Transmission Pricing Methodology: issues and proposal

Consultation Paper

10 October 2012

Executive summary

1. The Electricity Authority (Authority) is reviewing the transmission pricing methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover costs of providing transmission services.

2. The Authority considers that the current TPM can be improved so as to better promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

3. The Authority developed a decision-making an economic framework on which it would make decisions about the TPM, which was generally well received by submitters. The Authority has applied this framework[1] to derive its proposal for the TPM.

Market prices generally reflect differences in the cost of supply

4. Markets establish prices for goods and services through the interaction of buyers and sellers. A buyer will not pay more than a service is worth to them and a seller will not succeed in charging more than the value of the benefit to the buyer.

5. In highly competitive markets competition forces sellers to charge prices at levels reflecting the marginal cost of supply, and prices vary by location, date and time of delivery, and type of customer when the cost of supply is affected by those factors. Excluding the case where there are externalities (see below), these pricing outcomes are efficient and are widely accepted by buyers and sellers alike.

6. Even for less competitive markets, prices at different locations will vary, reflecting the potentially different costs of supply between locations. Prices may also vary by time and date of service, and type of customer where these factors affect the cost of supply.

Markets generally ensure parties benefiting from a service pay for those services

7. Prices in markets are often linked to the private benefits that different types of customers are likely to gain from a service when there is a high level of shared costs (often called common costs).

[1] Electricity Authority, May 2012, Decision-making and economic framework for transmission pricing methodology: decisions and reasons, available at, http://www.ea.govt.nz/document/16502/download/our-work/programmes/priority-projects/transmission-pricing-review/.

8. For example, entry prices to theme parks often differ substantially for local residents (who can visit often), for seniors (who may not get as much private benefits as others in the population), and for students and large families (who may be more budget-constrained than the general population). In each case prices are targeted roughly by the willingness of categories of consumers to pay for the service, and this practice is widely accepted by consumers.

9. In summary, markets result in parties that benefit from a service paying for that service, while parties that don't benefit don't pay. Payment is inextricably linked to parties benefiting from a service (called **beneficiaries** in this paper), to variations in the cost of supply and, in many situations, to the private benefits of consumers. One exception to this rule is when the production or consumption of a service has passive flow-on benefits or costs for other parties (called **externalities**).

The current TPM does not establish efficient prices

10. The current TPM comprises three main types of charges:

   a. a *connection charge*, to recover the cost to Transpower of connecting parties to the transmission grid;

   b. an *HVDC charge*, to recover the cost of the high voltage direct current (HVDC) link between the North and South Islands; and

   c. an *interconnection charge*, which in simple terms recovers the cost of the interconnected grid in each Island.

11. The connection charge is largely based on the commercial interaction of a connecting party and Transpower, but with regulated components to provide a backstop against deadlocked negotiations between a connecting party and Transpower. The Authority calls this a **market-like charge** because it closely resembles the market approach discussed above. The Authority considers that the connection charge is generally efficient but has identified some loopholes in the definition that, if addressed, would improve efficiency.

12. The Authority believes the current HVDC and interconnection charges are not efficient as the charges do not necessarily relate to the costs and benefits of HVDC and interconnection services.

13. In particular, many parties do not have strong incentives to ensure that transmission investment decisions only deliver the transmission service they want because they are not required to pay the full cost of the investment and service. This is because the costs may be borne by other parties who do not derive an equivalent private benefit.

14. The Authority considers that if transmission pricing promoted better targeted and better timed investment in transmission, generation and demand-side management, this would result in substantial efficiency gains.

Current HVDC and interconnection charges are inflexible and not durable

15. The HVDC and interconnection charges are the most contentious components of the TPM. The connection charge is generally not contentious as parties can readily verify the costs of supply and they accept they should pay for assets that directly benefit them. In contrast, the benefits of HVDC and interconnection services are indirect, the costs attributable to each user are hard to determine, and historically the methods used to recover those costs have not been closely linked to the benefits parties receive from them.

16. The Authority believes that parties generally accept charges when they can identify the link between the charges they pay, the cost of service to them and the benefits they receive. This clearly is not the case with the current HVDC and interconnection charges, which have been reviewed multiple times since 1994 and on which potentially affected parties have spent considerable time and resources lobbying and issuing legal challenges. The continuing potential for change does not promote efficient investment.

The party that benefits should pay

17. The proposal in this paper seeks to charge for HVDC and interconnection services in proportion to the private benefits that parties receive from those services. This is called a **beneficiaries-pay charge**.

18. The Authority's proposal allows those charges to shift over time with changes in grid use and configuration, without the need to fundamentally review the methodology. The Authority believes the flexibility of this approach, and the explicit link to private benefits, should create a durable approach to the TPM. This will reduce future costs associated with lobbying and legal challenges related to the TPM. It should also reduce the frequency with which the TPM needs to be reconsidered, thus providing efficiency benefits.

19. When a market-based charge is not possible and an administrative charge is necessary, a key principle is that "the party that benefits should pay." This principle is not new, or unique to New Zealand. A similar concept was developed by the Transport Working Group of the Electricity Governance Establishment Board in 2002. Case law from the United States of America has established that the Federal Energy Regulatory Commission (FERC) cannot approve a transmission pricing scheme that requires parties to pay for facilities from which they derive no benefits, or face charges where the benefits to them are trivial in relation to the costs sought.[2] FERC has adopted these principles in its order No. 1000, issued in July 2011, and recently confirmed them after considering submissions.

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2 Illinois Commerce Commission v FERC, 576 F.3d 470, 476 (7th Cir., citations omitted), available at, http://www.ferc.gov/legal/court-cases/opinions/2009/PT1FG750-opinion.pdf.

Surplus spot market funds are available to partially offset transmission charges

20. Access to the transmission system is currently rationed on a five-minute basis by the operation of the spot market. The scheduling, pricing and dispatch (SPD) model is used to dispatch generation resources for five-minute periods based on the half-hourly offer prices submitted by generators.

21. The SPD model dispatches generation by taking into account security constraints in the grid and estimated energy losses from transmitting electricity from grid injection points to grid exit points. The presence of losses and constraints results in spot price differences across the grid, and produces funds (referred to as **loss and constraint excess**[3]) that the clearing manager transfers to Transpower.

22. In effect the spot market already provides a **market approach** to paying for transmission services. Currently, Transpower pays the rentals to its transmission customers proportional to their transmission charges. In the customer's hands, the loss and constraint rentals have the effect of reducing the net amount the customers pay to Transpower.

23. In principle, loss and constraint rentals could fully fund HVDC and interconnection services. In practice a large funding deficit (or residual) occurs because grid investments typically exhibit large economies of scale, which results in significant spare capacity. In the short term, this spare capacity means there are few constraints and price differences across transmission lines are small. As a result, a transmission investor cannot rely on loss and constraint rentals to recover the costs of an investment to remove a constraint. Even without economies of scale issues, a large residual occurs if grid investments are made earlier than when they are justified on economic grounds.

The beneficiaries-pay charge may also leave a residual … to be covered by a residual charge

24. For similar reasons the revenue from the beneficiaries-pays charge is unlikely to fully cover the large deficit left after the loss and constraint excess is applied. Hence a second deficit occurs, which the Authority is proposing to cover with a residual charge.

25. The residual charge will be set to ensure Transpower's full economic costs are recovered from transmission customers.

26. A residual or "postage stamp" charge is essentially analogous to a tax or levy because there is no direct relationship between the amount paid, the cost of supply for individual components and the benefit grid users derive from them. The Authority thinks that a residual charging approach is inefficient and, in light of

[3] The loss and constraint excess is also referred to as loss and constraint rentals and "transmission rentals".

that, has a preference for funding transmission costs from transmission rentals and from the beneficiaries-pay charge. The Authority proposes that the residual charge should be levied on both demand (using regional coincident peak demand, or RCPD) and generators (using regional coincident peak injections, or RCPI), with 50% of the cost on demand and 50% on generation. The charge would be designed to encourage efficient avoidance of peak regional use of the grid. The Authority considers that the residual charge should be applied to generators, direct-connect customers and distributors (or retailers).

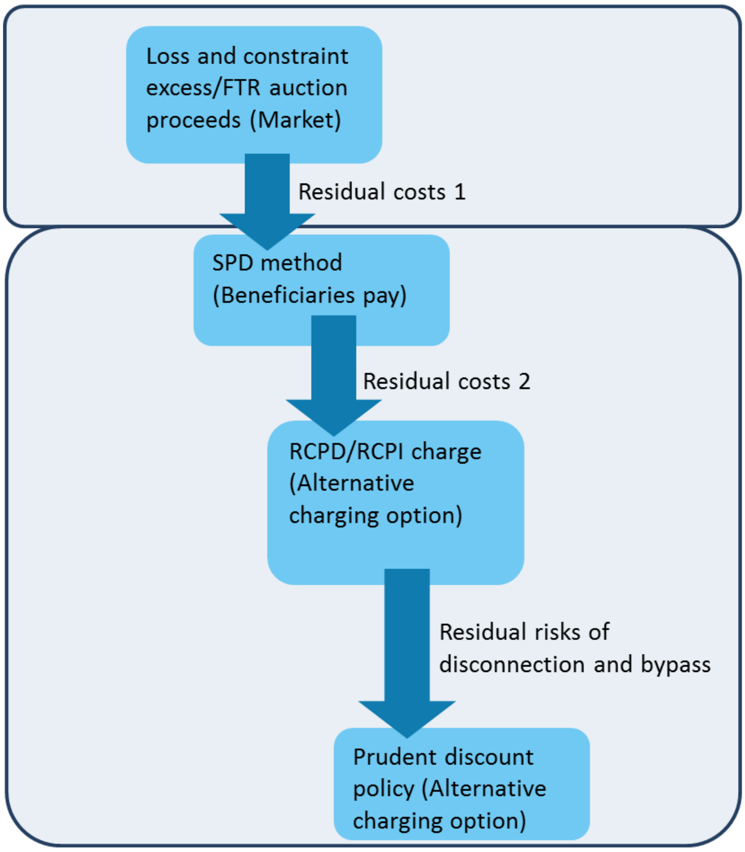
No transmission charge is perfect

27. The charging regimes proposed by the Authority, as with most transmission charging regimes, could result in a party inefficiently bypassing the grid (by investing in a transmission alternative) or inefficiently disconnecting from the grid.

28. The Authority is proposing to refine the current prudent discount policy, which provides Transpower with the ability to effectively set transmission charges for specific customers at the cost of the bypass investment when such investments are likely to occur.

29. The Authority's proposals in relation to HVDC and interconnection, together with an explanation of how each element relates to the Authority's economic framework for the TPM, is set out in Figure 1.

Figure 1: Overview of HVDC and interconnection proposal and relationship to economic framework



Methods for applying beneficiaries-pay charges

30. The key issue for the beneficiaries-pay charge is deciding what method to use to identify the beneficiaries of a transmission asset and to determine their private benefit from the asset.

31. There are diverse methods for identifying the benefit derived by parties from transmission services, ranging from rough approximations to sophisticated economic models.

32. The Authority considers that wholesale electricity market outcomes, assessed using the SPD model,[4] provide the best available method for implementing the beneficiaries-pays charge. The beneficiaries identified by this method would be charged for the cost of each investment in proportion to their share of the private benefits from each investment, but with their maximum charge not exceeding their private benefit in each case.

[4] Alternatively, the vectorised SPD (vSPD) model developed by the Authority could be used for this assessment. Accordingly, where this executive summary refers to SPD this should be read as “SPD or vSPD”.

33. The beneficiaries-pay charge would apply to the parties identified as benefiting from the transmission assets through wholesale market outcomes, as determined by the SPD model. Accordingly, the charge would apply to all parties offering to or purchasing from the wholesale market. The Authority proposes that the charge would be calculated each trading period and charged on a monthly basis.[5]

34. The Authority proposes to apply a cut-off date before which the beneficiaries-pay charge would not apply to existing transmission assets. The Authority proposes the cut-off date be 28 May 2004, the date on which the Electricity Commission first began approving transmission investments. The one exception to this is pole 2 of the HVDC link, which the Authority considers should also be subject to beneficiaries pay so that the charging basis for pole 2 is broadly consistent with the basis for pole 3.

