be in a location without much (if any) local load. Therefore, denying access to the extension asset would be unlikely to maintain or boost its nodal price compared to a situation where the second party simply chose to build a generator closer to the load.

6.2.16 It is only if an investor built an extension asset to a source of extremely cheap power that it may be incentivised to deny access to subsequent generators. But this again raises the question of why a consortium to develop a right-sized line to share the costs would not have been formed at the outset if it was profitable for them to invest individually.

6.2.17 Alternatively, if the first mover requested Transpower to build the extension asset so that it became open access, subsequent entrants would pay connection charges based on their relative AMIs. This would likely approximate the result that would be achieved by ex ante bargaining, although the Commission is open to submissions reflecting contrary views.[27]

[27] NERA poses the question of whether subsequent connecting parties should be required to compensate the first-moving investor for "the time spent solely financing what is not a shared connection asset" (p.29). The Commission notes that the first mover would have had the benefit of being the sole user of the asset prior to

6.2.18 **Commission's position**: At a minimum, the Commission would require stronger evidence of real-world cases where potentially mutually beneficial access arrangements for extension assets failed to occur because of bargaining problems before considering extending the scope of investments to which the GIT can be applied.

Existing connection assets

6.2.19 The Commission agrees with NERA that the charging regime for existing connection assets may lead to inefficient by-pass of sunk transmission assets. For example, a new generator may choose to locate at interconnection assets or embed within the distribution network to avoid paying charges in relation to existing connection assets. This problem arises because of how the TPM charges for connection assets but may also arise for other methods of charging.

6.2.20 **Commission's position** - The Commission considers this issue is worthy of more detailed consideration and consultation.

6.3 Transmission alternatives

Outline

6.3.1 In the stage 1 consultation paper, the Commission said that it was considering the treatment of transmission alternatives as part of the review, promoted by efficiency concerns and that fact that to date there have been no transmission alternatives approved as alternatives to new interconnection assets.

Views of submitters

6.3.2 Submitters' views were split on this issue, with generators (apart from Todd Energy) and Transpower largely supporting existing arrangements and lines companies and large users supporting a change to the treatment of transmission alternatives.

6.3.3 WPI commented that a key question was whether there is a policy desire to tilt the playing field in a way that brings forward transmission alternatives and develop transmission alternative markets in advance of whether they might otherwise become established. In WPI's view this is a policy-level issue that could stand on its own as a market development initiative.

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the arrival of the later parties. This is presumably consistent with what the parties would have negotiated *ex ante* if they had similar bargaining power.

6.3.4 Reasons given in support of the existing arrangements were:

- Generation transmission alternatives are not a complete substitute for transmission – they are not 99.9% reliable – nor do they offer the two way diversity of transmission (Meridian).
- The current approach ensures a level of rigour is applied to any transmission alternative proposal (Meridian).
- Regulation of transmission alternatives creates risks that generation projects that would have gone ahead anyway would end up being subsidised (MRP).
- Only Transpower is in a position to certify that the provision of transmission alternative services is actually needed at any particular time and hence providers of transmission alternatives should not be about to gain access to regulated funding independently of Transpower (Transpower).

6.3.5 The Commission notes that Transpower's comment could create a perception of competing interests, in that Transpower both benefits from receiving regulated funding for its own investments as well as adjudicates other participants' proposals for transmission alternatives.

6.3.6 Genesis commented that weaknesses in the treatment of transmission alternatives to date have more to do with Transpower and the Commission's application of the existing framework rather than the framework itself.

6.3.7 Large users and line companies made the following comments in support of altering existing arrangements:

- Timeframes are presently too short for parties to offer alternatives that are viable but not committed (Northpower).
- Some transmission alternatives (DSM strategies) require long term changes in behaviour and investment that cannot be contracted or guaranteed in the short timeframe required to be transmission alternatives. A long term marginal price signal will provide a better signal to encourage this type of DSM response (Orion).
- There should be a mechanism that provides funding directly to transmission alternatives such as local or distributed generators. Part of the problem with the existing nodal pricing arrangements is that the energy prices received by generators do not reflect the full value that consumers place on supply reliability whereas network investment assessments under the GIT value reliability at a much higher price (Todd Energy). In this context, Grid Support Contract (**GSC**s) are a positive mechanism that should be developed further (Vector).

