Consultation Paper

Transmission Pricing Review: High-level options

Prepared by the Electricity Commission

October 2009

Executive summary

Introduction

1. This paper – covering high-level options for transmission pricing – is being released together with two other consultation papers on related issues. They are:

   (a) *Scarcity pricing and compulsory contracting: options*.

   (b) *Managing locational price risk: options.*

2. This paper is the first consultation paper to be published as part of the Electricity Commission's (**Commission**'s) review of transmission pricing. It introduces and summarises the work of the Commission's consultant, Frontier Economics, in determining possible high-level options for transmission pricing and poses questions for the high-level issues canvassed.

3. While all three consultation papers are stand-alone documents, the Commission recognises the strong linkages between the topics they cover. For this reason, the papers are being released with a common timetable for submissions.

4. The Commission is mindful that the consultation papers are being released while there is an on-going Ministerial review of the electricity market (**Ministerial Review**). As this paper presents high-level options there will be time to consider issues that arise from the Ministerial Review during the later stages of the projects.

5. Interested parties are invited to make submissions on this consultation paper.

Background

6. In New Zealand there is a prescribed process for the development of a Transmission Pricing Methodology (**TPM**) for allocating the costs of transmission services.

7. The Commission announced that it would undertake a wide-ranging review of transmission pricing in April 2009. This review is considering options for the allocation methodology for transmission costs, and will involve three analysis stages each of which will include public consultation. The final output of this

process will inform the Commission's decisions on the preferred option and the guidelines to be used in setting the TPM.

High-level options and filtering criteria

8. Frontier Economics has prepared a report for the Commission identifying high-level options for transmission pricing and proposing a set of criteria for narrowing down these options.

9. Frontier's framework for deriving the high-level options is based on the findings of previous reports prepared for the Commission on efficient pricing theory, international experience and current issues in the New Zealand market, as well as the range of relevant policy and regulatory considerations set out in the Electricity Act 1992 (**Act**), part F of the Electricity Governance Rules (**Rules**)[1] and the Government Policy Statement on Electricity Governance (**GPS**).

10. In order to distinguish high-level option issues from more detailed considerations, Frontier's approach has been to identify locational cost allocation issues as high-level and price structure issues as lower level. That is, the focus has been on the degree of locational differentiation of transmission charges.

11. In addition to the status quo transmission pricing arrangements, Frontier has identified three other high-level options that it believes are worthy of further investigation and consultation. These three other options are:

    (a) 'tilted' postage stamp approaches;

    (b) augmented nodal price signals; and

    (c) load flow-based approaches.

12. The current transmission pricing regime depends on nodal pricing, the Grid Investment Test (**GIT**) and deep connection definitions and the allocation of HVDC charges to South Island generators to provide locational signals for participant investment decisions. All the other high-level options involve further enhancing locational signals.

[1] Any reference to rules will be to rules in Section IV of part F of the Rules unless otherwise stated.

13. The tilted postage stamp approach is intended to provide broadly appropriate locational signals to generators and loads. Assuming the historical pattern of network flows continues into the future, it would mean imposing comparatively higher charges on generators in the South Island and loads in the North Island and lower charges on generators in the North Island and loads in the South Island.

14. The augmented nodal price signals option seeks to directly address the deficiencies in nodal energy prices created by excessive or premature network investment; and the issue that the value of reliability is not signalled in nodal prices. Under this regime:

    (a) transmission charges should be highest for those generators and loads that benefit most from excessive or premature network investment; and,

    (b) transmission charges should be lowest for those generators and loads that are made most worse off from excessive or premature network investment.

15. Load flow-based transmission pricing options involve a process of network analysis to attribute costs to participant connection points based on identification of the network assets ‘used’ to convey electricity from points of injection to points of withdrawal. Load flow approaches can be based on the topology of the existing network as in Australia (cost reflective network pricing (**CRNP)**) or on forward-looking network development costs, as in Great Britain (investment cost related pricing (**ICRP**)).

16. Further to these high-level options, there are four other key issues arising in the consideration of transmission pricing in this consultation paper. These are:

    (a) the approach to setting connection charges;

    (b) the treatment of transmission alternatives;

    (c) linking transmission pricing with service quality; and

    (d) static reactive power compensation.

Filtering criteria

17. Frontier has developed a number of criteria that could be used for narrowing down the high-level options outlined above for more detailed cost-benefit analysis at a later stage of the review. These are:

(a) divergence from [theoretically] optimal transmission investment;

(b) theoretical precision;

(c) locational hedging options;

(d) network topology;

(e) information requirements/Implementation difficulty;

(f) governance arrangements;

(g) good regulatory practice; and

(h) stakeholder acceptability.

18. Different options have different strengths and weaknesses across these filtering criteria.

Process

19. The Commission expects to undertake three analysis and consultation stages (at each of which it expects to publish a consultation paper and undertake public consultation):

(a) first, a review of high level options;

(b) secondly, an analysis to identify a short list of options; and,

(c) thirdly, a detailed evaluation of a preferred option for the allocation of transmission costs and, if the preferred option is a change from the status quo, the issuing of draft guidelines for consideration (as required by Rule 4).

20. If during or after consultation the Commission decides that changes to the regulatory parameters (eg the pricing principles) should be considered, this may involve an additional step in the process.

21. If the preferred option leads to significant changes in charges to participants, the review will consider options for transitional arrangements.

Glossary of abbreviations and terms

Act	Electricity Act 1992
APR	Annual Planning Report published by Transpower
Commission	Electricity Commission
Connection Code	Connection code as set out as schedule 8 to the Benchmark Agreement
Consultation paper	The Electricity Commission's Transmission pricing review: high-level options consultation paper
CRNP	Cost reflective network pricing
DSM	Demand side management
DTC	Designated Transmission Customer
Frontier report	The Frontier Economics Ltd report*, Identification of high-level options and filtering criteria*, prepared for the Commission, September 2009
FTR	Financial transmission right
GIT	Grid investment test set out in schedule F4 of part F of the Rules
GPS	Government Policy Statement on Electricity Governance dated May 2009
GUP	Grid upgrade plan
GXP	Grid exit point
HVAC	High voltage alternating current
HVDC Link	High voltage direct current link between Benmore and Haywards
ICRP	Investment cost related pricing
LRA	Locational rental allocation
LRMC	Long run marginal cost
MDP	Market Development Programme
Minister	Minister of Energy and Resources
Ministerial Review	The Ministerial Review of the electricity market
NAaN	Transpower's North Auckland and Northland grid upgrade proposal as approved by the Commission in 2009
NIGU	Transpower's North Island Grid Upgrade proposal as approved by the Commission in 2008
PF	Power factor

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	The Electricity Commission’s review of transmission pricing
Rules	Electricity Governance Rules 2003
Strata report	The Strata Energy Consulting discussion paper concerning transmission pricing issues identified by the TPTG, dated August 2009
TPM	Transmission Pricing Methodology
TPTG	Transmission Pricing Technical Group
USG	Unconditional Service Guarantee

Contents

1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 The Commission has launched a Market Development Programme (**MDP**) to improve the performance of the electricity market. The MDP is designed to address two key areas of concern:

(a) **supply security** – although actual power cuts due to insufficient generation have not occurred in New Zealand since the 1970s, there is a strong perception that the system is unreliable. The succession of supply 'scares' and frequent calls for widespread voluntary power savings (three times since 2001) reinforce this perception. There is also doubt about whether current arrangements provide sufficient reward for resources (generation and/or demand-side response) which are required very infrequently to meet peak demand, or to offset low hydro generation during extreme droughts; and

(b) **electricity prices** – prices have increased for all customer groups, but have risen especially sharply for residential users. There is uncertainty over whether the increases reflect rising costs, inefficiencies in the sector or the exercise of enduring market power.

1.1.2 Because of the complex and interlinked nature of the electricity supply chain, the MDP is being taken forward as an integrated package of measures. Consultation papers on individual measures within the MDP will be released progressively over the next few months.

1.1.3 This paper describes a major element of the MDP, which is the review of transmission pricing.

1.1.4 The Commission has initiated a Transmission Pricing Review (**review**) to undertake a wide-ranging review of options for the allocation methodology for transmission costs.