35. The Authority proposes an investment cost threshold for application of the SPD method of $2 million. It is proposed that this threshold would apply for any assets added to Transpower's regulated asset base after 28 May 2004. The cost would be assessed as at the time the assets are added. The threshold is set so that the benefit derived from identifiable interconnection assets is attributed to beneficiaries by applying the SPD method. The costs of interconnection assets not covered by the beneficiaries-pay charge (i.e. assets built before 28 May 2004 (but not replacements or refurbishment of these assets) or since 28 May 2004 but with a cost below $2 million) would be recovered through the residual charge. HVDC and interconnection costs would also be recovered through a residual charge.

The SPD method should provide reasonable estimates of private benefits

36. The Authority's view is that it is not possible to design a perfect beneficiaries-pay charge with current technology, and it is not attempting to do so. The key issue for the Authority is whether the proposed beneficiaries-pay charge delivers greater economic benefits for consumers than any other practical alternative available to it. All transmission pricing options involve approximations and compromises, and the SPD method to implementing beneficiaries pay is no different in that regard.

The SPD method brings transparency to investment decision-making

37. The Authority believes generators – and consumers once dispatchable demand is introduced – will try to structure their offers to the spot market to reduce the estimation of their private benefits from specific grid assets.

[5] The Authority is currently reviewing the settlement and prudential arrangements for the wholesale market. If the outcome of this review was more frequent settlement the Authority would consider whether more frequent charging was appropriate for the TPM.

38. For example, South Island generators could avoid the beneficiaries-pay charge for pole 3 of the HVDC by offering on the basis of pole 2 alone being available. Rather than being a problem, the Authority believes this is a positive attribute of the proposal, viz:

a. If successful, the revised offering behaviour would reveal that pole 3 was not economically justified and doesn't deliver private benefits to South Island generators. The costs of pole 3 in this case should be recovered from consumers receiving private benefits from pole 3 (if any) or through the residual charge in a way that is analogous to a 'broad base low rate' tax on generators and consumers for uneconomic grid investments; and

b. Alternatively, if South Island generators were unable to structure their offers to avoid the beneficiaries-pay charge, this suggests pole 3 delivers private benefits to them, and that they should pay for (a portion of) the costs of pole 3, up to an amount not exceeding their private benefit.

The SPD method provides a highly flexible and durable beneficiaries-pay charge

39. Another key advantage of using the SPD model is that the beneficiaries-pay charge would vary in accordance with variations in the benefits each party receives.

40. For example, if there is significant electricity demand growth in the North Island requiring increased South Island generation, South Island generators would receive larger benefits from pole 3 on the HVDC link. Under the SPD method, as proposed in this paper by the Authority, South Island generators would automatically pay a larger share of the costs of pole 3. Similarly, any additional transmission investment required in the South Island to get the surplus power to the North Island would automatically be paid by South Island generators benefiting from those investments.

41. This flexibility should greatly reduce the need to fundamentally review the TPM in the future, bringing lower regulatory costs in the form of reduced lobbying activity and legal challenges, lower administrative costs associated with on-going reviews of the TPM and reduced regulatory uncertainty for investors, including transmission customers.

42. Where an investment has been made under the limb of the grid investment test that applied to investments required to meet the deterministic limb of the grid reliability standards, to the extent that the SPD method does not identify that investment as giving rise to private benefits, the costs of the investment would be paid through the residual charge. That is, the investment may achieve "uneconomic" levels of reliability, but was nevertheless required to ensure that the relevant deterministic grid reliability standard was met. In practice, however,

the SPD method should capture as private benefits most, if not all, improvements in transmission investment attributable to reliability. This is because an improvement in reliability will be manifested in sharply lower prices and increased quantities of delivered electricity than would have been the case without the investment. These effects also give rise to private benefits that will be measured using the SPD method.

Recovering the cost of connection services

43. The Authority considers that the arrangements for obtaining and providing connection services generally operate effectively and promote efficient investment in the electricity industry.

44. However, there are aspects of the connection charging arrangements that provide connecting parties inefficient incentives to minimise their connection costs by shifting some connection costs into the interconnection charge. These problems reflect relatively minor drafting deficiencies (loopholes) in the current TPM.

45. The Authority therefore proposes that the TPM should be amended to remove the identified loopholes. This approach would retain and improve the market-like arrangements for connection services.

Recovering the cost of network reactive support services

46. The Authority considers an exception to the principle that “the party that benefits should pay” arises when determining charges to recover the costs resulting from an externality. The Authority considers that the need to invest in static reactive support equipment is the result of an externality, which arises because parties are using power in a manner that results in a poor power factor for other transmission users.

47. The Authority proposes to apply a kvar charge to reactive power draw and to apply a requirement for a minimum power factor of 0.95 lagging. This provides parties with incentives to draw reactive power only where it is efficient to do so, or otherwise invest in equipment to manage their reactive power use.

48. The provision of **dynamic reactive support** is to make the grid more robust to contingent events that cause voltage instability (an externality) and to enable greater power transfer into a region. It is unlikely to be practicable, however, to charge the exacerbators of dynamic reactive support but it may be appropriate to charge beneficiaries of the greater power transfer it enables.

49. The Authority therefore proposes to charge for the costs of dynamic reactive support assets provided by Transpower using the beneficiaries-pay charge proposed for HVDC and interconnection.

Results of cost-benefit analysis

50. The Authority estimates that the overall TPM proposal would deliver net economic benefits of $173.2 million (net present value over a 30-year period) compared to the current TPM.

Table 1: Summary of aggregate costs and benefits (central case)

PV of economic costs and benefits	Authority proposal
Economic costs	$50.1m
Economic benefits	$223.3m
Net economic benefit	$173.2m

51. The breakdown of the net economic benefits for each component of the EA proposal is shown below.

Table 2: Breakdown of aggregate net economic benefits by transmission service (central case)

Net economic benefits (PV)	Authority proposal
Interconnection - HVDC	$158.2m
Reactive support	$13.0m
Connection	$2.0m
Total	$173.2m

The costs of implementing and operating the Authority's proposal relate to designing, implementing and operating the SPD method. This is expected to cost $5.6 million to design and implement, with on-going operating costs of $3.5m per year (in current dollars). Over a 30-year timeframe, these operating costs are estimated to have a present value of $44.5 million.

Assessment against the Authority's objective for the TPM

52. Overall, the Authority considers that its proposal achieves its objective for the TPM of facilitating efficient investment in the electricity industry and efficient operation of the transmission grid, generation (including distributed generation), distribution grids and demand-side management.

The full TPM proposal

53. The Authority's proposal for the TPM is detailed in chapter 5, and alternative options considered by the Authority are summarised in chapter 6. Draft guidelines for Transpower to develop the proposed TPM are set out in chapter 7 while a proposed process for Transpower to follow in developing the TPM is set out in chapter 8.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
AOPOs	Asset Owner Performance Obligations
Authority	Electricity Authority
AC	Alternating Current
ACC	AC Connection assets
ACI	AC Interconnection assets / Asset Concentration Index
AP	Average Participation
Capex IM	Capital Expenditure Input Methodology
CAPs	Code Amendment Principles
CEO Forum	Chief Executive Officer Forum
Code	Electricity Industry Participation Code 2010
DC	Direct Current
DTC	Designated Transmission Customer (referred to in this paper as transmission customers)
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right
GEM	Generation Expansion Model
GWh	Gigawatt hours
GST	Goods and Services Tax
HAMI	Historical Anytime Maximum Demand
HVDC	High Voltage Direct Current
IR	Instantaneous Reserve
Kvar	Kilo volt-ampere reactive (a measure of reactive power in an AC system)
LCE	Loss and Contraints Excess
LNI	Lower North Island transmission region
LRAs	Locational Rental Allocation
LRMC	Long Run Marginal Cost
LSI	Lower South Island transmission region
MAR	Maximum allowable revenue

Mvar	Mega volt-ampere reactive (a measure of reactive power in an AC system)
MW	Megawatt
MWh	Megawatt hours
NAaN	North Auckland and Northland project
NPV	Net Present Value
NRS	Network Reactive Support
NYISO	New York Independent System Operator
NZIER	New Zealand Institute of Economic Research
PDP	Prudent Discount Policy
RCPD	Regional Coincident Peak Demand
RCPI	Regional Coincident Peak Injection
Regulations	Electricity Industry (Enforcement) Regulations 2010
SFT	Simultaneous Feasibility Test
SPD	Scheduling, Pricing and Dispatch
SRC	Static Reactive Compensation
SVC	Static Var Compensator
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
TPTG	Transmission Pricing Technical Group
Transpower	Transpower New Zealand Limited
TWG	Transport Working Group
UNI	Upper North Island transmission region
US	United States
USI	Upper South Island transmission region
UTS	Undesirable Trading Situation
vSPD	vectorised Scheduling, Pricing and Dispatch

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1. Introduction

1.1 Background

1.1.1 The Electricity Authority (Authority) is reviewing the arrangements for determining the transmission pricing methodology (TPM), which specifies the method for allocating the costs of operating, maintaining, upgrading and extending the transmission grid.

1.1.2 The grid delivers electricity produced by grid-connected generators to locations where electricity is consumed or distributed onwards to end consumers. Transpower New Zealand Limited (Transpower) owns and operates the grid.

1.1.3 The current TPM is set out in the Electricity Industry Participation Code 2010 (Code),[6] which is administered by the Authority. The current TPM came into force on 1 April 2008, as part of the Electricity Governance Rules 2003.

1.1.4 The Authority has identified a number of changes affecting the electricity market and grid since the TPM came into force that represent a material change of circumstances.[7] Key changes are the establishment of a new regulatory regime in 2010 (including the establishment of the Authority), Transpower's significant capital expenditure programme (around $4 billion for the period 2010/11 to 2015/16[8]) and advances in computing capabilities.

1.1.5 The Authority is reviewing the TPM (the TPM review) and considers that the current TPM can be improved so as to better promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.[9]

1.1.6 The TPM determines how the costs of all transmission assets and services are allocated, except those assets and services subject to investment contracts under clauses 12.70 and 12.71 of the Code and existing new investment contracts and certain other contracts of the kind referred to in clause 12.95 of the Code.

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6 Schedule 12.4 of the Code.

7 Clause 12.86 of the Code.

8 Transpower, business plan capex forecast.

9 This is the Authority's statutory objective, prescribed in section 15 of the Electricity Industry Act 2010.

1.1.7 The Authority is consulting on the nature and materiality of the problems with the current TPM and is seeking views on a preferred option for a new TPM. The Authority is also consulting on the process for the development and approval of the TPM and the guidelines to be followed by Transpower in preparing a methodology for allocating its revenues for the Authority's consideration.[10]

1.2 Purpose of this paper

1.2.1 This paper is an issues paper that sets out the process for development and approval of a TPM, and draft guidelines to be followed by Transpower in preparing a new TPM.[11]

1.2.2 The purpose of this paper is to seek feedback from consumers, industry participants and other interested parties about:

(a) the Authority's assessment of the nature and materiality of the problems with the current TPM (chapter 4);

(b) the Authority's preferred option for a new TPM (chapter 5);

(c) the alternative options identified and considered by the Authority for changing the TPM the Authority's preferred option for a new TPM (chapter 6);

(d) the proposed guidelines to be followed by Transpower in preparing a methodology for allocating Transpower's revenues to transmission customers (chapter 7); and

(e) the proposed process for development and approval of the TPM (chapter 8).

1.2.3 This paper does not propose amendments to the Code. Proposals to amend the Code will be consulted on during the subsequent process for the development and approval of a new TPM (if the TPM is to be revised).

Submissions

1.2.4 The Authority's preference is to receive submissions in electronic format (Microsoft Word). If possible, submissions should be provided in the format shown in Appendix A. It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to

[10] Clause 12.81 of the Code.

[11] Clause 12.81 of the Code.

submissions@ea.govt.nz with 'Consultation Paper—Transmission Pricing Methodology: issues and proposal' in the subject line.

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

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

Fax: 0-4-460 8879

1.2.6 Submissions should be received by 5pm on Friday, 30 November 2012. Please note that late submissions are unlikely to be considered.

1.2.7 The Authority invites interested parties to make cross-submissions, and these should be received by 5pm on Friday, 21 December 2012. Please note that late cross-submissions are unlikely to be considered.