- Demand response and electricity efficiency can potentially be used as transmission alternatives but these do not receive the same transmission pricing signals as grid connected generation or load. Many consumers have minimal exposure to nodal prices and signals provided by transmission charges (EECA).
- Barriers include lack of consumer information or awareness of opportunities and free rider problems (EECA).
- Distributed generation and demand side management are treated very badly by the existing nodal pricing system and by the pricing counterparty arrangements that effectively give remote generators subsidised access to markets where they compete with those alternatives (ENA).
- The regime in place favours transmission investment over alternatives because of the regulated certainty for approved transmission investments (WPI).
- Transpower only seriously looks into alternatives when it has to and then only as a stop gap (WPI).
- Some transmission alternatives, such as demand side options and small-scale distributed generation, require aggregation in order to be viable (WPI).

6.3.8 Business New Zealand appeared to consider transmission alternatives an important issue saying though, that the issue should be about how it might be possible to take a commercial energy market project and make it a true transmission alternative. However, in Business New Zealand's view, in the face of being unable to progress this issue, the Commission should abandon all consideration of transmission alternatives.

6.3.9 In its report for the CEO Forum, NERA noted that the signals faced by existing generators to embed in the distribution network are in part addressed by the scope of the prudent discount arrangements. However, new generators considering whether to embed do not face competitively neutral signals.

Commission considerations

6.3.10 In the stage 1 consultation paper, the Commission noted that transmission alternatives should generally face similar transmission pricing signals as grid-connected loads and generators. The Commission commented on the need to review arrangements for embedded generators to ensure competitive neutrality with grid-connected generators.

6.3.11 Many of the reasons given by submitters for changing the treatment of transmission alternatives relate to aspects of the market arrangements other than transmission pricing. In particular, a common complaint amongst submitters favouring change was a lack of time or information for providers of alternatives to properly compete with transmission solutions in GIT assessments. In particular, WPI commented that Transpower was only incentivised to consider transmission options and that the existing arrangements favour transmission investment over alternatives because of the regulated certainty for approved transmission investments. Some submitters reinforced their earlier points about the inadequacies of nodal pricing for rewarding demand-side or distributed generation options.

6.3.12 Submitters that appear in support of the existing arrangements stated that transmission alternatives offered neither the same level of reliability or diversity that transmission solutions offer, and that regulation of transmission alternatives may lead to projects that would have gone ahead anyway being subsidised.

6.3.13 The Commission notes the evidence to date that there have been no specific transmission alternatives approved as alternatives to interconnection assets since the Part F regime came into effect in 2005. There have been a significant number of transmission approvals made during this time, including large investments such as NAaN and NIGU.

6.3.14 The Commission also notes the difficulty in contracting with generation plant that might have gone ahead regardless of transmission alternative funding and the difficulty of establishing the correct level of funding for transmission alternatives that also receive market revenues. For this reason, the Commission's preference is for market signals as part of a TPM rather than centralised funding arrangements made by Transpower and approved by the the regulator for cost recovery from transmission counterparties.

6.3.15 The view that transmission alternatives do not offer the same reliability as transmission assets is based on a deterministic view of grid reliability which focuses on the performance of individual elements. This is incorrect as the reliability of supply to a specific location is determined by the interplay of load and generation performance as well as the components of the transmission system. The overall difference in reliability between transmission solutions and transmission alternatives can be evaluated using well established probabilistic techniques. Using the value of unserved energy this then allows comparison of the economic performance of various transmission and non-transmission solutions. Often the analysis shows the difference in reliability is immaterial.

6.3.16 In some cases, particularly the large transmission investments, no single transmission alternative would suffice and there needs to be a mechanism to achieve the benefits of aggregation. The absence of approved transmission alternatives and the limited number of proposals may suggest it is worth considering arrangements that might encourage aggregation.