1.1.5 In the first stage of this review, the Commission has been considering issues with current transmission pricing and high-level options for transmission pricing. This consultation paper is the first to be published as part of this review and concludes the first stage of the review.

1.1.6 Two other consultation papers on related issues are being released alongside this paper. They are:

(a) *Options for the possible introduction of scarcity pricing or compulsory contracting mechanisms* – These mechanisms are intended to improve security by increasing the expected reward for providers of generation/demand response during periods of tight supply.

(b) *Options for managing locational price risk* – these mechanisms are designed to facilitate competition in the retail and hedge contract markets. This is important in its own right, but would also help market participants manage some of the additional spot risk that could arise with the introduction of scarcity pricing.

1.1.7 While all three consultation papers are 'stand-alone' documents, the Commission recognises the strong linkages between the topics that they cover. For this reason, the papers have been released as a suite, with a common timetable allowed for submissions.

1.1.8 The Commission is mindful that these papers are being released while there is an ongoing Ministerial Review of the electricity market (**Ministerial Review**).

1.1.9 The Ministerial Review discussion paper: *Improving Electricity Market Performance* made a number of recommendations that align with the MDP initiatives and recognised that the Commission has a review of transmission pricing underway. Interested parties have made submissions in response to that discussion paper.

1.1.10 All three of the Commission's consultation papers present options rather than a formal proposal and as such there will be time to consider issues that arise from the Ministerial Review during later stages of these three – and other MDP – projects where the options are being refined.

1.2 Invitation to conference

1.2.1 The Commission invites interested parties to a conference to be held in Wellington on 29 October 2009. This one-day conference will cover the three consultation papers outlined above as well as other elements of the MDP. This conference is intended to assist interested parties in considering the consultation papers with a view to making submissions.

1.2.2 Details on this conference and on how to register will be made available on the Commission's website, http://electricitycommission.govt.nz/opdev/mdp.

1.3 Purpose of this paper

1.3.1 This paper:

(a) provides a brief background to transmission pricing and to the transmission pricing review that the Commission is undertaking;

(b) introduces and summarises the work of the Commission's consultant, Frontier Economics, in determining possible high-level options for transmission pricing in New Zealand;

(c) identifies high-level issues for public consultation; and

(d) invites submissions on the issues and options canvassed in this paper, including in particular the questions set out in it and restated in section 5.

1.4 Submissions

The Commission's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Commission, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@electricitycommission.govt.nz with Consultation Paper—Transmission pricing review: high-level options in the subject line.

If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Kate Hudson
Electricity Commission
PO Box 10041
Wellington 6143

Kate Hudson
Electricity Commission
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

Fax: 0-4-460 8879

1.4.1 Submissions should be received by 5pm on 7 December 2009. Please note that late submissions are unlikely to be considered.

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

1.4.3 If possible, submissions should be provided in the format shown in Appendix 1. Your submission is likely to be made available to the general public on the Commission’s website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.

2. Background

2.1 Transmission pricing

2.1.1 Transpower determines its revenue requirement (covering both sunk and new investments) subject to the constraints of the Commerce Act 1986. The TPM sits alongside this to determine how Transpower's total revenue is recovered from its customers.

2.1.2 The pricing of transmission services has been a difficult issue both in New Zealand and internationally. Historically, participants in New Zealand have been unable to agree to voluntary contractual arrangements, and past litigation has resulted in a prescribed process for the recovery of the costs of transmission and the development of a TPM.

2.1.3 This process is described in Section IV of part F of the Rules. It sets out a process whereby:

(a) the Commission prepares an issues paper on the process to be followed and guidelines to be used by Transpower in preparing a TPM (rule 4);

(b) the Commission consults on the process and guidelines (rule 5) and then finalises and publishes them (rule 6);

(c) Transpower develops a TPM following the process and guidelines and submits it to the Commission (rule 7);

(d) if the Commission is satisfied that the proposed TPM meets the relevant requirements, following consultation, it recommends the TPM to the Minister of Energy[2] for inclusion into the Rules (rule 8).

2.1.4 The purpose of the TPM is to ensure that the full economic costs of Transpower's services are allocated in accordance with the pricing principles set out in rule 2 (**Pricing Principles**) (rule 1).

2.1.5 The current TPM is based – with some refinements – on the TPM that was developed by Transpower and first applicable from 1 April 1999, before the Rules were in place[3].

2.1.6 In the decade prior to 1999 the development of transmission pricing began with unbundling of transmission costs from the bulk supply tariff. Fully separated transmission charges were then developed to allow for Transpower's separation

---

[2] The current Minister is titled the Minister of Energy and Resources, but the Act refers to the Minister of Energy.

[3] A report prepared by Strata Energy Consulting Report *on Transmission Pricing Methodologies – 1988 to 2008* documents the changes in Transmission Pricing Methodologies and is available at http://www.electricitycommission.govt.nz/opdev/transmis/tpr/index.html#high-level-options-investigation.

from the Electricity Corporation of New Zealand (ECNZ) in 1994. Transpower continued developing its TPM with the allocation of shared network costs being based, at least partially, on load flow analysis.

2.1.7 The 1999 TPM represented a shift from the previous methodologies used by Transpower to allocate transmission costs. One of the key differences from earlier approaches was the introduction of three distinct charges:

(a) connection charges for all generators and offtake customers for assigned connection assets. This methodology created a new definition for connection assets, which removed the previous distinction between 'deep connection' assets for generators and 'shallow connection' assets for offtake;

(b) interconnection charges for offtake customers allocated only by peak demand ($/kW). This removed the previously used transport charge which allocated 50% of the High Voltage Alternating Current (**HVAC**) grid assets using a load flow model and the access charge which recovered the residual revenue requirement. The interconnection charge recovered the residual revenue not recovered from other charges; and

(c) explicit High Voltage Direct Current (**HVDC**) charges for the HVDC link for South Island generators only, allocated by peak injection MW.

2.1.8 The current TPM is based on these three charges but has introduced further refinements – such as a change to allocating interconnection charges according to the regional coincident peak demand **(RCPD**) and a refinement of the definition of connection assets. It has been in place since April 2008.

2.1.9 In 2004 the Commission first began consulting on how to allocate the costs of transmission, and at that time it considered whether to conduct a more comprehensive review of transmission pricing (encompassing locational pricing). However, the Commission decided it was preferable to implement a methodology in the short term and noted that a review was intended in the future.

2.1.10 In the *Transmission Pricing Methodology Final Decision Paper*[4] dated 7 June 2007 the Commission noted that it would include such a review in its future work programmes, and that the review would be comprehensive and would be conducted through a formal process.

2.1.11 The Commission announced that it would undertake this wide-ranging review of transmission pricing in April 2009 and published an overview of the review.[5]

---

[4] Transmission Pricing Methodology Final Decision Paper, available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpm/index.html#final

[5] *Overview: Transmission Pricing Review Project*, available at http://www.electricitycommission.govt.nz/opdev/transmis/tpr

2.1.12 A review of transmission pricing is now timely for the following reasons:

(a) The Commission has approved significant transmission investment. The Commission has approved transmission projects in excess of $2.6 billion. The commissioning dates of a number of these projects mean that their costs will be recovered from the 2012 pricing year onwards.

(b) Power flows may change due to investment in transmission, generation and location of demand (and have indeed changed since the development of the current TPM).

(c) There is a need to reconsider whether the current TPM, the grid investment test (**GIT**), the deep connection definition and nodal prices are resulting in efficient location decisions for investment.

(d) There is an increased emphasis on security of supply.

(e) The TPM has evolved over the last 15 years but the fundamental design has remained the same. There may be lessons to be learned from international experience in the allocation of transmission costs.

(f) Several parties have made requests to the Commission both formally[6] and informally[7] to review aspects of the TPM.

(g) Current MDP initiatives may impact on the investment signals for transmission, generation and load. These include:

(i) the possible introduction of scarcity pricing or compulsory contracting – if one of these options is selected, this should lead to improved incentives for both generation and demand by addressing opportunities for cost-shifting;

(ii) the possible introduction of mechanisms for managing locational price risk; and

(iii) the introduction of arrangements for dispatchable demand.

2.2 Review of transmission pricing

2.2.1 The review is considering options for the allocation methodology for transmission costs. The review involves consultation with interested parties and economic, technical and legal analysis of the options being considered.