1.2.8 The Authority will acknowledge receipt of all submissions and cross-submissions. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

1.2.9 Your submission will be made available publically on the Authority's website. Submitters should indicate any documents attached, in support of their submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

1.3 Next steps

1.3.1 The next steps are as follows:

(a) the Authority will hold regional forums to facilitate discussion of the matters raised in this paper;

(b) the Authority will publish submissions to this paper on Monday, 3 December 2012 and will provide until Friday, 21 December 2012 for interested parties to make cross-submissions; and

(c) the Authority will consider the comments about the proposed process and guidelines to be followed by Transpower and make any necessary changes, before finalising and publishing the guidelines and proposed process.

1.3.2 A more detailed draft process for the development and approval of the TPM is set out in chapter eight of this paper.

2. Context to transmission pricing

Key points

The purpose of the TPM is to ensure that the full economic costs of Transpower's transmission services are recovered from transmission customers in a way that promotes competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The TPM has evolved through several iterations since 1992, with change driven by changes to the electricity industry structure, development of electricity markets and advances in technology.

The Electricity Authority is responsible for approving the TPM (which is part of the Code) which determines the allocation of charges to transmission customers. The Commerce Commission is responsible for setting the total revenue recovered through the TPM.

Transmission costs are increasing due to Transpower's significant capital expenditure programme, which includes projects to replace high voltage direct current assets and augment the interconnection grid. The annual revenue that Transpower will receive is expected to increase by 79 per cent over the coming decade, from $624 million in 2010/11 to $1.1 billion in 2019/20.

The Authority considers there has been a material change in circumstances since the current TPM came into force in 2008: the establishment of a new regulatory regime in 2010; Transpower's significant capital expenditure programme; and advances in computing capabilities.

Subpart 4 of Part 12 of the Code provides a process for the development of the TPM, including reviews of the TPM.

2.1 Background

2.1.1 The purpose of the TPM is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs[12] of Transpower's transmission services are allocated so as to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.[13]

2.1.2 The costs of transmission services derive from operating, maintaining, upgrading and extending the transmission grid, which comprises over 41,000 towers and poles, 174 substations and over 11,800 km of transmission lines stretching from Kaikohe at the top of the North Island to Tiwai at the bottom of the South Island. The North Island and the South

[12] The current TPM describes full economic costs including costs relating to investments which are not subject to approval by the Commerce Commission under section 54R of the Commerce Act 1986, and costs to which the input methodology under section 54S of the Commerce Act applies.

[13] Clause 12.78 of the Code.

Island are linked by the 610 km high voltage direct current (HVDC) line between Haywards in the Hutt Valley and Benmore in the Waitaki Valley.

2.1.3 Transmission charges ultimately flow through the electricity supply chain to end consumers of electricity. Generators are generally able to factor the transmission charges they pay into the price at which they sell electricity.[14] Distributors pass the transmission charges they pay through to retailers via their distribution charges. Retailers re-price a range of input costs, including transmission charges passed through by distributors, and typically provide end-consumers with a price-bundled, delivered electricity retail service. In a few cases, some distributors pass transmission charges directly through to end consumers.[15]

2.1.4 As the previous paragraph suggests, parties in the supply chain do not bear much of the cost risks of transmission as these are generally passed on to consumers. This means that 'transmission customers' do not have a strong incentive to negotiate charges with Transpower or make price/reliability trade-off decisions. As a result, transmission customers have a tendency to seek high reliability in transmission assets because this lessens their risks but they do not bear the related costs.

2.1.5 The pattern of pass-through of transmission charges also means that price signals incorporated in the charges, such as avoiding peak-use, tend to get lost or smoothed for end consumers who do not directly face transmission charges.

2.1.6 The TPM has evolved through several iterations since Transpower's revenues were unbundled from the former Electricity Corporation's electricity bulk supply revenues in 1992. An overview of the evolution of the TPM since 1988 is provided in Appendix B.

2.1.7 The evolution of the TPM has been driven by factors such as changes to the electricity industry structure, development of electricity markets and technology advances. Additionally, allocating the costs of transmission has proved to be a controversial issue in New Zealand and internationally. There have been regular calls in New Zealand to alter the allocation of transmission costs; industry participants have at times legally challenged

[14] Note that a generator may not necessarily be able to price the electricity they produce to recover the total costs they incur or charges they face, because their competitors may not face the same, or same level of, charge.

[15] A distributor using the conveyance contracting approach will pass transmission charges directly on to end-consumers.

not only the process for developing the TPM but also the allocation methodology.[16]

2.1.8 The main reasons why transmission cost allocation and pricing are controversial are:

(a) the costs involved are considerable, in particular the potential magnitude of charges for individual parties;

(b) the cost allocation and the charges do not reflect who benefits and what benefit they receive from transmission assets;

(c) there have been difficulties defining the service and excluding parties from using those services as well as difficulties determining the marginal costs of additional use. This has led to difficulties setting prices that reflect the marginal cost of use;

(d) there have been difficulties identifying and verifying the parties that derive a benefit from the shared transmission system or the extent to which they benefit. This means that, historically, costs have not been allocated in accordance with the share of benefits;

(e) changes invariably create winners and losers as costs are reallocated between the parties that pay for transmission services. Consequently, parties have an interest in seeking a favourable cost allocation. For example, the 1996 decision that required South Island generators to pay the costs of the HVDC link is a key point of contention in the debate about the TPM; and

(f) there has been on-going debate internationally about the economically efficient allocation of transmission costs. This encourages parties to challenge the validity of one approach over another depending on how an approach affects their allocation of costs.

2.2 Role of the TPM within the regulatory framework for transmission services

Commerce Act regulation of transmission services

2.2.1 The Commerce Commission applies price-quality regulation to the transmission services provided by Transpower under Part 4 of the

[16] For example, refer High Court of New Zealand, 29 August 2005, Contact Energy Limited and Meridian Energy Limited v Electricity Commission and Transpower New Zealand Limited, CIV-2005-485-624, MacKenzie J.

Commerce Act 1986.[17] This process sets the maximum allowable revenue that Transpower can recover, as well as setting minimum quality standards, for a five-year regulatory period. Transpower's maximum allowable revenue is determined using a 'building block approach', which involves identifying the costs of operating, maintaining, upgrading and extending the transmission grid.[18]

2.2.2 Under individual price-quality regulation, the total revenue that Transpower can recover from users of the transmission grid is capped.[19] For example, the maximum allowable revenue for the remainder of the current regulatory period is:

(a) $783.8 million for the pricing year from 1 April 2012 to 31 March 2013;

(b) $906.4 million for the pricing year from 1 April 2013 to 31 March 2014; and

(c) $958.9 million for the pricing year from 1 April 2014 to 31 March 2015.

2.2.3 Currently, total annual regulated transmission costs make up around 7.4 per cent of a typical household consumer's electricity bill.[20] Transpower projects its maximum allowable revenue to rise to approximately $1.1 billion by 2019/2020. However, Transpower consider that even with these investment costs transmission costs will not make up more than 10% of a typical household consumer's electricity bill.[21]

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17 Transpower is the only provider of transmission services in New Zealand – transmission grids are typically a natural monopoly because high fixed costs make it uneconomic to develop a second and competing grid in a particular market or location.

18 More information about the role of the Commerce Commission and individual price-quality regulation for Transpower is available at http://www.comcom.govt.nz/price-quality-regulation-that-applies-to-transpower/.

19 Commerce Commission, Commerce Act (Transpower individual price-quality path determination 2010), as amended 31 January 2012, http://www.comcom.govt.nz/assets/Electricity/Transmission/Transpower-Amendment-to-Path-Determination-January-2012/Transpower-Individual-Price-Quality-Path-Determination-2010-Consolidated-January-2012.pdf.

20 Electricity Authority, Factsheet: Breakdown of a typical bill, available at, http://www.ea.govt.nz/document/16850/download/consumer/factsheets/.

21 https://www.transpower.co.nz/about-us/what-we-do/frequently-asked-questions.

TPM recovers the costs of transmission services from designated transmission customers

2.2.4 The Commerce Commission determines the size of the revenue pie recoverable by Transpower in a year. The role of the TPM is to determine how the revenue pie is sliced and allocated between parties.

2.2.5 Each “designated transmission customer” (referred to in this paper as a “transmission customer”) and Transpower are required, under Part 12 of the Code, to enter into a transmission agreement. The Code defines transmission customers as (a) direct consumers that have a point of connection to the grid, (b) distributors and (c) generators that are directly connected to the grid.[22] An Authority-approved benchmark agreement effectively provides a default transmission agreement where Transpower and a transmission customer are unable to agree a transmission agreement.

2.2.6 The transmission agreement provides the basis for paying transmission services charges determined in accordance with the TPM. The TPM requires Transpower to determine annually each “pricing year” (1 April to 31 March) the allocation of transmission charges amongst transmission customers that will recover its maximum allowable revenue for that year.

2.2.7 The current TPM has applied since 1 April 2008. The TPM recovers the costs of transmission services, which include capital, maintenance, operating, overhead costs and costs incurred by Transpower in relation to approved investments and is described in Figure 2.[23] However, the TPM does not recover the economic costs associated with:

(a) investment contracts between Transpower and connection parties allowed under clauses 12.70, 12.71 and 12.95 of the Code;

(b) a number of specific notional embedding contracts and fixed-term input connection contracts agreed under TPMs that applied prior to 2008;

(c) Transpower’s non-regulated activities (for example, costs associated with its subsidiary businesses); and

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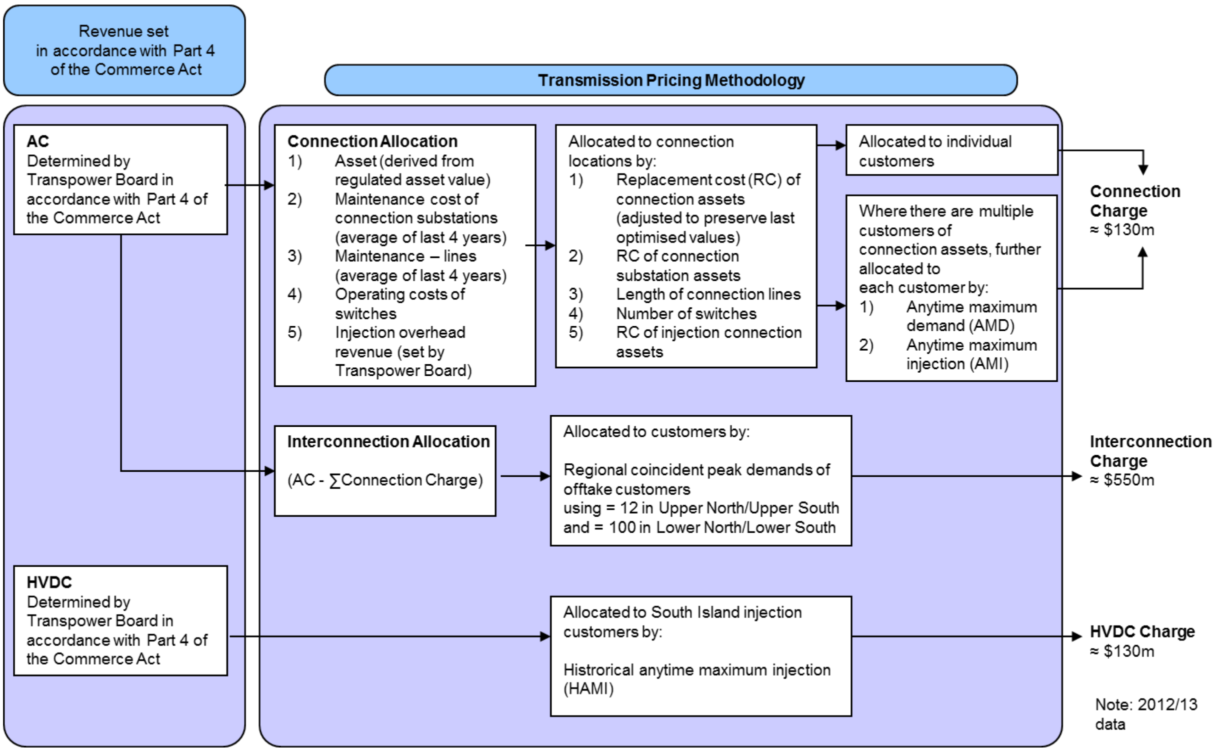
22 Schedule 12.1 of the Code.