6.3.17 The Commission notes that Transpower's Upper South Island demand side participation trial successfully demonstrated the opportunity to use demand participation through the use of aggregation techniques.

6.3.18 **Commission's position** – The Stage 2 consultation paper, section 4.2, includes an option for improving the transmission alternatives regime, but this will need to be pursued by the Commerce Commission.

6.4 Service quality and pricing

Outline

6.4.1 As part of the first stage of the review, the Commission considered issues with the current transmission pricing approach. The TPTG assisted in the identification of issues and some members specifically noted that the transmission prices paid do not directly relate to the service levels they request or receive.

6.4.2 In the stage 1 consultation paper, the Commission considered possible options for linking price and service. The stage 1 consultation paper noted that submitters who raised the issue of linking price and service recognised that Transpower is:

(a) subject to performance incentives in respect of its pricing and service through part 4 of the Commerce Act 1986, and

(b) liable for direct costs (capped) for failing to make available connection assets under the Benchmark Agreement; and similarly, in respect of interconnection assets under the Interconnection in part F of the Rules.

6.4.3 In addition, the stage 1 consultation paper noted that, under the current framework, the TPM is a cost-allocation methodology allocating asset capital charges, asset maintenance and other costs. As an allocation methodology it is not possible for the TPM to link price and service.

6.4.4 The merits of a scheme to link price and service in respect of a failure to provide transmission services were considered during the development of the Benchmark Agreement and Interconnection Rules in May 2007.

6.4.5 At the time, six options were considered:

(a) liability for direct costs;

(b) liability for total costs;

(c) an unconditional service guarantee (**USG**);

(d) suspension of grid charges;

(e) voluntary insurance; and

(f) no liability.

6.4.6 At the time, the Commission's decision was to favour option (a) – liability for direct costs with elements of (d) – suspension of grid charges. However, the Commission advised that it would review the merits of a USG, after the Benchmark Agreement and Interconnection Rules were in force[28].

The stage 1 consultation paper

6.4.7 The stage 1 consultation paper discussed a USG and voluntary insurance, being the two mechanisms that may incentivise efficient decision making by Transpower, transmission customers (load and generation connections) and end-users in respect of price/service trade-offs. The Commission's current description of how these mechanisms might work is set out below.

An Unconditional Service Guarantee (USG)

6.4.8 A USG would require Transpower to pay compensation to connected customers in the event of an unplanned loss of supply arising from the failure of transmission assets.

6.4.9 Compensation could be set based on a value of lost load[29] multiplied by the loss of consumption based on a comparison of actual consumption from the grid to historical consumption levels. As such, a USG would encourage Transpower to manage its operational and maintenance decisions in order to minimise the amount of unserved energy. Transpower's annual liability exposure under a USG scheme would be capped.

6.4.10 Ideally, if a USG were implemented, Transpower would only be able to recover a target level of revenue from its customers through regulated charges under the Commerce Act. This would give Transpower incentives to outperform the target in order to retain the revenue it was not required to pay out in a given year.

6.4.11 The Commission envisages that the quality standards, the requirement to pay compensation and the cap on liability would be specified in the Rules and, if necessary, the Regulations. If a USG is not implemented until after the Authority is created, the USG would most likely need to be set out in the Code. The only matter that might need to be provided for in the TPM would be rules about how the cost of compensation is allocated among customers, but this might be

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[28] Paragraph 7.9.91 of the Commission's Summary of Submissions and Provisional Response to Submissions on the draft benchmark agreement and draft interconnection rules.

[29] Currently set at $20,000 MWh. This value is being reviewed.

unnecessary as this cost could be allocated by Transpower as part of its overheads under the TPM as currently drafted.