2.2.2 As previously noted, the Commission is planning three analysis stages, culminating with a rule 4 issues paper on the process to be followed and

---

[6] Letters from Meridian dated 14 Sept 2007 and from TrustPower dated 14 January 2007 are available at: http://www.electricitycommission.govt.nz/opdev/transmis/tpm/index.html#correspondence.

[7] Major Electricity Users Group (MEUG)

guidelines to be used by Transpower in preparing a TPM (if a new approach is adopted). Each stage will include an issues paper for consultation with the final issues paper planned for the end of 2010. This paper is the first of these consultation papers. This process goes beyond what is required by the Rules, and reflects the Commission's desire to begin with first principles and also to ensure that interested parties have an opportunity to influence all stages of the process.

2.2.3 The Commission expects that any subsequent changes to the TPM will be effective from the 2012 pricing year, although this will be dependent on the final option selected and the implementation requirements. As noted above, this should coincide with the approximate commissioning dates of a number of significant transmission investments and will therefore be in step with changes in the costs to be recovered and consequential pricing impacts.

2.2.4 The Commission recognises that changes to the allocation of transmission prices may result in value transfers between parties. For this reason the Commission encourages strong input from interested parties into the review. As well as written submissions, the Commission expects to provide opportunities for input through conferences and/or briefings as the review progresses.

2.2.5 The Commission has established a working group known as the Transmission Pricing Technical Group (**TPTG**)[8]. This group is made up of technical specialists nominated by interested parties and is providing specialist review and input. During the first stage of the review this group has been particularly considering issues with the current transmission pricing, international comparisons and efficient pricing theory.

2.2.6 Whilst the review is considering a range of issues and will investigate a number of high-level options, the aims are to contribute to the following efficiency outcomes:

(a) efficient network investment – better downstream management of load and distributed generation can defer transmission (and distribution) investment;

(a) efficient facilitation of entry and location decisions by generation – by transmission cost signalling; and

(b) recovery of sunk costs in a manner that minimises distortions to production/consumption and investment decisions by grid users and consumers.

2.2.7 In considering the issues the review must take account of the relevant policy and regulatory considerations. These are outlined in paragraphs 3.2.18 belowto

[8] Membership and meetings details are available on the Commission's website: http://www.electricitycommission.govt.nz/advisorygroups/pjtteam/tptg/index.html

3.2.22 below. Importantly, as with any of the Commission's work, the review must consider options and issues to ensure consistency with the Commission's principal objectives. These are set out in the s172N of the Act and are:

(a) to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable and sustainable manner; and

(b) to promote and facilitate the efficient use of electricity.

2.3 The Review process

2.3.1 The Commission expects to undertake three analysis and consultation stages:

(a) first, a review of issues with current transmission pricing and identification of high-level options;

(b) secondly, an analysis to identify a short list of options; and

(c) thirdly, a detailed evaluation of a preferred option for the allocation of transmission costs and if the preferred option is a change from the status quo, the issuing of draft process and draft guidelines for consideration.

At each stage the Commission expects to publish a consultation paper and undertake public consultation.

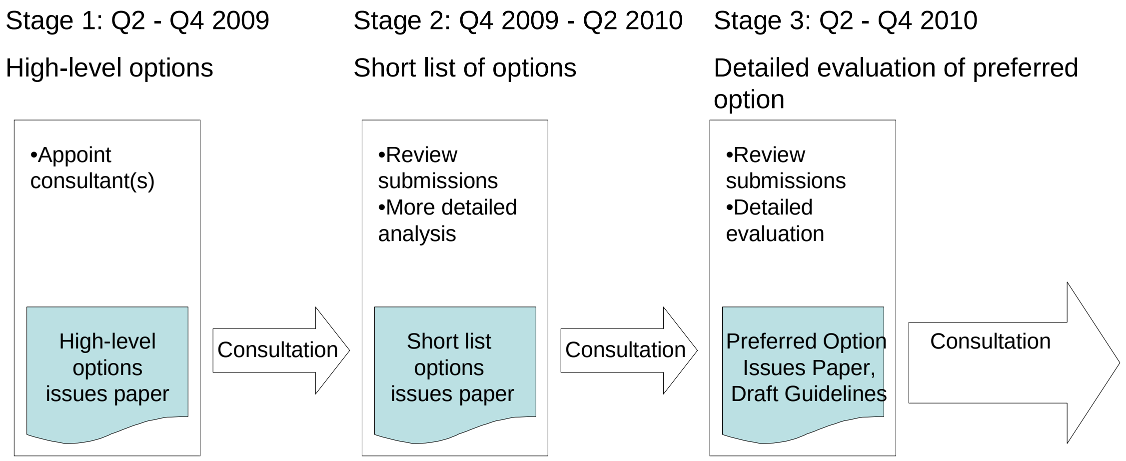
2.3.2 If after consultation the Commission decides that changes to the regulatory parameters (eg the pricing principles) should be considered, this may involve an additional step in the process.

2.3.3 If the preferred option is a new approach to transmission pricing, the Commission will publish an issues paper detailing the preferred option. The Commission anticipates that this issues paper would incorporate the draft process to be followed and draft guidelines to be used by Transpower in preparing the new TPM (as required by rule 4). The process for subsequent development of a new TPM is set out in rules 5 to 11.

2.3.4 If the preferred option leads to significant changes in charges to participants, the review will consider options for transitional arrangements.

2.3.5 The three review and analysis stages are set out below in Figure 1. The timeframes below are approximate and may be subject to change.

Figure 1 Overview of the review process



2.3.6 The Commission expects to release a short list options issues paper in early to mid 2010**.**

3. High-level options and filtering criteria

3.1 Introduction

3.1.1 Frontier Economics has prepared a report for the Commission identifying high-level options for transmission pricing and proposing a set of criteria for 'filtering' or narrowing down those options (**Frontier report**). The Frontier report is attached as Appendix 2.

3.1.2 The purpose of this section of the consultation paper is to identify issues for public consultation arising in relation to the Frontier report.

3.1.3 The structure of this section follows the structure of Frontier's report. That report addressed the following issues:

(a) framework for deriving high-level options;

(b) scope of high-level options;

(c) relevant policy and regulatory considerations;

(d) high-level options – the status quo, 'tilted' postage stamp, augmented nodal price signals and load flow-based approaches;

(e) further issues, such as the treatment of connection costs, transmission alternatives, service quality and pricing and reactive power compensation; and

(f) filtering criteria.

3.1.4 This section briefly summarises the discussion of these topics in the Frontier report and poses questions for consultation.

3.1.5 This remainder of this section is structured as follows:

(a) Section 3.2 raises questions surrounding the framework for deriving high-level options for transmission pricing in New Zealand.

(b) Section 3.3 raises questions regarding the proposed high-level options.

(c) Section 3.4 raises questions relating to further issues.

(d) Section 3.5 raises questions relating to the proposed filtering criteria for narrowing the choice of high-level options.

3.1.6 The questions posed are also summarised in the final section of this paper.

3.1.7 This paper also briefly discusses relevant Commission work or high-level analysis related to this high-level options consultation. For example the Commission has included some information on the possible influence the existing arrangements have on generator location decisions , on liability and compensation mechanisms and on the allocation of reactive power costs.

3.2 Framework for deriving high-level options

3.2.1 Frontier's framework for deriving high-level transmission pricing options is based on the previous reports prepared for the Commission on efficient pricing theory[9], international experience[10] and current issues in the New Zealand market[11], as well as a the range of relevant policy and regulatory considerations set out in the Act, Rules and the GPS.

(a) Findings of the efficient pricing theory report

3.2.2 The Frontier report noted that an energy market with 'full' nodal pricing (incorporating full pricing of congestion and losses and no price caps below the value of unserved energy) ought to provide efficient signals for the use of the existing transmission network. That is, a market with full nodal pricing should provide appropriate signals for participants' operational decisions.

3.2.3 The Frontier report further noted that if the transmission system is able to be augmented perfectly efficiently, and there are no economies of scale in generation, load or transmission, full nodal pricing should also provide appropriate signals for investment by generators and loads. That is, where these two conditions are present, nodal pricing should provide investors with incentives to choose the optimum technology, location and timing of new generation plant and load facilities.