23 The Code defines approved investments as (in summary) an investment approved under section III of part F of the former Electricity Governance Rules 2003 (whether by the Electricity Commission, prior to 1 November 2010, or by the Commerce Commission between 1 November 2010 and 31 January 2012), or an investment permitted under the Capex IM.

(d) Transpower performing the system operator role for the transmission grid.

Figure 2: Transmission Pricing Methodology overview



Source: Schedule 12.4 of the Code.

2.2.8 The key elements of the TPM are:

(a) a *connection charge* that recovers the costs of dedicated alternating current assets connecting a distributor, grid-connected major user and/or generator to the transmission grid.[24] Connection charges amount to about $129 million for the 2012/13 year;

(b) an *HVDC charge* that recovers the costs of the HVDC link between the North Island and the South Island. This charge is paid by South Island generators based on their share of peak injections in the South Island – called historical anytime maximum injection (HAMI).[25] HVDC charges amount to $129 million for the 2012/13 year; and

[24] In most cases connection assets are used by a single transmission customer, but there are some cases where two or more transmission customers share connection assets. The TPM allocates the connection charge for shared connection assets in proportion to each transmission customer's share of maximum injection or demand.

[25] HAMI for a customer at a South Island generation connection location means either the average of the 12 highest injections at that South Island generation connection location during the capacity measurement period for the relevant pricing year; or the average of the 12 highest injections at that South Island generation

(c) an *interconnection charge* that recovers the costs of interconnection assets and a proportion of overhead and corporate costs. This charge is paid by distributors and grid-connected major users. The interconnection charge is based on contribution to regional coincident peak demand (RCPD).[26] Interconnection charges amount to $547 million for the 2012/13 year (an increase of $100 million over the previous year which is expected to further increase over the next few years as a result of grid investments planned by Transpower).

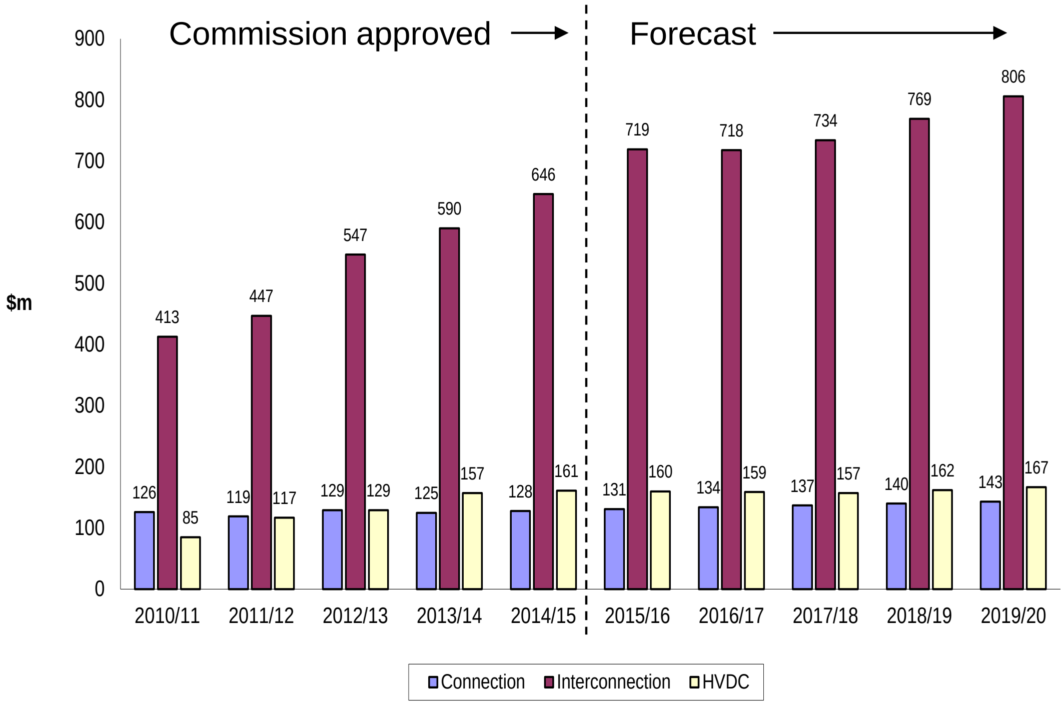
2.2.9 The current TPM also includes a prudent discount policy (PDP). The purpose of the PDP is to discount transmission charges to avoid uneconomic bypass of existing grid assets. The PDP does this by discounting the charges for a party who would otherwise not connect to the transmission grid or would disconnect from the grid. The costs of agreed prudent discounts are recovered from other transmission customers in accordance with the TPM. Only two prudent discount agreements have been made since the current TPM was implemented in 2008. Prior to 2008, a number of notional embedding agreements, the precursor to prudent discount agreements, were signed and several of these are still operative.

2.2.10 Figure 3 shows a breakdown of the actual and forecast revenue for Transpower for the period from 2010/11 to 2019/20.

connection location during any of the four immediately preceding pricing years, whichever is highest. Refer clause 3, schedule 12.4 of the Code.

26 Regional coincident peak demand (RCPD) for a customer at a connection location means the customer's off-take at that connection location during a regional peak demand period. Refer clause 3, Schedule 12.4 of the Code.

Figure 3: Actual and forecast revenues recovered by transmission charges 2010/11 to 2019/2020[27]



2.2.11 The interconnection charge is expected to increase by around 95% over the period 2010/11 to 2019/20 as a result of new investment in interconnection assets.

The transmission investment approval process

2.2.12 Transpower's investments in the transmission grid are regulated by the Commerce Commission under Part 4 of the Commerce Act 1986. For that purpose, the Commerce Commission has determined the Capital Expenditure Input Methodology (Capex IM) for Transpower.[28]

2.2.13 The Capex IM applies to all capital expenditure that is intended to enter Transpower's regulated asset base.[29] Capital expenditure is categorised as either "base capex" or "major capex" and the Capex IM includes different processes for the approval of base capex and major capex projects.

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[27] Source: Transpower.

[28] *Re Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC2.

[29] Regulated asset values form part of the building block calculation of Transpower's maximum allowable revenues by the Commerce Commission.

2.2.14 Major capex involves expenditure on a project of more than $1.5 million[30], or included in a programme of over $5 million that are needed to meet grid reliability standards or that reduce costs in the power system, for example, to reduce energy losses or dispatch constraints. Major capex also includes non-transmission solutions. The Commission decided on the $5 million threshold based on independent advice that $5 million was an appropriate materiality threshold for expenditure substitution. The $5 million threshold will increase to $20 million from 1 April 2015. Base capex includes all other capital expenditure; in particular, base capex includes capital expenditure on asset replacement and refurbishment, business support, and information system and technology assets.

2.2.15 An approval enables Transpower to include the project cost in its regulated asset base and recover those costs as a component of its maximum allowable revenue.

2.2.16 Transpower is required to submit a base capex proposal at the start of each five-year regulatory period, detailing project investment in base-case projects over the upcoming five years. Following assessment, a base capex allowance is set by the Commerce Commission. Once the allowance is set, it is up to Transpower to decide how much investment it actually undertakes. Over- or under-expenditure of the allowance is dealt with via a mechanism in the Capex IM that provides incentives on Transpower to achieve cost efficiency gains and to deliver the agreed level of outputs.

2.2.17 In contrast, major capex proposals may be submitted to the Commerce Commission at any time and are consulted on, assessed, and declined or approved. The investment test (seeks to ensure that only the investments with the highest expected net electricity market benefit are approved. Components of an approved project (including the maximum recoverable cost) can be amended after the project has been approved.

2.2.18 Under the investment approval regime, there is no ability for the transmission customers that pay the cost of interconnection or HVDC investments via the TPM to choose whether the investment will proceed, or when, or according to what design. However, opportunities exist for transmission customers to participate during the investment proposal and approvals process. In particular, transmission customers can make submissions to Transpower or the Commerce commission, or both, as provided for in the capex IM.

[30] This threshold will increase to $5 million from 1 April 2013 and then to $20 million from 1 April 2015.

2.3 The review of the TPM

2.3.1 The Authority's predecessor, the Electricity Commission, initiated a review of the TPM in April 2009. The Electricity Commission established a Transmission Pricing Technical Group (TPTG) in April 2009 to provide advice and assistance on the TPM review.[31] The CEO Forum (the New Zealand Electricity Industry Steering Group) established a working group, involving consumer representatives, to undertake a review of transmission pricing around the same time, and formally submitted a report to the Electricity Commission in December 2009.[32]

2.3.2 The Electricity Commission began the TPM review for the following key reasons:[33]

(a) the Electricity Commission had approved Transpower making transmission investments in excess of $2.6 billion;

(b) it was recognised that there was a potential for power flows across the grid to change as a result of investment in transmission and generation and changes in the location of demand;

(c) there was an increasing emphasis on security of supply; and

(d) several parties had requested the Commission to review aspects of the TPM.

2.3.3 The Electricity Commission completed two rounds of consultation in 2009 and 2010 on options for the design of the TPM.[34]

2.3.4 The Authority replaced the Electricity Commission on 1 November 2010 and continued the TPM review. The Authority took into consideration the work of the Electricity Commission on the TPM review and the advice from the CEO Forum that the TPM review should be the Authority's priority. The Authority subsequently:

(a) established the Transmission Pricing Advisory Group (TPAG). The TPAG comprised an independent Chair and consumer and participant representatives and was tasked with advising the

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31 Information on the TPTG is available at http://www.ea.govt.nz/our-work/advisory-working-groups/tptg/.

32 Available at http://www.ea.govt.nz/document/6616/download/our-work/programmes/priority-projects/transmission-pricing-review/stage1/.

33 Electricity Commission, April 2009, *Overview: Transmission Pricing Review Project*, available at: http://www.ea.govt.nz/document/1540/download/our-work/programmes/priority-projects/transmission-pricing-review/stage1/.

34 The Electricity Commission's stage 1 and stage 2 documents are available at: http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/.

Authority on the TPM. The TPAG provided the Authority with analysis and findings on options for the TPM in August 2011 but was unable to provide unanimous recommendations on the most significant aspects of the TPM;[35] and

(b) consulted in early 2012 on a decision-making and economic framework for the TPM review. The Authority published the decision-making and economic framework in May 2012.[36]

Process for reviewing the TPM

2.3.5 Subpart 4 of Part 12 of the Code sets out the purpose of the TPM and the process for developing and approving the TPM. In broad terms, clauses 12.77 to 12.79 establish the purpose of the TPM. Clauses 12.80 to 12.84 and clauses 12.91 to 12.94 set out a process to develop the TPM, including a process to be followed by the Authority. Clauses 12.85 to 12.87 relate to reviews of the TPM.

2.3.6 As the TPM is a schedule to the Code, it is necessary for the Authority to comply with the Electricity Industry Act 2010, in particular with section 38 of the Act, when amending the TPM. That section provides that the Authority may amend the Code at any time, subject to section 39 of the Act (which sets out consultation and other requirements for proposed Code amendments). In addition, section 32(2)(b) prohibits the Authority from doing anything under the Code which the Commerce Commission is Authorised or required to do or regulate under Parts 3 and 4 of the Commerce Act 1986. And pursuant to section 54V of the Commerce Act the Authority must consult with the Commerce Commission in certain circumstances).[37]

2.3.7 The Authority has issued a consultation charter that includes guidelines relating to the process for amending the Code, and consulting on proposed amendments.[38] The consultation charter includes the Authority's Code Amendment Principles (CAPs). The CAPs provide guidance and structure about applying the Authority's statutory objective when

35 Information on the TPAG is available at, http://www.ea.govt.nz/our-work/advisory-working-groups/tpag/.

36 Electricity Authority, May 2012, Decision-making and economic framework for transmission pricing methodology: decisions and reasons, available at, http://www.ea.govt.nz/document/16502/download/our-work/programmes/priority-projects/transmission-pricing-review/.

37 Section 54V(1) of the Commerce Act requires the Authority to consult with the Commerce Commission before amending the Code in a manner that will, or is likely to, affect the Commerce Commission in the performance of its functions or exercise of its powers under Part 4 of the Commerce Act.