Voluntary insurance

6.4.12 Under the voluntary insurance option, Transpower would make insurance for loss of supply available to all customers (including parties, such as retailers, who are not designated counterparties). The requirement to offer insurance would be specified in the Rules. Parties could choose their level of insurance (in terms of $/MWh taking into account the potential for unserved energy valued at their own value of lost load and risk mitigation strategies. Transpower would base the premium on the customer's load factor, the assessed reliability of the relevant GXP and the expected level of supply interruptions using a detailed regulated pricing methodology.

6.4.13 The insurance scheme could be provided for either in the Benchmark Agreement or the Rules (or the Code once made). At this stage, it is unclear whether there would need to be anything relating to the insurance scheme in the price-quality path set by the Commerce Commission or any rules in the TPM about allocating the costs of the insurance scheme.

6.4.14 The stage 1 consultation paper asked two questions:

(a) should USG or voluntary insurance schemes be considered within the review; and

(b) are there other options for linking pricing and service that you think the Commission should consider?

6.4.15 Submitters gave views on issues wider than these two questions and also indicated that the consultation document had not provided sufficient detail on the USG scheme.

Views of submitters

6.4.16 Submitters generally supported performance incentives for transmission services, but a significant number considered such incentives should not be considered as part of the Review because they are not a priority or are better considered by the Commerce Commission. MEUG. Powerco, WPI and Todd Energy considered that a USG or a voluntary insurance scheme was worthy of further consideration. Transpower was particularly opposed to the USG and voluntary insurance scheme proposals, and included an appendix setting out its objections.

6.4.17 For those who supported a linkage between service quality and pricing, submitters were divided on how the link should be implemented with submitters noting that:

(a) any measures should be output-based as this is the most consumer-centric of approaches;

(b) any linkage should be by negotiation and reflected in the contractual relationship with Transpower i.e. should not be prescribed by the Benchmark Agreement or the Interconnection Rules;

(c) performances incentives should be based on comparing Transpower's national performance with international benchmarks; and

(d) if a USG or a voluntary insurance scheme was to be considered the costs should not be a pass-through on all customers.

6.4.18 There was negligible support from the supply side of the industry of the two schemes mentioned. Transpower, Vector and Powerco considered that the most appropriate mechanism will be via the individual price-quality path for Transpower under part 4 of the Commerce Act. The review and the resultant TPM is primarily an exercise in finding the best cost allocation methodology from a range of options consistent with the current regulatory framework. Linking price and service in the ways suggested will impact on Transpower's revenue which is straying from the original intent of the review. Submitters noted that the consideration of the TPM would be complicated by the inclusion of such schemes.

6.4.19 Customers of Transpower were concerned that the full cost of the schemes would be recovered from them without any improvement in Transpower's performance.

6.4.20 Todd Energy, MEUG and WPI considered that such schemes should be considered as part of the Review.

Commission's position

6.4.21 The Commission has reconsidered the relevance of this issue to the review and the appropriateness of the approaches. The conclusion is that price, and its links to the service provided, is an important issue which should be worked through.

6.4.22 Consideration of the submissions and the current regulatory and proposed regulatory regimes has meant that the issue will continue to be investigated but not as part of the review. The results of this work will be provided in a handover package to the Authority to assist it in its consideration of setting quality standards for Transpower for inclusion into the new Code.

6.5 Static reactive power compensation

The stage 1 consultation paper

6.5.1 One of the issues identified in the stage 1 consultation paper was whether the Commission should consider a methodology for allocating the cost of existing and new static reactive power assets as part of the review.

Views of submitters

6.5.2 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.

6.5.3 For those submitters who considered that it was not appropriate to consider reactive power compensation as part of the review, they commented 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.

6.5.4 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).

Commission position

6.5.5 On the basis of submissions received, and its own analysis, the Commission has decided to include the issue of static reactive power in the context of the review.

6.5.6 In the event that Transpower is required to develop a revised TPM, in response to revised Transmission Pricing Guidelines provided by the Commission, an extensive rework 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 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.

6.5.7 The Commission has identified three alternative options for consultation. These are outlined in the stage 2 consultation paper and further detail is provided in Appendix 5, along with supporting analysis.