3.2.4 The Frontier report acknowledged, however, that there are factors that may inefficiently (in a strict economic sense) suppress nodal prices.[12] These are:

(a) economies of scale in investment;

(b) 'over-caution' of network planners and regulators and the use of deterministic reliability investment criteria which may lead to early

[9] See Frontier Economics, *Theory of efficient pricing of electricity transmission services*, July 2009, available at http://www.electricitycommission.govt.nz/advisorygroups/pjtteam/tptg/meetings/28jul09/index.html

[10] See Frontier Economics, *International transmission pricing review*, July 2009, available at http://www.electricitycommission.govt.nz/advisorygroups/pjtteam/tptg/meetings/28jul09/index.html

[11] See Strata Energy Consulting, a discussion paper concerning transmission pricing issues identified by the TPTG, August 2009, available at http://www.electricitycommission.govt.nz/opdev/transmis/tpr/index.html#high-level-options-investigation

[12] A paper prepared for the Commission in 2004 by Covec also considered the extent that nodal prices incorporate full pricing of congestion and losses and value security of supply. Covec, *Locational signals for new investment*, August 2004 available at: http://www.electricitycommission.govt.nz/infopapers/index.html

investment or over-investment in transmission due to considerations of economic risk of late commissioning; and

(c) inaccurate pricing of supply security.

3.2.5 The first two factors can both lead to investment in the system ahead of demand and consequently may suppress nodal prices. In respect of the third factor listed above, the value of network security and reliability is not currently signalled in nodal prices. In fact when supply capacity at a node is constrained and load cannot be served, forced disconnection lowers the nodal prices rather than increasing them to reflect scarcity value.

3.2.6 This issue was outlined in Frontier's earlier report: *Theory of efficient pricing of electricity transmission services*. This is also one of problems that could be addressed by scarcity pricing, as set out in the related Commission consultation paper: *Scarcity pricing and compulsory contracting: options*.

3.2.7 In combination these three factors will tend to 'undersignal' the importance of participants locating in areas where they are least likely to bring forward further augmentation of the transmission grid.

3.2.8 In order to consider whether nodal pricing provides appropriate signals for investment by generators and loads, the Commission is interested in each of the three factors. The first two are considered further below.

3.2.9 Box 1 considers the issue of whether there are economies of scale demonstrated in transmission investment.

Box 1: Economies of scale in transmission investment

Economies of scale are strongly demonstrated in electricity transmission. This is because:

(a) there are, in general, falling average costs for investment – it is cheaper to build a line of a certain capacity than two lines of half that capacity;

(b) technical efficiency considerations can lead to economies of scale – higher voltage lines are physically larger but transmit electricity more efficiently; and,

(c) environmental considerations can lead to economies of scale – it is preferable to build one set of overhead lines rather than two, and to complete undergrounding work in one project. Timeframes for obtaining environmental consents and property rights may also be significant.

Recent examples of economies of scale in transmission investments include the North Island Grid Upgrade (**NIGU**) and the North Auckland and Northland (**NAaN**) cable investments.

In comparing investment options for NIGU, based on the assumptions made regarding future generation location, the recently approved 400kV capable transmission line between Whakamaru and Otahuhu was demonstrated to be more economically efficient than the 220kV alternative that was used as a comparison in the GIT. If these two options were built at the same time two 220kV double circuit lines would provide a similar capacity to one 400kV double circuit line, with the 400kV option costing around 10% less ($500 million rather than $550 million).

For the NAaN project cable investments the largest feasible cable size circuits were selected by Transpower, indicating that these higher ratings provided the highest overall net benefits.

3.2.10 Box 2 below considers, at a high level, whether there is likely to be an impact on nodal price differentials from the transmission system being augmented ahead of time as a result of early investment or over-investment in transmission due to considerations of economic risk from late commissioning and the use of deterministic reliability investment criteria.

Box 2 The possible impact on nodal prices of the transmission system being augmented ahead of demand

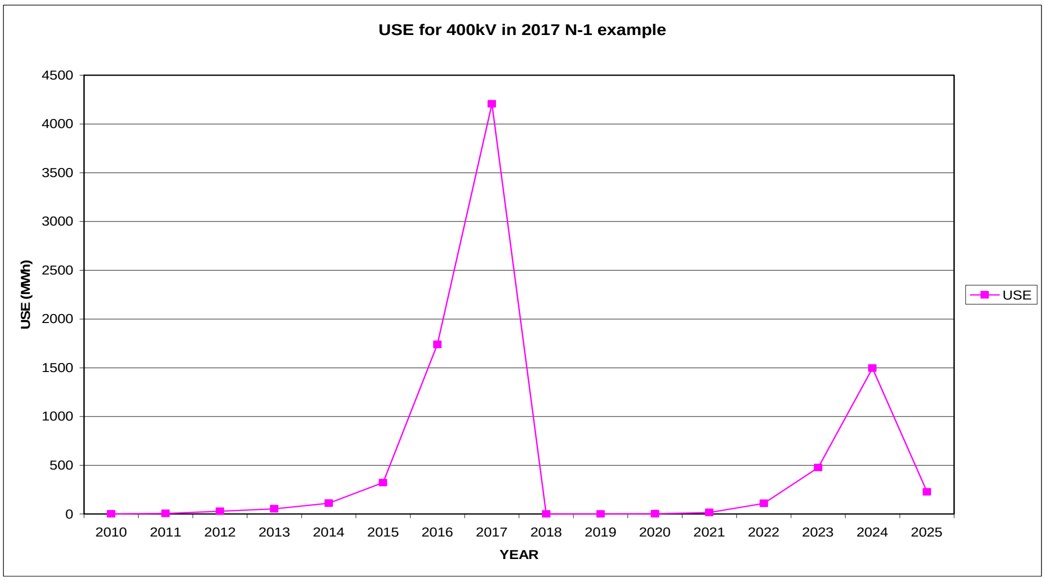
The NIGU project was approved for commissioning in 2011 four years ahead of the technical need date. The approval for early commissioning recognised the importance of mitigating risks in project delivery and that early commissioning had a small net economic cost when compared with the asymmetrically high costs if the assets were provided too late.

Figure 2 below provides analysis completed as part of the NIGU approval process. For this discussion the analysis is indicative and considers the expected unserved energy if the project had been approved for commissioning in 2017[13]. The chart shows a sharp increase in expected unserved energy. This indicates the influence of commissioning ahead of technical need-date and also signals the potential for asymmetrically high costs if upgrades are provided too late. If transmission investments were to be funded from loss and constraint rentals then most of the funding for those investments – as well as the returns to investors in generation projects – would occur close to the technical need date of the next increment of transmission investment. Consequently even relatively small advancements in transmission investment commissioning dates will impact significantly on the signals given by nodal prices for investment in new generation and load. This suggests significant practical issues with relying solely on nodal pricing signals to promote the appropriate nature, location and timing of

[13] This analysis was prepared for the initial NIGU decision, at which time the technical need date was indentified at 2017. Analysis of the amended proposal subsequently identified a 2015 need date.

generation and load investment.

Figure 2: **Unserved energy (USE) for 400kV in 2017 N-1 example**



The application of non-economically-based deterministic reliability standards

The Grid Reliability Standards (GRS) require a minimum of an n-1 reliability standard in the core grid. The outcome of the application of this deterministic standard can be transmission investments being made in advance of the need-date indicated by economic analysis, and at other times, later than the need-date.

3.2.11 Frontier noted that if the three factors outlined in paragraph 3.2.4.inefficiently suppress nodal prices, then some mechanism or pricing regime will be needed to augment or supplement nodal prices in order to promote efficient load and generation investment decisions.

3.2.12 Finally, the Frontier report observed that if nodal pricing signals are muted due to early augmentation of the grid, both generators and loads need to face locationally differentiated transmission charges. The current TPM allocates connection charges to both generators and load, and HVDC charges are allocated to South Island generation plant. However, under current arrangements HVAC interconnection costs are allocated to load only.

3.2.13 Box 3 below considers the extent to which both the current TPM and nodal pricing influences generator location decisions, and also considers at a high level whether these influences may be sufficient.