38 The Consultation Charter is available at: http://www.ea.govt.nz/document/5133/download/about-us/documents-publications/foundation-documents/.

considering amendments to the Code, and how potential amendments to the Code should be assessed, particularly when the cost-benefit assessment required by the Electricity Industry Act 2010 is inconclusive.

2.3.8 The Authority, in reviewing the TPM, considers the requirements set out in the Code, the Act, and the CAPs (consultation charter).

Material change in circumstances

2.3.9 Clause 12.86 of the Code states that the Authority may review an approved transmission pricing methodology if it considers that there has been a material change in circumstances. Since the TPM came into force in 2008:

(a) over $2 billion worth of transmission investment has been approved - by the Electricity Commission before November 2010 and by the Commerce Commission since November 2010. This has included major investments such as the HVDC pole 3 and the North Island grid upgrade. The costs of those investments must be recovered under the TPM (refer clause 12.77 of the Code);

(b) there have been significant changes to the regulatory framework, with the Authority replacing the Electricity Commission from 1 November 2010, and the function of approving grid investments being transferred to the Commerce Commission; and

(c) advances in technology and the reducing costs of computational power have made available more sophisticated means of allocating transmission costs.

2.3.10 Although the Code does not define what is meant by "material change in circumstances", the Authority is of the view that, by whatever definition, and whether regarded individually or together, the significant changes referred to above constitute a material change in circumstances of the type anticipated by clause 12.86.

2.3.11 The Authority considers that, even if the Code did not include clause 12.86, the change in circumstances that has occurred since 2008 means that a review of the TPM is warranted.

2.3.12 In this context, the Authority has continued the TPM review initiated by the Electricity Commission. The Authority is considering (and reviewing) the TPM in its entirety. This is consistent with ensuring that the TPM meets its purpose, as specified in clause 12.78 of the Code, and that the TPM is consistent with the Authority's objective. The Authority considers that there is considerable value in having a durable TPM, and this means it needs to be flexible so that it adjusts automatically to changing circumstances.

Q1.	What are your views about the materiality of changes in circumstances since the current TPM came into force in 2008?

Process: the Code, the Act and the CAPs

2.3.13 Subpart 4 of Part 12 of the Code outlines requirements for the Authority, and for Transpower, to follow when developing a TPM.

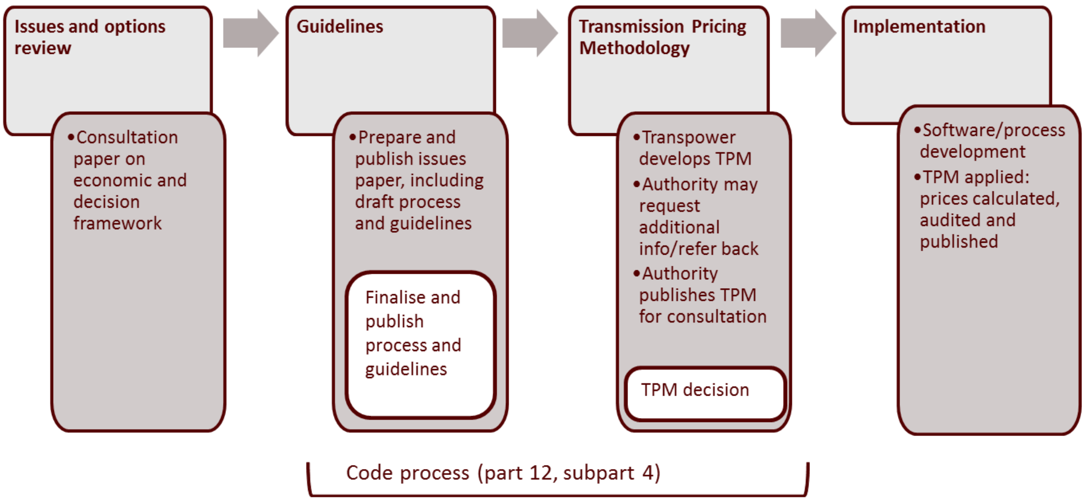
2.3.14 The Authority notes that the provisions of the Code that set out, or constrain, the approaches for the Authority to amend the TPM are inconsistent with the Authority's discretion to amend the Code: delegated legislation such as the Code can neither extend nor fetter the powers conferred by Parliament to amend the Code.

2.3.15 Nevertheless, it is the Authority's view that adopting a process that is consistent with the process set out in the Code is consistent with the requirements of the Electricity Industry Act 2010.

2.3.16 The Authority has taken into account the CAPs in establishing a proposal to amend the TPM, and in preparing the guidelines to be followed by Transpower when developing a new TPM. When the Authority undertakes the consultation required by section 39 of the Act (which the Authority proposes to undertake at the same time as carrying out the consultation anticipated by clause 12.92 of the Code) the Authority will again consider and apply the CAPs to the proposed TPM.

2.3.17 An overview of the process that the Authority proposes to follow for developing the TPM is set out in Figure 4.

Figure 4: Overview of the Code process for reviewing the TPM



2.3.18 The Authority is proposing to adopt a process for reviewing the TPM that is consistent with the process for developing and reviewing the TPM as set out in clauses 12.79 to 12.83, 12.87, and 12.91 to 12.94, of the Code. This process consists of the Authority:

(a) publishing an issues paper (i.e. this paper) that contains the proposed process and the proposed guidelines for Transpower to follow in developing a new TPM. This paper also seeks feedback on the Authority's assessment of the nature and materiality of the problems with the current TPM and the Authority's preferred option for the TPM;

(b) considering feedback received on the issues paper. The Authority may allow for a further round of consultation to seek feedback on issues raised through submissions for further analysis;

(c) determining the final guidelines and final process for Transpower to follow in preparing a TPM;

(d) requesting Transpower to submit a proposed TPM. Clause 12.79 of the Code requires Transpower, in developing a TPM, to assess the TPM against the Authority's objective;

(e) considering the proposed TPM and either approving the TPM for consultation (in certain circumstances the Authority may request Transpower to submit a revised TPM before approving the TPM for consultation) or amending the proposed TPM before the TPM is published for consultation; and

(f) consulting on the proposed TPM as soon as practicable. As the TPM is a schedule to the Code, the Authority's consultation must meet the requirements of section 38 of the Electricity Industry Act 2010.

2.3.19 The Authority will make a decision on the proposed TPM (including the commencement date) after considering submissions on the proposed TPM. Clause 12.79 of the Code states that the Authority will assess the TPM against the Authority's objective.

Q2. What comments do you have on the process that the Authority has outlined for developing and approving a new TPM? Describe and explain any variations to the process that you consider desirable.

3. Decision-making about the TPM

Key points

The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The Authority considers that the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers by facilitating efficient investment in the electricity industry and by facilitating efficient operation of electricity infrastructure.

Efficient participation in the regulation of the TPM is a key consideration. Establishing a robust and durable approach to the TPM will improve efficient investment in the electricity industry and improve efficient operation of the electricity industry.

The Authority has an economic framework that sets out a hierarchy of approaches that the Authority will use to identify and assess options for the TPM:

a) market-based charging approaches, being market or market-like charging approaches;

b) exacerbators-pay charging approaches;

c) beneficiaries-pay charging approaches; and

d) alternative charging approaches.

3.1 The Authority's objective

3.1.1 The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.[39] The Authority published the *Interpretation of the Authority's statutory objective* in February 2011.[40]

3.2 Decision-making and economic framework for the TPM

3.2.1 The Authority released a decision-making and economic framework (economic framework) for the TPM in May 2012.[41] The purpose of the

39 Electricity Industry Act 2010, section 15. http://www.ea.govt.nz/document/12803/download/about-us/documents-publications/foundation-documents/.

40 This document is available at http://www.ea.govt.nz/document/12803/download/about-us/documents-publications/foundation-documents/.

41 Electricity Authority, May 2012, Decision-making and economic framework for transmission pricing methodology: decisions and reasons, available at, http://www.ea.govt.nz/document/16502/download/our-work/programmes/priority-projects/transmission-pricing-review/.

economic framework is to clearly set out how the Authority's objective will underpin decisions about the TPM and to provide the Authority's views on how the Authority will decide between the options for allocating the costs of transmission services.

3.2.2 The Authority considers that the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers. This recognises that efficiency and reliability in the electricity industry involve facilitating:

(a) efficient investment in the electricity industry through providing incentives so that the right investments occur at the right time and are in the right place. These investments can be in the transmission grid, generation (including distributed generation), distribution networks or in demand-side management; and

(b) efficient operation of the transmission grid, generation (including distributed generation), distribution networks and demand-side management. This means providing incentives so that the day-to-day operation of transmission, generation, distribution and demand-side management involves an efficient trade-off between reliability and cost.

3.2.3 Efficient participation in the regulation of the TPM is a key consideration, but these effects operate through the above efficiency criteria. The TPM has been subject to considerable debate, lobbying and court action over many years. Establishing a robust and durable approach to the TPM will firstly improve efficient investment in the electricity industry by reducing regulatory risk regarding the on-going prospect of changes to the TPM, and secondly improve efficient operation of the electricity industry by increasing productivity through reducing the inputs required to lobby and review the methodology.

3.2.4 The Authority's CAPs establish a structure for ensuring that any Code amendment is consistent with the statutory objective, and describe how potential amendments to the Code should be assessed when quantitative cost-benefit analysis yields inconclusive results.

3.2.5 The economic framework and the CAPs are complementary – the framework provides additional guidance about how the statutory objective will inform the development and approval of the TPM. The Authority still applies the CAPs when considering any amendment to the Code to amend the TPM.

3.3 Economic framework

3.3.1 The economic framework sets out a hierarchy of approaches that the Authority will use to identify and assess options for the TPM. The Authority prefers options that involve, in order of preference:

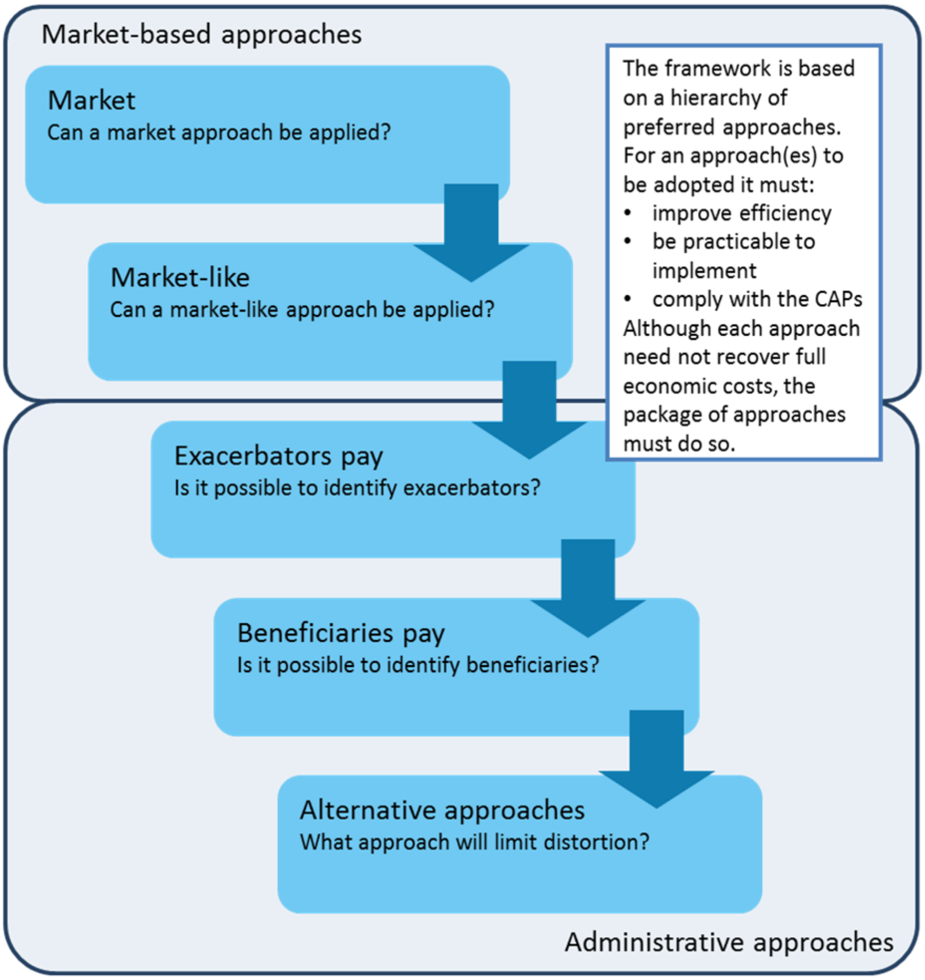
(a) market-based charges;

(b) exacerbators-pay charges;

(c) beneficiaries-pay charges; and

(d) alternative charging options.