Box 3 The extent that the current TPM and nodal pricing influence generator location

The Commission is interested in the following:

- the extent that the TPM and nodal pricing may influence generation location; and,
- whether these influences may provide insufficient locational signals by considering analysis of recent transmission investments and recent or possible generation investment.

The current TPM influences generator location decision-making to a limited extent through signalling [deep connection] spur line connection costs and the impact of the HVDC charge. Generators do not otherwise meet grid charges and so these costs are not signalled and therefore cannot influence generator location decisions.

Nodal pricing signals constraints and the marginal value of losses and this could potentially provide a substantial locational signal. In general, constraints on the grid in future years are expected to be minimal as reliability driven investment is expected to continue to reduce these, but losses will continue.

Setting aside whether nodal prices may or may not be suppressed by factors such as economies of scale in transmission investment discussed in the Frontier report, nodal prices will be a consideration in generator location decisions. An investor in new generation will consider forecasts of nodal prices and supply contracts at possible locations.

However, the extent that nodal prices will influence a generator's location decision will depend on a number of factors including:

- the extent of nodal price differentials between possible locations;
- the impact that the new generator may have on nodal prices. When a generator locates at a node it should have the effect of reducing prices at that node. Large generation investments have a significant impact on marginal losses, and therefore on nodal prices. However, the generator may not be able to capture a significantly large enough share of this economic benefit as a locational signal;
- planned transmission investment that might reduce constraints and nodal price differentials; and
- other locational-dependent commercial factors such as availability of fuel, fuel transport costs, ability to gain resource consent and any connection and HVDC

costs if applicable.

In considering whether the locational signals from the TPM and nodal pricing may be insufficient it is useful to consider both the possible efficiency gains of generation investment compared with those of recent transmission investment approved and the role of transmission costs in possible generation location decisions.

Analysis of the possible efficiency gains of generation investment compared to transmission investment on the recent investment approvals of the NIGU and NAaN projects is informative.

As revealed in the Commission's reasons for decision documents for those two projects, if new generation were located in the Auckland or North Auckland regions a large component of the substantial transmission investment currently underway could have been unnecessary. Analysis based on considerations made when the transmission projects were approved identifies approximately $0.5 billion of net benefit of locating generation close to Auckland, since that would avoid a significant portion of the transmission costs associated with the NAaN and NIGU investments.

However, in its deliberations the Commission concluded that it was not certain that generation would be built within the 20-year timescale relevant to the application of the GIT.

In 2008 a 200MW OCGT plant was committed for construction in Taranaki. Had this generation instead been committed at locations in the Auckland and North Auckland area (for a similar cost), then, as noted above, substantial transmission costs would have been avoided.

An independent analysis[14] indicates that additional gas transmission costs of approximately $60m would have been incurred if the plant was instead located in the Auckland area. However under the current TPM, the investor faced no difference in transmission charges between locating in Taranaki or Auckland as generators do not pay interconnection charges.

Similarly generation investment at the top of the South Island would have avoided $65m of Tactical Transmission Upgrades (TTUs 15-18) approved by the Commission in November 2005. Further substantial transmission investment in the South Island is now being considered by Transpower and the need for this could be avoided by generation investment in the northern South Island.

While a TPM that signalled locational costs would not necessarily have ensured that such plant was built, providing stronger locational prices consistent with the long run

[14] A report prepared for the Commission by Independent Technology Ltd, *Gas Pipeline Upgrade Cost Estimate* available at: http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/gup/naan/May2008/advice-corres/independent-tech.pdf

marginal cost (**LRMC**) of transmission may give greater confidence that transmission costs would be sufficiently taken account of when generation investors make location decisions.

Analysis of generation investment over the last decade reveals that the majority of new investment has been in the North Island (over 80% excluding embedded generation) suggesting that current arrangements[15] may at least be achieving locational signalling between the North and South Islands.

Further while marginal loss factors provide some locational signal they do not currently reflect the value of security (value of unserved energy) through nodal prices which is used to justify transmission reliability investment using the GIT. Therefore, it is also not possible currently for nodal pricing to influence generator location decisions for grid reliability reasons.

Q 1.	To what extent do you agree that nodal prices can provide efficient signals for the use of the transmission network?
Q 2.	To what extent do you agree that nodal prices can provide efficient signals for investment in generation and load projects?
Q 3.	Do you consider that the nodal prices in New Zealand may be inappropriately suppressed due to the transmission system being augmented ahead of demand?
Q 4.	Can you provide examples where a transmission alternative could have been undertaken instead of an investment in the grid?
Q 5.	Do you agree that if locational transmission pricing signals are required to promote efficient participant investment decisions, both generators and loads ought to face these signals?

(b) Findings of the international review report

3.2.14 Frontier's international review report examined 15 jurisdictions[16], including the Australian NEM, Great Britain, several United States markets and some progressive European, South American and Asian markets. The report considered not only the prevailing transmission pricing regime, but also the

[15] HVDC costs have been met by South Island generators since 1996.

[16] The fifteen jurisdictions are Argentina, Australia (NEM), Chile, Germany, Great Britain, New Zealand, Norway, Singapore, South Korea, Sweden, United States (PJM, New York, California, New England and Texas). See Frontier Economics, *International transmission pricing review*, July 2009, available at http://www.electricitycommission.govt.nz/advisorygroups/pjtteam/tptg/meetings/28jul09/index.html

energy market pricing arrangements. Perhaps unsurprisingly, it found that there tended to be a trade-off between the degree of locational granularity of energy market pricing and the degree of locational transmission pricing.

Q 6.	Are there any other jurisdictions whose electricity market arrangements should be examined to assist in the development of high-level transmission pricing options for New Zealand?

(c) Findings of the Strata report

3.2.15 Strata Energy Consulting prepared a paper for the Commission, *A discussion paper concerning transmission pricing issues identified by the TPTG*, (**Strata report**) which Frontier reviewed.

3.2.16 The Strata report highlights a number of observations and concerns raised by the TPTG. These were not the unanimous views of the group and some of the observations are contradictory. Notwithstanding this, Frontier has identified observations or issues from the Strata report relevant to this high-level options review. The issues that Frontier considers are relevant to the high-level options review are:

- The pricing principles in Rules 2.1-2.5 potentially conflict with one another. The TPTG suggests that the Commission considers a review of the pricing principles.
- Nodal pricing signals and the GIT may provide insufficient signals as to the LRMC of locating in particular areas, particularly for generators.
- The beneficiary pays philosophy underlying the HVDC charge is partial (as it falls on South Island generators only) and distorts new generator location decisions.
- Potential providers of transmission alternatives must contract with Transpower rather than being directly eligible for a regulated revenue source.
- The TPM does not link transmission prices paid by particular customers to the service levels they request or receive.
- Parties investing in transmission connection assets should receive physical ‘capacity rights’.

Q 7.	Do you agree that the summarised issues Frontier identified from the Strata report are correct and relevant?
Q 8.	Are there other issues with the current transmission pricing that you think should be considered at this high–level options stage?

(d) Scope of high-level options

3.2.17 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. That is, the focus at this high-level options stage of the review has been on the degree of locational differentiation of transmission charges. Having said that, there are some high-level options that explicitly encompass both cost allocation and price structure.

Q 9.	Do you think it is appropriate to focus on locational cost allocation issues – as opposed to pricing structure issues – at this high-level stage of the review?

(e) Relevant policy and regulatory considerations

3.2.18 In addition to the background papers, the selection of high-level options must also take account of the Commission's objectives for the review. These objectives require that the preferred option must:

- be consistent with the Commission's principal objectives and specific outcomes set out in section 172N of the Act;
- be consistent with the Pricing Principles;
- be consistent with the relevant GPS objectives and outcomes;
- take into account practical considerations;
- take into account transaction costs - the preferred high-level option should not incur unreasonable transaction costs; and
- take into account the desirability for consistency and certainty for both consumers and the industry.

3.2.19 The Commission's principal objective in section 172N of the Act requires the Commission to:

(a) ensure that electricity is produced and delivered in an efficient, fair, reliable and environmentally sustainable manner; and

(b) promote and facilitate the efficient use of electricity.