Figure 5: Decision-making and economic framework for transmission pricing[42]



[42] Note that for clarity the Authority has used "market" to describe the pricing approaches in workably competitive markets rather than the term used in the paper *Decision-making and economic framework for transmission pricing Decisions and reasons,* which was "market-based". This issues paper uses the term "market-based" when generically referring to both market approaches and market-like approaches.

3.3.2 In applying the economic framework the Authority will try to achieve a result where transmission charges are efficient, practicable to implement and allow Transpower to recover the allowable revenues approved by the Commerce Commission (i.e. the full economic costs of Transpower's transmission services).

3.3.3 The Authority recognises that transmission costs may be recovered through a combination of market-based, exacerbators pay, beneficiaries pay and alternative approaches to charging.

Market-based charges

3.3.4 The Authority's first preference is for the TPM to apply a market-based approach for determining charges. A market-based approach should result in charges established through the interaction of willing buyers and willing sellers in a workably competitive market (i.e. a market approach), or charges that are likely to mimic or replicate the pricing outcomes achieved by a workably competitive market (i.e. market-like).

3.3.5 The New Zealand wholesale electricity market is a market approach that establishes half-hourly prices for electricity through the interaction of willing buyers (i.e. electricity retailers and grid-connected major users) and willing sellers (i.e. generators). Similarly, the arrangements established by the Code for connection to the transmission grid can be considered to be a market-like approach, involving Transpower and the connecting party negotiating the service levels and price of connection (subject to bounds established by the Code).

3.3.6 A market approach tends to be efficient because buyers and sellers, in a workably competitive market, can seek to achieve efficiency gains whenever and wherever possible. Prices set through a market approach are agreed between parties who willingly participate in the transaction or between parties who have agreed to the process and to a formula for determining prices. Prices will not exceed the private benefit of the party to the transaction because a willing buyer would not be prepared to complete the transaction if prices exceeded their private benefit. The main reasons a market option may not be a viable or efficient approach are that: there is not workable competition, there are divergences between private and social costs and benefits (i.e. there are externalities), or there is potential for parties to free-ride (i.e. opportunities for parties to enjoy the benefits without making an appropriate payment).

3.3.7 A market-like pricing approach may be appropriate where there is a market failure and workable competition is not possible. A market-like approach involves setting prices through a method or methods that seek to replicate what would happen in a workably competitive market without externalities by identifying the parties to the transaction and each party's benefit from the transaction. Prices should not exceed the private benefits of the parties to the transaction.

Administrative approaches

3.3.8 The Authority considers that an administrative approach to charging should be preferred when a market-based charge is inefficient or impracticable or does not fully recover the economic costs of transmission services. The Authority's order of preference for administrative approaches is:

(a) exacerbators pay – an exacerbator is a party whose action or inaction lead to cost externalities (i.e. costs on others) and who could change their behaviour if they faced the full cost of that action or inaction;

(b) beneficiaries pay – a beneficiary is a party for whom the private benefits of a service exceed its share of the costs and who would therefore be willing to pay for a portion of that service if that were the only means of acquiring the benefit; and

(c) alternative charging options where the costs are recovered from the users of the associated services through some other mechanism, such as a low-rate, broad-based charge.

Exacerbators pay

3.3.9 A transmission exacerbator is a party whose actions or inactions give rise to a transmission cost and that party does not face the full, or any, cost of their action or inaction.[43] An exacerbators-pay approach is required to address market failures resulting from externalities where transmission costs are not met by the exacerbator but are instead borne by other transmission customers.

3.3.10 An example of an exacerbator in the electricity sector is a grid-connected major user that uses low power factor equipment that results in an excessive draw of reactive power from the transmission grid. To address the poor power factor, Transpower might invest in static reactive compensation equipment. However, if the exacerbator is not be required

[43] An exacerbator is a party imposing negative externalities on others. For example, an importer of goods into New Zealand that does not undertake appropriate cleaning/bio-security measures can significantly exacerbate the costs of bio-security inspections but do not benefit from the inspection. The parties benefiting from the inspection regime are New Zealand industry and community protected from biological incursions.

to pay for the full costs of that investment, the additional cost will be borne by other grid users.

3.3.11 The Authority considers that adopting an exacerbators-pay approach will promote efficiency by making exacerbators face the social cost of their action or inaction.[44] A charge calculated using the exacerbator-pays approach should reflect the cost, over and above any already committed costs, resulting from an exacerbator's actions or inactions. Faced with the social cost of their decision, the exacerbator will have appropriate incentives to behave efficiently.

Beneficiaries pay

3.3.12 The beneficiaries-pay approach involves using a method or methods to determine the parties that benefit from a transmission service, and each party's private benefit. A beneficiaries-pay approach is most likely to be required where the parties to a transaction will not self-identify or have the ability to free-ride or hold out, thereby making market or market-like approaches either not efficient or impractical (e.g. due to transaction costs). The prices that apply to beneficiaries should reflect the lesser of the charge that will fully recover the costs of the transmission grid being paid for by beneficiaries or the anticipated (ex-ante) value to them of the services provided by the grid.

3.3.13 An example of a beneficiary of the transmission grid and transmission services is a grid-connected major user – who benefits from transmission services through obtaining electricity from generators located across the grid and through access to the wholesale market. The beneficiary may also benefit from grid reactive support services. The benefit the major user obtains from transmission services can change over time.

3.3.14 Another example of a beneficiary of the transmission grid and transmission services is a generator that is connected to the grid at a point that is distant from the load they supply. The generator benefits from transmission services through access to the wholesale market. The benefit the generator obtains from transmission services can change over time.

Emerging regulatory practice for beneficiaries-pay

3.3.15 A beneficiaries-pay approach to transmission charging is emerging as common practice internationally. The trend reflects moves by decision-

[44] An efficient price for an exacerbator is the marginal social cost of their exacerbating activity. Setting a price equal to the marginal cost of the exacerbating activity means exacerbators will only undertake exacerbating activity when their marginal private benefit exceeds marginal social costs.

makers to adopt a cost causation principle which will ensure that only those parties benefiting from transmission facilities are charged for the associated costs.[45] In particular, emerging practice involves adopting a market-like approach that grants the parties benefiting from a transmission investment the ability to exercise decision rights about the investments from which they are expected to derive a benefit.

3.3.16 In the Argentinean and New York electricity markets beneficiaries have been given decision rights over major new transmission investment through a public contest method.[46] A similar method was developed in New Zealand in 2002 by the Transport Working Group of the Electricity Governance Establishment Board.

3.3.17 The key advantage of assigning beneficiaries some decision rights is that the beneficiaries are the ones best placed to determine whether the expected benefits (to them) of the proposed investment exceed the costs (to them) of the proposed investment. If the benefits do not exceed the costs, the beneficiaries are unlikely to be willing to pay the costs and the investment should not happen. Hold-out problems can be managed by allowing super-majorities (e.g. 70-80%) to bind all parties to pay for an upgrade and by allowing contestability to assist parties build coalitions to get the super-majority.

3.3.18 As the Commerce Commission is responsible for regulating transmission investment, the Authority is not able to implement an approach to allocate transmission costs that involves decision rights over whether an investment goes ahead. However, the Authority can consider introducing a transmission cost allocation methodology that would be consistent with a decision rights approach for transmission investments, if the Commerce Commission considered that approach to be appropriate (and if the TPM changes meet the Authority’s decision-making criteria).

Alternative charging options

3.3.19 The Authority considers that an alternative charging option may be needed when a market-based charging approach or charges based on

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45 Illinois Commerce Commission v FERC, 576 F.3d 470, 476 (7th Cir., 2009, citations omitted), available at, http://www.ferc.gov/legal/court-cases/opinions/2009/PT1FG750-opinion.pdf. Also refer Federal Energy Regulatory Commission, Chairman Wellinghoff, On Transmission Planning and Cost Allocation Notice of Proposed Rulemaking, Docket No. RM10-23-000, Statement: 17 June 2010.

46 For further detail on the Argentinian arrangements, refer: Littlechild, SC and Skerk, CJ: “Regulation of transmission expansion in Argentina Part I: State ownership, reform and the fourth line”, CMI EP 61, 2004, pp 27-28.

exacerbators pay or beneficiaries pay are not efficient, practicable or do not recover the full costs of transmission services.

3.3.20 The Authority considers that the key principles for identifying an alternative charging option that is efficient are that the option should:

(a) minimise, to the extent practicable, any distortion from the efficient level in use of the transmission grid resulting from the imposition of the charge;

(b) minimise, to the extent practicable, any distortion in grid-related investment from the efficient level resulting from the imposition of the charge; and

(c) ensure the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered so future investment is not stifled by the concerns of investors that they will not receive a return on their approved investments.

3.3.21 An example of an alternative charging option is to use a residual low-rate, broad-based charge to recover from a large number of parties the costs of maintaining, upgrading and extending the grid. Such an approach is commonly referred to as “postage stamp” pricing.

4. Problem definition: does the current TPM promote overall efficiency?

Key points
The Electricity Authority has applied its economic framework hierarchy to assess inefficiencies with the current TPM.

The Authority considers that the **current connection charge** and arrangements for obtaining and providing connection services generally operate effectively and promote efficient investment in the electricity industry. However, drafting deficiencies (loopholes) in the current TPM provide connecting parties with the ability to shift connection costs into the interconnection charge. This is not efficient.

The Authority has identified problems with the **current HVDC charge.** These charges result in a considerable level of inefficiency, primarily because it disincentives efficient South Island generation investment and encourages an overbuild of HVDC transmission investment. Further, it is not durable, being subject to on-going lobbying and reviews. The resulting potential for change does not promote efficient investment.

The Authority has identified problems with the **current interconnection charge**. These charges result in a considerable level of inefficiency, primarily by bringing forward the need for new transmission, dis-incentivising efficient peak demand reductions, and dis-incentivising major new loads from setting up in the most efficient location.

The Authority has identified that the provision of **static reactive support** is the result of an externality. The parties (exacerbators) that cause reactive power off-take at times of system peak loading are in the upper South Island and upper North Island. The costs of investment in static reactive assets are recovered through the interconnection charge rather than from exacerbators.

The Authority has identified that the provision of **dynamic reactive support** is to make the grid more robust to contingent events that cause voltage instability (an externality) and to enable greater power transfer into a region. It is unlikely to be practicable to charge the exacerbators of dynamic reactive support, but it may be appropriate to charge beneficiaries of the greater power transfer it enables. However, the costs of Transpower's dynamic reactive support investments are currently recovered through the interconnection charge rather than from beneficiaries.

The Authority considers that the **prudent discount policy** exists to mitigate the extent to which the current TPM encourages inefficient bypass of, or disconnection from, the grid. The need for a prudent discount arrangement is contingent on the implications that proposed charging arrangements will have for disconnection from the grid or bypass of the grid.

4.1 Introduction

4.1.1 The Authority has identified several aspects of the current TPM that are not consistent with promoting the long-term benefit of consumers because those aspects preclude efficient investment in the transmission grid, generation, distribution and efficient investment by electricity consumers, or preclude efficient operation of the transmission grid, generation, distribution and demand-side management.

4.1.2 This chapter discusses the nature and materiality of problems with:

(a) the connection charge, HVDC charge and interconnection charge components of the current TPM; and

(b) the approach for recovering the costs of network reactive support services.

4.1.3 This chapter also discusses the prudent discount policy and issues associated with the risk of inefficient bypass or disconnection from the grid.

TPAG assessment of the problems with the current TPM

4.1.4 The TPAG assessment of the efficiency of the current TPM identified the following potential problems:[47]

> "a) the allocation and structure of the HVDC charge is a locational signal that leads to inefficient price signals for new investment in generation;
>
> b) the current boundary of interconnection and connection assets may not provide sufficient incentives on participants to avoid reliability-driven transmission investments and it may be feasible to clearly identify the beneficiaries of more assets than the assets currently classified as connection assets; and
>
> c) the arrangements for minimum power factor may not provide efficient signals to grid users about the costs of reactive power compensation and it may be possible to clearly identify the beneficiaries of static reactive compensation investments."

4.1.5 The Authority has identified similar problems to those found by the TPAG.

4.2 Problems with the connection charge

4.2.1 The connection charge under the TPM recovers Transpower's costs of connecting a transmission customer's electrical assets to the grid. A connection charge is calculated each year for each transmission customer by totalling the asset component, maintenance, operating and, for injection

[47] TPAG, Transmission pricing analysis report to the Electricity Authority, 31 August 2011, page 3, available at: http://www.ea.govt.nz/document/14915/download/our-work/advisory-working-groups/tpag/.

customers,[48] the overhead cost recovery components.[49] However, the asset component of the costs of providing new connection assets is recovered under the terms of investment contracts agreed between a transmission customer and Transpower.[50]

4.2.2 Transmission customers who wish to connect to the grid must enter into a transmission agreement with Transpower.[51] Transmission agreements set out the terms on which Transpower will permit a transmission customer's assets to be connected to the grid and will make the grid available for the conveyance of electricity.[52] New connection services are provided under an investment contract, and the asset component of the associated costs is recovered through a charge agreed between Transpower and the transmission customer.

4.2.3 The connection service involves point connection and grid connection. Point connection provides for connection of the transmission customer's assets to the grid and provides the physical means by which electricity can transfer between the grid and the transmission customer.[53] Grid connection involves the provision of connection assets for the conveyance of electricity between each point of connection and the grid.[54]

4.2.4 The extent of connection assets, in particular the location of the boundary between the grid connection and interconnection assets, is defined in the Code. The current TPM adopts a 'deep connection' approach to specifying connection assets by identifying the assets that exist to connect a

[48] The connection charge for injection customers (generators) includes a share of overhead costs (i.e. indirect costs such as head office). Off-take customers (distributors and grid-connected major users) are charged for overhead costs through the interconnection charge.

[49] Schedule 12.4, clause 8(1) of the Code. The approach to calculating each cost component of the connection charge formula is described in the TPM.

[50] Clause 12.71 of the Code. Investment contracts provide for new investments determined and agreed between Transpower and a transmission customer. They may also provide for the replacement of end-of-life connection assets. Connection services are also provided under agreements entered into before 1 April 2008. These agreements are referred to as input connection contracts, new investment agreement contracts and notional embedding contracts.

[51] Clause 12.8 of the Code.

[52] Schedule F2 of the Code, Benchmark Agreement, clause 3.3.

[53] Schedule F2 of the Code, Benchmark Agreement, clause 26.

[54] Schedule F2 of the Code, Benchmark Agreement, clause 34. Point connection and grid connection do not imply the provision of an interconnection service to the transmission customer. However, transmission customers must pay charges in accordance with the TPM, which includes charges that recover the costs of assets associated with the interconnection service. Interconnection assets are provided for use by the system operator for the conveyance of electricity through the grid under clause 12.111 of the Code.

connecting party's electrical assets with the core grid (i.e. the grid connection service). A connection asset is defined as:[55]

(a) at a connection node, any grid asset, other than voltage support equipment that is for grid voltage support purposes, that has not been installed at a customer's request;

(b) at an interconnection node:

(i) any grid asset that is specifically required to connect a customer;

(ii) any grid asset that is used both to connect a customer and for grid operation generally; and

(iii) a proportion of the land and buildings at the connection location; and

(c) any grid asset that is a connection link.

4.2.5 The 'deep connection' approach is based on a physical definition of connection assets that was developed by the Electricity Commission. According to the Electricity Commission:[56]

> The key distinguishing feature of connection assets is that there are no 'loop flow' effects on them, and so power always flows in one direction, making it possible to identify causers/users of the asset. If there are multiple connection parties using particular connection assets, then, as with any shared asset, some form of cost apportionment is required.

4.2.6 Thus, the nature of the connection service is that Transpower builds, maintains and operates a ring-fenced set of connection assets in a configuration that meets a connecting party's requirements for capacity and reliability at a particular location, and also meets the grid reliability standards. These assets provide a point-to-point electrical interface between the connecting party's assets (i.e. a generator, distribution grid or a large industrial site) and a suitable node on the interconnection part of the grid. These two points may be immediately adjacent or, in some cases, many kilometres apart, requiring sections of transmission line.

4.2.7 Transpower's natural counterparty for the connection service is the party that owns the electrical assets for which the grid connection is sought. This party will derive a private benefit from connection of their assets to

[55] Schedule 12.4, cl.6(1) of the Code.

[56] Electricity Commission, February 2005, The Commission's Statement of Reasons in relation to the Proposed Guidelines for Transpower's Pricing Methodology, pages 18-19.

the grid and will have the information, incentive and capability necessary to determine price/quality trade-offs (within the limits imposed by the grid reliability standards) and agree on service levels. Connection is thus a service that is practical to arrange through bilateral negotiation between Transpower and a single connecting party (or at most possibly two or three parties where it is efficient to share connection assets at a particular location).

4.2.8 Connection is generally a contestable service, in that the connecting party can choose to undertake much of the investment. However, in practice Transpower is frequently chosen by the connecting party to undertake significant portions of the required asset investment, particularly where 220 kV and 110 kV assets are required.

TPAG view of problem relating to the connection charge

4.2.9 The TPAG identified a problem, described in paragraph 4.1.4 above, with the boundary between connection and interconnection assets, which is used to allocate connection and interconnection costs.

4.2.10 The TPAG problem definition suggests that the definition of connection assets should be broadened to include the costs of interconnection investments required due to a connection investment (for example, by using an economic definition of connection assets). In other words, the TPAG problem definition suggests resolution by requiring connection customers to pay not only for connection assets but also for interconnection assets that would not be required ‘but for’ their connection.

4.2.11 The Authority has considered the problems raised by the TPAG associated with the boundary between connection and interconnection, in the discussion of problems with targeting the interconnection charge in section 4.4.

Nature and materiality of the problem – connection charges

4.2.12 The Authority understands that transmission customers are broadly comfortable with the status quo arrangements for the connection service. Many investment contracts have been entered into by Transpower and connection counterparties in recent years.[57] The Authority considers that

[57] The evidence provided by a review of investment contracts signed between Transpower and connecting parties from 1 January 2006 to the present time supports this view. In this period, 72 investment contracts, covering a very wide range of connection investment needs with some 32 unique counterparties, have been agreed. This represents a steady contract completion rate of approximately one contract per month over this period.

the arrangements for obtaining and providing connection services are generally operating effectively and promote efficient investment in the transmission grid (including connection assets), in generation, distribution and by electricity consumers (for example, direct-connect major users).

Q3.	**Do you agree with the Authority's view that the arrangements under the TPM for recovering connection costs are generally efficient? Explain your answer.**

Gaming incentive at the boundary of connection and interconnection assets

4.2.13 Despite its generally favourable view of the current connection charges regime, the Authority has identified two relatively minor problems with the current arrangements that may result in inefficient transmission pricing outcomes.

4.2.14 The first problem involves the potential for connection customers to seek to inefficiently shift connection costs into the interconnection charge. In principle, service and cost responsibility boundaries can create inefficient incentives where different cost allocation rules apply on either side of an asset boundary and one set of rules is more favourable to a connection party than the other.

4.2.15 In the case of the connection/interconnection asset boundary, incentives exist in the current TPM for parties that pay for specific connection assets to seek to have them reconfigured in a way that would reclassify some of those assets as interconnection assets. Under a strict application of the current TPM, this would have the effect of shifting some costs into the interconnection charge and provide a windfall gain to one connection party at the expense of all transmission customers that face interconnection charges.[58] This could promote inefficient investment as parties connecting to the grid in this situation would not face the full costs of associated investment.

4.2.16 Transpower has advised the Authority of the following recent examples of connection assets that may be reclassified as interconnection assets:[59]

[58] The same opportunity would only arise for connection service procured under an investment agreement at the end of the contract term. Contract terms for investment contracts completed since 1 January 2006 have terms ranging from 3 to more than 50 years, with a predominance of contract terms in the range 15 – 25 years.

[59] The information for these examples has been provided by Transpower.

(a) Te Awamutu – Hangatiki 110 kV link. Transpower considers that a second circuit paralleling the existing single circuit from Karapiro is the most cost effective option to improve the reliability of supply to Te Awamutu. The connection customer at Te Awamutu prefers a separate, longer line route – from Hangatiki – for the perceived additional security benefits this option would provide. However, under this alternative configuration, both the new circuit and the existing Karapiro – Te Awamutu circuit would create an interconnection loop and become interconnection assets; and

(b) Tauranga – Waihou 110 kV link. Options to provide additional connection capacity to the northwest of Tauranga have been considered for some time. One option raised by the local connection customer is to connect the Tauranga GXP with a line to Waihou in the Thames Valley. This configuration would create an interconnection loop which, under the current TPM, would have the effect of redefining some current connection assets as interconnection assets.

4.2.17 The Te Awamutu-Hangatiki circuit option is understood to be proceeding as a customer-owned transmission line and to include a new investment contract that provides that the arrangement will not redefine existing connection assets as interconnection assets. The parties have agreed in this case that asset reclassification is an unintended consequence of the new investment under current TPM arrangements and have negotiated an investment contract that avoids shifting costs into the interconnection charge.

4.2.18 Although the Tauranga – Waihou line option has been discussed for a number of years, the Authority understands the project is not currently being actively pursued. However, the Authority understands that the connection customer has agreed that the reclassification of connection assets would be an unintended consequence of the current TPM arrangements.

4.2.19 If connection assets are reclassified as interconnection assets, this could result in cost reallocation of connection assets potentially valued at several million dollars, depending on the particular reconfiguration involved.[60] Although this would represent a fairly small component of overall connection revenues, the asset values in the context of the particular total project costs are likely to be material.

[60] For example, the connection assets involved in the Te Awamutu case that could become reclassified would include substations and lines involving Hangatiki, Te Awamutu, Karapiro and Cambridge.

Q4.	**What comments do you have about the potential for inefficient outcomes to arise from incentives to shift connection costs into the interconnection charge?**

Incentive to hold out so that Transpower replaces connection assets to satisfy grid reliability standards

4.2.20 The second problem identified by the Authority also involves the potential for connection customers to seek to inefficiently shift connection costs into the interconnection charge by refusing to agree to an investment contract with Transpower for the replacement of connection assets. This problem arises from the current benchmark agreement and the TPM.

4.2.21 An investment proposal is the fall-back option when the parties are unable to negotiate an investment contract within 6 months.[61] Under an investment proposal the asset investment costs are recovered through a connection charge, but this charge may fail to allocate the full investment costs to the connection party that derives a private benefit from the investment. This is because connection assets are valued with reference to a standard building block asset valuation register (in which the asset values have not been reviewed for some time),[62] as opposed to being valued at the actual cost of the replacement investment. The difference between the cost of the grid upgrade plan and the actual cost is recovered through the interconnection charge.

4.2.22 Transpower has advised the Authority there have been a small number of cases where connection upgrades have occurred under an investment proposal rather than under an investment contract. However, Transpower has indicated that several connection asset replacement projects will be necessary in the next few years, and anticipates of the order of five cases per year over the next five years and beyond.

4.2.23 The level of inefficient cost transfer is situation-specific but could be in the range of 10 to 30 per cent of replacement project costs with an increasing trend over time as the asset valuation register becomes more out of date. Replacement projects (for example, switchgear and supply transformer replacements) typically cost in the range of several hundred thousand dollars to a few million dollars. The potential transfer of costs to the parties that pay interconnection charges is thus considered to be material, and has the potential to lead to inefficient investment decisions.

[61] Benchmark agreement, clause 40.2(f).

[62] Refer schedule 12.4, cl.12 of the Code.

Q5.	**Do you agree that there is the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract? Explain your answer.**
Q6.	**Do you consider that there are any other problems with the connection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem.**

4.3 Problems with the HVDC charge

4.3.1 The HVDC charge currently recovers the costs of the HVDC link from South Island generators (HVDC customers).[63] The charge is calculated for each HVDC customer at each South Island generation location, with the allocation of costs proportional to peak (MW) generation at each generation location, based on HAMI (historical anytime maximum injection).[64]

4.3.2 HAMI for a customer at a South Island generation connection location means either the average of the 12 highest injections at that location during the capacity measurement period for the relevant pricing year; or the average of the 12 highest injections at that connection location during any of the four immediately preceding pricing years, whichever is highest.