3.2.20 The Pricing Principles are as follows:

2.1 the costs of connection and use of system should as far as possible be allocated on a user pays basis;

2.2 the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options;

2.3 pricing for new generation and load should provide clear locational signals;

2.4 sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions made by grid users;

2.5 the overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints; and

2.6 transmission pricing for investment in the grid should recognise the linkages with other elements of market pricing (including the design of the financial transmission rights regime under section V, and any revenues from financial transmission rights).

3.2.21 The Pricing Principles are directed at promoting various aspects or dimensions of economic efficiency.

3.2.22 Paragraph 99 of the GPS states that the Commission should ensure that certain principles are applied by Transpower in developing any transmission pricing methodology and by the Commission in approving it. These GPS principles broadly resemble the Pricing Principles. One of the key differences is the Pricing Principles require that both connection and use of system costs be allocated as far as possible on a user-pays basis whereas the GPS only refers to the costs of connection. Another key difference is the inclusion of rule 2.6. This principle, which is absent from the GPS principles, requires regard to be had to the role of nodal pricing and the design and application of a financial transmission rights (**FTR**) regime.

3.2.23 Frontier expresses the view, and the Commission agrees, that in virtually all circumstances it will not be possible to apply all of the relevant considerations equally. This will typically require trade-offs to be made between the principles when applying them to the development of suitable high-level options. Rule 3 specifically provides for the resolution of conflicts in applying the Pricing Principles.

Q 10.	Are there any particular Pricing Principles that ought to be given precedence over others?

3.2.24 The Commission understands that there may be concerns around the workability of the Pricing Principles – the TPTG has raised this point with the Commission.

Frontier considers that any issues can be resolved using the process as stated in Rule 3.

3.2.25 The Commission does not consider that it is appropriate to review the Pricing Principles at this time. This is particularly the case in the context of the Ministerial Review, a possible outcome of which is that the Commission may be replaced with an Electricity Market Authority that:

(a) continues with the transmission pricing work; but

(b) has different statutory objectives and outcomes.

Q 11.	Do you agree that it is not appropriate to review the Pricing Principles at this time? If not, why not?

3.3 High-level options

3.3.1 In the high-level options report, Frontier identified the status quo arrangements and three other high-level options as being worthy of further investigation and consultation. These three other options are:

- ‘tilted’ postage stamp approaches;
- augmented nodal price signals; and
- load flow-based approaches.

3.3.2 These are briefly outlined as follows, and are set out in more detail in the Frontier report.

Option 1: Status quo arrangements

3.3.3 The current transmission pricing regime comprises:

- a connection charge that recovers the costs of dedicated and spur line assets connecting a participant to the interconnected grid;
- an interconnection charge imposed on loads that is the function of both a postage stamped interconnection rate and the customer’s contribution to the regional coincident peak demand (**RCPD**); and
- a postage stamp charge on South Island generators to recover the costs of the existing HVDC link and any augmentations to it.

3.3.4 Frontier suggests that the current approach reflects a view that there is little need for transmission pricing to provide additional locational signals for participant investment decisions on top of nodal pricing in the energy market, charging load an interconnection rate based on the customer's contribution to the RCPD and charging participants for the spur line connection assets and the GIT.

Q 12.	Do you think existing TPM, combined with the GIT and nodal pricing provide appropriate operational and investment signals to existing and prospective participants? Please give examples or reasons for your answer.
Q 13.	If not, are there relatively minor modifications that could be made to the existing regime to enable it to provide appropriate locational signals?
Q 14.	Even if the existing approach does not provide efficient signals to participants, to what extent are participants' investment decisions likely to be distorted as a result?

Option 2: 'Tilted' postage stamp approaches

3.3.5 Under this approach, charges are postage stamped, but are higher for loads in predominantly importing regions and lower for loads in predominantly exporting regions. If future load growth in New Zealand follows historical trends, this approach should lead to higher charges for loads in the North Island than loads in the South Island. The tilted postage stamp charge could also apply to generators in an inverse manner. That is, generators in the North Island could face a lower charge (or even a subsidy) than generators in the South Island.

3.3.6 Other variations of this option include:

- a zonal postage-stamped charge based on the grouping of participants' grid exit points (**GXP**s) within geographic zones; and
- an Island-wide postage-stamped charge – effectively, this would treat each Island as a pricing zone.

Q 15.	Assuming there is a need for a locational element to transmission pricing, does the tilted postage stamp option provide a reasonable trade-off between signalling objectives and simplicity?

Option 3: Augmented nodal pricing signals

3.3.7 This augmented nodal price signals option was identified in the efficient pricing theory report[17] prepared by Frontier for the Commission. It seeks to directly address the deficiencies in nodal energy prices created by excessive or premature network investment. Under this regime:

---

[17] See Frontier Economics, *Theory of efficient pricing of electricity transmission services*, July 2009, available at http://www.electricitycommission.govt.nz/advisorygroups/pjtteam/tptg/meetings/28jul09/index.html

- transmission charges should be highest for those generators and loads that benefit most from excessive or premature network investment; and
- transmission charges should be lowest (or negative) for those generators and loads that are made most worse off from excessive or premature network investment.

3.3.8 Frontier has set out that, in order to develop this option further, it is necessary to investigate the extent to which current nodal prices diverge from those that would be provided by a theoretically optimal transmission grid. This could be considered in the following way.

3.3.9 The theoretically optimal transmission grid can be thought of as one where the financial value of losses and constraints earned across the grid matches the revenue required to fund the grid. At present, grid annual revenue requirements are at about $600 million, and loss and constraint revenues are between $40 million[18] and $200 million[19].

3.3.10 Three factors are expected to explain this difference and these are set out in the Frontier report and have been discussed earlier in this report. They are:

(a) economies of scale;

(b) 'over-caution' of network planners and regulators which leads to early investment or over-investment in transmission due to considerations of economic risk of late commissioning and the use of deterministic reliability investment criteria; and

(c) inaccurate pricing of supply security.

3.3.11 It is not clear whether these factors are material in New Zealand. The Commission is proposing to consider a method to observe the divergence from the theoretically optimal grid. This would use a model of scheduling, pricing and dispatch (SPD) and involve two iterative steps:

(a) Estimating the theoretically optimal grid in order to estimate the augmented nodal prices that could be used to allocate locational charges for transmission customers. The theoretically optimal grid could be approximated by using a model to reduce the size of the current transmission grid until the annual sum of loss and constraint rentals received is equal to the annual revenue requirement for the reduced set of transmission assets.

---

[18] Loss and constraint revenues for 2007.

[19] Loss and constraint revenues for 2008.

(b) Taking the current grid and simulating the expected distribution of nodal prices with a non-supply due to transmission priced at $20,000MWh (the value of unserved energy).[20]

3.3.12 While this modelling should result in estimation of the efficent nodal prices that could be used to compare with currently anticipated nodal prices and the difference used to design locational price signals, its weakness may be the complexity of the modelling required.

Q 16.	What are submitters' initial views on the economic merits of the augmented nodal pricing approach and are these likely to be outweighed by practical implementation considerations?

Option 4: Load flow-based approaches[21]

3.3.13 Load flow-based transmission pricing options involve a process of network analysis to attribute costs to participant connection points based on an identifying the network assets 'used' to convey electricity from points of injection to points of withdrawal. Load flow approaches can be based on the topology of the existing network as in Australia (**CRNP**) or on forward-looking network development costs, as in Great Britain (**ICRP**). In both Australia and Great Britain load flow approaches are used to recover a portion of the network costs.

3.3.14 A load flow approach to allocating shared network costs has previously been used in New Zealand, but was replaced with a postage stamp interconnection charge allocated by peak demand in 1999. The change addressed concerns over the complexity and variability of the recovery of the costs of interconnection assets[22].

3.3.15 With adjustments, load flow-based approaches can provide a reasonable proxy for the LRMC of network usage. The Frontier report outlines the type of adjustments that have been employed in two Australian states where CRNP approaches are used. These adjustments have been introduced to mitigate some perverse pricing outcomes that can occur where:

---

[20] This is the current value of unserved energy used by the Commission in its analysis, however this is under review.

[21] The term 'load-flow based approach' requires the use of network analysis..

[22] There is a brief overview of the load flow based methodology used previously in New Zealand, p 15, 16 of a report prepared for the Commission by Covec, *Locational signals for new investment*, August 2004. available at: http://www.electricitycommission.govt.nz/infopapers/index.html

(a) elements of the network are either lightly loaded and so charges may be high due to the high costs of the assets being used to serve the relevant loads; or

(b) elements or the network that are heavily-used and augmentation is imminent but charges may be low due to the low historical costs of the assets being used to serve the relevant loads.

3.3.16 Further, it is feasible that load flow-based approaches could achieve similar results to the tilted postage stamp approach from a sounder analytic base and without having to rely on the somewhat arbitrary geographic assumptions required for the tilted postage stamp approach.

Q 17.	Assuming there is a need for a locational element to transmission pricing, is load-flow modelling a reasonable basis for cost allocation?
Q 18.	If so, do you have a view on whether the CRNP, ICRP or an alternative methodology is preferable?

Q 19.	Are there any other high-level options that the Commission should consider?

3.4 Further issues

3.4.1 Separate from these high-level options, there are four other key issues arising in the consideration of transmission pricing methodology. These are:

- the approach to setting connection charges;
- the treatment of transmission alternatives;
- linking transmission pricing with service quality; and
- static reactive compensation.

3.4.2 These issues are discussed below.

(a) Treatment of connection costs

3.4.3 One option for changing existing connection charging arrangements is to introduce a ‘true’ deep connection charging regime (also known as a ‘but for’ approach), as in place in the Pennsylvania-New Jersey-Maryland (PJM) market in the United States. Under this approach, new connecting parties would be required to pay for system upgrades required to support their load or generation facility. For example, for a new generator to qualify as providing a capacity requirement[23], it would have to ensure that any transmission constraint limiting its contribution to the system peak demand was built out. In exchange, contributing parties would receive some form of transmission rights to help hedge the nodal pricing signals they face in settlement.

3.4.4 However, if such an option were to be pursued in New Zealand, a number of issues would need to be resolved or otherwise addressed. These include:

- the role of the GIT in approving transmission investment and the lack of a capacity market in New Zealand;
- the case where organic load or generation growth drives augmentations, rather than discrete new connections; and
- charging for sunk network assets paid for by an earlier-connecting party.

Q 20.	Is there merit in pursuing a PJM-style 'deep' connection option in the New Zealand market?

3.4.5 Compared to shared network costs, the allocation of dedicated connection costs is relatively straightforward because there are fewer externalities to consider. There has been some concern that connection assets (as defined in the existing TPM) may give rise to some difficulties primarily because of the scope for connection assets to be shared by two or more participants, either from the outset of commissioning or over time.

3.4.6 Two potential issues were raised by NERA in their paper for the New Zealand Electricity Industry Working Group[24]:

- 'Right-sizing' spur lines – if spur lines are classed as connection assets, there is a question as to how to ensure they will be built to a size capable of accommodating future expected connections.
- Cost allocation to subsequent connecting parties – participants will be deterred from seeking connection if subsequent connecting parties can 'free-ride' on their investment by connecting at only incremental cost.

3.4.7 TPTG members have questioned whether these issues were relevant to the New Zealand context.

---

[23] In the PJM market along with others in the US and unlike in New Zealand or Australia, retailers must have their sales obligations underwritten by contracted generation capacity.

[24] Nera Economic Consulting, *A Discussion Paper for the New Zealand Electricity Industry Work Group (Working Draft),* June 2009

3.4.8 There is a contestable market for connection services in New Zealand, and there are a range of transmission service providers active in this market.

3.4.9 The Commission notes that it is feasible that the contestable market for connection services provides the correct incentives on parties negotiating the contractual basis for these.

3.4.10 For example, in a contestable market for connection services:

- a connecting party could welcome the opportunity to share costs with later connecting parties;
- scale economies in transmission could encourage the provision of surplus capacity in deep connection assets when the parties involved could anticipate sharing with other parties; and,
- speculative investment in excess capacity could also be undertaken by entrepreneurs.

Given that there appears to be a functioning contestable market in the provision of connection assets, the current regulatory regime appears to be satisfactory.

Q 21.	Are there aspects of connection charging that should be reviewed? If so, please give arguments why.

(b) Treatment of transmission alternatives

3.4.11 An issue that often arises in transmission pricing is the treatment of transmission ‘alternatives’, such as local generation and demand-side management (**DSM**). Transmission alternatives also include grid-connected generation in relatively load-rich areas such as the north of the North and South Islands. These options are often considered in the GIT when new transmission projects are being assessed.

3.4.12 Frontier states that transmission alternatives should generally face similar transmission pricing signals to grid-connected loads and generators. This suggests that market interventions (such as Grid Support Contracts[25]) should not be required. However, Frontier also notes that it may be worth clarifying the treatment of distributed or local generation.

[25] Transpower has developed a Grid Support Contract (GSC) Product. GSCs are intended to enable Transpower to manage risks resulting from any construction delays, higher than forecast demand growth or major asset failure, and to defer some transmission investment. The scope includes consideration of all forms of non-transmission options including large and small generation and both aggregated and DSM

3.4.13 The Commission is considering the issue of transmission alternatives as part of this review, prompted by efficiency concerns and the evidence to date that there have been no specific transmission alternatives approved as alternatives to investment in interconnection assets since the Part F regime came into effect in 2005.

Q 22.	Is it necessary or worthwhile to alter or clarify the existing treatment of transmission alternatives?

(c) Service quality and pricing

3.4.14 One of the issues raised by some TPTG members and set out in the Strata report was the fact that the TPM does not link transmission prices paid by particular customers to the service levels they request or receive.

3.4.15 Members recognised that Transpower is subject to performance incentives through the Part 4 Commerce Act 1986 provisions in respect of its pricing and service, and is subject to liability for capped direct costs in the benchmark agreement and capped costs in respect of the interconnection rules. Under the current framework the TPM is a cost-allocation methodology allocating asset capital charges, asset maintenance and other costs.

3.4.16 However the Commission is considering whether there are mechanisms that could provide compensation for failure to meet an agreed service level.

3.4.17 The merits of a liability and compensation regime in respect of a failure to provide transmission services were considered during the finalisation of the benchmark agreement and interconnection rules in May 2007.

3.4.18 At the time, seven 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.

(f) No liability.

3.4.19 The Commission's decision was to favour option (a) – liability for direct costs with elements of (d) – suspension of grid charges. However, the Commission did advise that, after the benchmark agreement and interconnection rules were made, it proposed to review whether it was desirable or feasible to implement a USG.

3.4.20 At this time, the Commission could consider as part of its review of transmission pricing the two options that might require a change to the TPM[26]: either a USG or voluntary insurance.

3.4.21 A USG would require Transpower to pay compensation for an ex ante determined economic loss incurred by consumers in the event of an unplanned loss of supply arising from the failure of transmission assets. Compensation could be set based on a value of lost load of $20,000/MWh multiplied by the loss of consumption based on a comparison of actual consumption from the grid to historical consumption levels. As such, the scheme would encourage Transpower to manage its operational and maintenance decisions in order to minimise the volume of unserved energy.

3.4.22 Transpower would be able to recover a target level of compensation from its customers through regulated charges as an economic cost defined by the TPM. Transpower would have incentives to outperform the target in order to retain the revenue it was not required to pay out in a given year. The Commission expects that Transpower's annual exposure under a USG scheme would be capped.

3.4.23 Under a 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 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 grid exit point and the expected level of supply interruptions using a detailed regulated pricing methodology.

3.4.24 An efficient liability and compensation regime should incentivise efficient decision making by Transpower, transmission customers (load and generation connections) and end-users in respect of price/quality trade-offs.

Q 23. Should either a USG or a voluntary insurance scheme be considered within the review?

Q 24. Are there other options for linking service quality and pricing that you think the Commission should consider? If so, please give details.

[26] The other options are contractual solutions and as such do not require a change to the TPM and therefore are not being considered as part of the review.

(d) Static reactive compensation

3.4.25 One of the issues identified in previous work was whether voltage support charges – allocating the costs of Transpower's investments in static reactive power sources – could be included in the TPM. This was not considered in detail in the Frontier report, but the Commission has considered this issue in related work.

3.4.26 The Commission has been investigating changes to the current arrangements for reactive power investment. These investigations have been in response to a number of concerns electricity participants have that are expressed in relation to the Power Factor (PF) requirements in the Connection Code.

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

3.4.28 The Commission published an Issues Paper entitled *Options for ensuring efficient reactive power investment* on 26 September 2008 to explore options to address those concerns. The Paper did not propose any preferred solution and discussed the advantages and disadvantages of a number of alternative approaches to cost allocation or price discovery mechanisms for investment in reactive power.

3.4.29 Potentially the status quo option may not provide sufficient prescription to facilitate the allocation of costs to causers required as part of non-compliance agreements.

3.4.30 After considering submissions on the Issues Paper, the Commission has developed alternative approaches to allocating efficiently the costs of providing reactive power investment. One approach that was considered in the Issues Paper remains an option which is to have the TPM allocate the costs of new and existing static reactive power assets.

3.4.31 For new static reactive power investments the process would work as follows:

(a) Transpower identifies the need for static reactive power investments in its Annual Planning Report (**APR**) on a regional basis.

(b) Designated Transmission Customers (**DTC**s) in each region would then determine whether, instead of paying their proportionate cost of such investments, they would prefer to invest themselves. If so, they would confirm with Transpower that they would make such investment; the end result being that Transpower would no longer need to invest.

(c) If DTCs do not invest and Transpower does, the costs of that investment are allocated on the basis of the TPM.

3.4.32 For existing static reactive power assets the costs would also be allocated on the basis of the TPM.

Q 25.	Do you agree that the Commission should consider a methodology for allocating the costs of existing and new static reactive power assets as part of the review?

3.5 Filtering Criteria

3.5.1 As outlined in section 2.3, this review consists of three stages. At this first high-level options stage the focus is on locational cost allocation issues. Subsequent stages will consider pricing structure issues and will involve further analysis. This further analysis will include closer assessment of options against the pricing principles and cost-benefit analysis of short-listed options.

3.5.2 Frontier Economics has developed a number of criteria that could be used for narrowing down the high-level options outlined above in order to provide a short list of options and enable further assessment of options.

3.5.3 These criteria are focused on first identifying whether there is a case for further locational cost allocation in order to improve efficient investment in transmission and generation (Criterion 1, below).

3.5.4 Frontier's report gives a qualitative evaluation of the high-level options against each criterion.

Criterion 1 – Divergence from optimal transmission investment

3.5.5 As noted above and discussed in the Frontier report, full nodal pricing in the energy market ought to provide efficient signals to guide participants' investment decisions in generation and load projects, so long as investment in the transmission grid occurs optimally. Under these conditions, participants should receive pricing signals that provide them with incentives to make efficient decisions regarding the location, timing and technology of their investments. However, to the extent that actual transmission investment exceeds the perfectly efficient level of investment, nodal price differentials will be inappropriately 'muted' and participants' investment decisions will be distorted as a result. For example, early or excessive transmission investment could lead to generation investment taking place near existing energy sources rather than closer to load. These signals will be exacerbated if, as under the current market design, nodal prices do not signal the value of non-supply to consumers when load is shed.

3.5.6 This suggests that the greater the degree of theoretical ‘overbuilding’ in the transmission system, the stronger the case for a locational transmission pricing methodology to compensate for the muting effect on nodal price differentials. Therefore, one important filtering criterion is the observed degree (if any) of such network overbuilding.

Criterion 2 – Theoretical precision

3.5.7 Different locational pricing methodologies offer varying degrees of theoretical precision in terms of properly compensating for muted nodal pricing signals. Whilst theoretical precision is not the only or even the most important criterion for a TPM to fulfil, how close it is to sending ‘economically correct’ signals is relevant to the choice of methodology.

Criterion 3 – Locational hedging options

3.5.8 As part of its MDP, the Commission is currently considering several locational hedging options. These are set out in the Commission’s consultation paper, *Managing locational price risk: options*.

3.5.9 These include:

- Locational Rental Allocations (**LRA**s);
- Financial Transmission Rights (**FTR**s); and
- a hybrid of LRAs and FTRs.

3.5.10 That consultation paper also sets out zonal pricing as an option for managing locational price risk.

3.5.11 The development of locational hedging instruments will also influence the choice of a transmission pricing regime. Broadly speaking, to the extent that locational hedging instruments may have the effect of reducing nodal price nodal price signals, the transmission pricing regime will need to impose more locationally-differentiated charges.

Q 26.	If locational hedging instruments were introduced that had the effect of muting nodal price signals, do you consider that locational signals should be enhanced through transmission pricing?

Criterion 4 – Network topology

3.5.12 The discussion of the various high-level options indicated that network topology may also be a relevant consideration in narrowing the choice of options. In general, load flow approaches are better suited to large meshed networks, where the lumpiness of transmission investment is less likely to distort load flow based transmission charges away from LRMC than in the case of radial networks where simpler approaches could be adopted.

Criterion 5 – Information requirements/Implementation difficulty

3.5.13 More informationally-demanding approaches are likely to involve greater implementation difficulty. Load-flow approaches require significant modelling input. However, they have proven practicable in Australian and Great Britain. A postage stamp approach and its variations generally impose much less implementation difficulty than load flow approaches. An augmented nodal approach is likely to require substantial information and effort to develop and implement.

Criterion 6 – Governance arrangements

3.5.14 One relevant consideration to the selection of a TPM is the incentives it provides to participants with respect to transmission planning decision-making processes. Frontier states that at present, generators do not pay the interconnection charge and hence have little interest in contesting the GIT analysis of interconnected grid augmentations. Consumers do have an interest, but often lack the resources and knowledge to take part effectively. The allocation of transmission costs to particular classes of market participants will likely provide them with strong incentives to be involved in transmission planning and investment decisions. This may be desirable from the perspective of promoting close scrutiny of such decisions and may better support efficiency objectives.

Criterion 7 – Good regulatory practice

3.5.15 Good regulatory practice is an umbrella criterion that encompasses minimising subjectivity, promoting transparency and predictability of network tariffs. These features all contribute to the degree of confidence that participants can have in the integrity of the signals that the transmission pricing methodology provides.

Criterion 8 – Stakeholder acceptability

3.5.16 Stakeholders have diverse interests and commercial incentives, and stakeholder acceptability is unlikely to be universal. However, the relevance of stakeholder acceptability of a pricing regime derives from the likelihood that approaches that are unacceptable to a large proportion of participants will tend to be unstable and face pressures for revision over time.

Q 27.	Do you consider that the criteria outlined in this paper are appropriate criteria for filtering high-level options? Please outline your reasoning.
Q 28.	Are there other criteria that you consider might be appropriate?

4. Next steps

4.1.1 The Commission expects to undertake three analysis and consultation stages as part of this review of transmission pricing. The Commission strongly encourages interested parties to actively participate in the consultation process.

4.1.2 The first stage is completed with this consultation paper considering issues with current transmission pricing and high-level options. The second stage will be an analysis to identify a short list of options, and the third stage will be a detailed evaluation of a preferred option for transmission pricing (including assessing it against alternatives). At each stage the Commission expects to publish a consultation paper and undertake public consultation.

4.1.3 If the preferred option is a new approach to transmission pricing, the Commission will publish a rule 4 issues paper detailing the preferred option, a draft process for Transpower to follow and draft guidelines for Transpower to use in developing the new TPM. If the preferred option leads to significant changes in charges to participants, the review will consider options for transitional arrangements.

4.1.4 The Commission recognises that this consultation paper is at a very high-level and it deliberately does not consider detailed costs and benefits of the various options. The Commission will consider, and anticipates presenting, more detailed design of the short-listed options (including their costs and benefits in comparison with the status quo) in stage 2.

4.1.5 As part of the process of short listing options the Commission will:

(a) review submissions and publish a summary of submissions;

(b) hold a workshop to further consider issues arising from submissions or from further Commission work; and

(c) continue to seek specialist advice and review from the TPTG.

4.1.6 The Commission plans to publish a second consultation paper on short-listed options in mid-2010.

5. Summary of questions

Appendices

Appendix 1 Format for submissions

The Commission's preference is to receive submissions in electronic format. If possible, submissions should be provided in the following format.

Where you are responding yes or no to a question, please provide general comments in support of your response

Question No.	Question	Response	General comments in support of response

Appendix 2 Frontier Economics Identification of high-level options and filtering criteria.