4.3.3 The design of the HVDC charge reflects the thinking in the mid-late 1990s at the time the basic design of the current TPM was developed that efficiency would be enhanced if South Island generators faced the costs of HVDC assets. The decision reflected a view that the primary contributors to the costs of the existing HVDC assets were South Island generation plant and North Island consumers, but that there were efficiency gains from improving locational signals on generators and avoiding inefficient effects on consumer behaviour.[65]

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[63] A HVDC customer is the owner or operator of South Island generation directly connected to grid assets, or a local grid to which South Island generation is connected, either directly or indirectly. Refer schedule 12.4, clause 3.

[64] Schedule 12.4, clauses 31-33 of the Code.

[65] More detail on the development of the HVDC charge is available in the following documents: Electricity Commission, Transmission Pricing Methodology – Summary of submissions and provisional response, 11 April 2007, paragraph 5.2.13; and Electricity Commission, Explanatory paper - Commission’s final decision HVDC transmission pricing methodology, March 2006, paragraph 3.3.16.

4.3.4 The Authority has now reviewed the HVDC charge in light of developments since the basic design of the charge was first developed and instituted.

Nature and materiality of the problem – HVDC charge

4.3.5 The Authority has identified three problems with the current HVDC charge resulting in a net cost of an estimated $30 million NPV.

HVDC charges create dynamic inefficiency

4.3.6 The Authority has assessed the extent that HVDC charges are aligned with the private benefits derived from the HVDC link. The analysis, provided in Appendix C, estimates the private benefits derived by various parties from pole 2 and pole 3 of the HVDC link from 2014.

4.3.7 The allocation of costs based on the private benefit derived from the HVDC link should promote investment efficiency through improved investment decision-making and provide benefits from improved durability of the cost allocation methodology.

4.3.8 In particular, parties paying a HVDC charge commensurate with their private benefit will have:

(a) incentives to participate in decision-making about possible new transmission investments and to provide more accurate information to Transpower and the Commerce Commission, while testing the options and costs proposed by Transpower;

(b) stronger incentives to make trade-offs between the benefits and the costs of transmission investment; and

(c) improved incentives to negotiate separate commercial agreements for some ‘economic’ investments in the grid rather than for them to be centrally planned and regulated.

4.3.9 The Authority’s analysis of private benefits derived from the HVDC link indicates that:

(a) South Island generators will, in aggregate, derive a private benefit from pole 2 of about $540 million PV (point estimate) against an estimated HVDC charge related to pole 2 of about $500 million PV. However, some individual South Island generators may not derive a private benefit from pole 2;

(b) South Island generators will derive, in aggregate, a private benefit from pole 3 of about $155 million PV (point estimate) against an estimated HVDC charge related to pole 3 of about $970 million PV.

The private benefit of each generator will probably be less (in aggregate and for each generator) than the portion of their HVDC charges relating to pole 3;

(c) South Island consumers will, in aggregate, derive a private benefit from pole 2 and pole 3 of about $460 million NPV (point estimate), but under current arrangements will pay no HVDC charges;

(d) North Island consumers will, in aggregate, derive a private benefit from pole 2 and pole 3 of about $1380 million NPV (point estimate), but under current arrangements will pay no HVDC charges; and

(e) North Island generators will, in aggregate, face a cost of about $1200 million PV (point estimate) as a result of the HVDC link. However, some *individual* North Island generators derive a private benefit from the HVDC link when there is a north-south power flow.

4.3.10 The Authority considers the consequences of the mismatch between the private benefits from the HVDC link and the current HVDC charges include:

(a) generators declining to carry out efficient investment in the South Island due to concerns about future HVDC costs. For example, new investment in generation in the South Island could require further investment in the HVDC link. This would lead to increased HVDC charges for all South generators without any commensurate increase in their private benefit; and

(b) consumers in both the North and South Islands having an incentive to lobby for future HVDC link upgrades, even if an upgrade is uneconomic because they would not be required to pay a HVDC charge commensurate to their private benefit. Similar incentives apply to North Island generators, as they benefit from the HVDC link when there are north-south power flows but currently don't incur HVDC charges.

4.3.11 As a result, the Authority considers that the current regime for the HVDC is likely to be unstable, which results in significant economic cost, including from lobbying.

Q7. What comments do you have about the Authority's analysis of the private benefits deriving from the HDVC link?

Q8. What comments do you have about the consequences of the material differences between private benefits from the HVDC link and HVDC charges?

Structure of HVDC charge can result in inefficient generation investment

4.3.12 The second problem is that the structure of the HVDC charge can result in inefficient generation investment by:

(a) discouraging investment in South Island generation relative to North Island generation even when South Island generation is more efficient.[66] The Authority is aware of some generation investment that may fall into this category, such as around Nelson, where the HVDC charge appears to discourage generation investment despite it being a net importing region. The estimated cost of inefficient generation investment is $30 million NPV, albeit with considerable uncertainly (refer Appendix C); and

(b) discouraging investment in South Island peak generation capacity.[67]

4.3.13 The Authority also notes that the impact of the current HVDC charge on generation investment may have flow-on effects for transmission investment (refer Appendix C), including:

(a) a small decrease in the expected cost of future HVDC upgrades, resulting in an expected benefit of $5 million PV. Against this, the impact on transmission costs resulting from not charging beneficiaries of the HVDC link must be considered; and

(b) an unclear effect on the need for future interconnection upgrades.

Q9. What comments do you have about the Authority's analysis of the costs of inefficient generation investment resulting from the HVDC charge?

Structure of HVDC charges can result in inefficient operation of electricity assets

4.3.14 The third problem is that the structure of the HVDC charge can result in inefficient use of the grid because using HAMI to determine the HVDC charge discourages South Island generators from operating their generation at full capacity.[68] The Authority is aware of South Island generation that dispatches less than the peak capacity of plant to avoid increasing their HAMI and associated HVDC charges.

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[66] TPAG report, Section 5.2 and Appendix A.

[67] TPAG report, paragraphs 5.3.6 and A.15.8 through A.15.14.

[68] TPAG report, paragraphs 5.3.2 through 5.3.4 and A.15.5 through A.15.6.

4.3.15 The Authority estimates that the inefficient operation of South Island generation capacity results in a cost of less than $5 million PV (refer Appendix C).

Q10. What comments do you have about the Authority's analysis of the costs of inefficient operation of South Island generation resulting from the HVDC charge?

Q11. Do you consider that there are any other inefficiencies arising from the HVDC charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the inefficiencies.

4.4 Problems with the interconnection charge

4.4.1 The interconnection charge recovers all of Transpower's maximum allowable revenue that is not recovered under the HVDC charge or connection charges.[69] The charge recovers the costs of interconnection assets, as well as a proportion of common and overhead transmission-related costs. [70]

4.4.2 This section discusses problems with the interconnection charge under the current TPM, *excluding* arrangements for recovering the costs of grid reactive support (NRS) assets. Problems with recovering NRS costs are examined in section 4.5.

4.4.3 The interconnection charge recovers costs from off-take customers (for the most part distributors and direct-connect consumers but also generators to the extent they consume power from the grid at a connection location). [71] The charge is proportional to the contribution of each off-take customer's regional coincident peak demand (RCPD)[72] – i.e. the average off-take during the N trading periods of highest regional demand, where N is 12 for upper North Island (UNI) and upper South Island (USI) regions or 100 for lower North Island (LNI) and lower South Island (LSI) regions.

4.4.4 The interconnection charge is intended to:[73]

[69] Schedule 12.4, clause 27 of the Code and also Appendix 1 of Schedule 12.4.

[70] That is, excluding the system operator's costs and other unregulated activities of Transpower.

[71] An off-take customer is a customer who has or controls assets into which electricity flows from the grid at a connection location. Refer schedule 12.4, clause 3 of the Code.

[72] Schedule 12.4, clauses 28-30 of the Code.

[73] *Transmission Pricing Methodology, Supplementary Material*, Transpower, June 2006.

(a) spread costs broadly across all consumers; and

(b) incentivise distributors and consumers to act to reduce regional peak demand in order to reduce the need for transmission investments. The incentive is stronger for off-take customers in the UNI and USI regions than for those in the other two regions, which reflects the fact that peak demand in these regions was closer to transmission capacity at the time the current TPM was developed.

Nature and materiality of the problem - interconnection charge

4.4.5 The Authority has identified four problems with the current interconnection charge that, in aggregate, result in an estimated net cost of between $12 million NPV to $170 million NPV, relative to a beneficiaries-pay point of reference. The Authority's analysis of the costs and benefits of the interconnection charging arrangements is provided in Appendix D.

Interconnection charges create dynamic inefficiency

4.4.6 The first problem with the current interconnection charging arrangements is that parties do not generally pay an interconnection charge commensurate with their private benefit from the interconnection assets, and some parties that derive a benefit from interconnection assets do not pay an interconnection charge at all. This means:

(a) generators can benefit from interconnection, but do not pay interconnection charges (except to the extent that they draw power from the grid);

(b) retailers can benefit from interconnection, but do not directly pay interconnection charges, and the charges they pay indirectly do not relate to the private benefits they derive;

(c) consumers do pay interconnection charges (directly in the case of direct-connect major users or indirectly via distributors and retailers) – but the charge paid by a particular consumer is not driven by the private benefit that the consumer derives from the interconnected grid. This is likely to result in on-going debate and lobbying, which will be detrimental to the durability of the TPM regime; and

(d) distributors pay interconnection charges but are able to pass them on to retailers or consumers in full under the current regulatory regime. As a result, distributors do not bear charges related to the benefits they derive from the transmission grid, such as access to the wholesale electricity market to offer interruptible load and reduced costs of managing customers due to fewer outages.

4.4.7 The mismatch between interconnection charges and private benefits is detrimental to efficient transmission investment decision making.[74] In particular, the current interconnection charge does not:

(a) provide an efficient incentive to the parties deriving a benefit from transmission investment to identify and promote better transmission investment options; or

(b) encourage the parties deriving a benefit from transmission services to seek deferral or cancellation of transmission investment where it is efficient to do so.

4.4.8 Where the party that benefits from a transmission service does not face a charge that is commensurate with the costs of investment, they have incentives to overstate the benefits or seek to have the investment brought forward. Moreover, this problem links to the issue raised by the TPAG with the boundary between connection and interconnection assets. Connecting parties do not currently always face the costs of interconnection investments resulting from their connection, despite deriving a benefit from that investment.

4.4.9 The estimated cost of inefficient decision-making because interconnection charges are not commensurate with private benefit is up to $72 million NPV, with a point estimate of $22 million NPV.

4.4.10 Further, the mismatch between charges and private benefits is detrimental to efficient investment in generation and demand-side management.

Inefficient investment in transmission capacity

4.4.11 The Authority's analysis indicates that the current interconnection charge inefficiently brings forward the need for transmission investment that increases transmission capacity from a potentially export-constrained region. The consequence is that generators may not invest in the most efficient location, resulting in an estimated cost of between $12 million NPV and $50 million NPV (point estimate $25 million NPV).

4.4.12 Similarly, the Authority's analysis indicates that the current interconnection charge can, *in some cases*, inefficiently bring forward the need for transmission investment that increases transmission capacity into a potentially import-constrained region. This results in an estimated cost of up to $48 million NPV (point estimate $20 million NPV) by failing to: [75]

[74] TPAG report, para 4.5.3

[75] TPAG report, Section 6.1.

(a) incentivise efficient peak (or, for that matter, anytime) demand reductions in transmission constrained regions;

(b) incentivise major new loads to locate in locations that have sufficient import capacity to meet their demand; or

(c) incentivise investment in, and peak operation of, generation in the region.

4.4.13 The existing regulatory framework does provide some incentives for efficient generation and demand-side investment to defer transmission investment. The RCPD allocation method encourages peak-time demand reductions and peak-time operation of embedded generation, especially in the UNI and USI regions, both of which are typically import-constrained.[76] Under the Commerce Commission's transmission alternatives framework, Transpower can contract for supply- or demand-side measures to defer the need for transmission investment.

4.4.14 Nevertheless, these measures are not always applicable and in some cases there is little incentive for efficient generation or demand-side investment to defer transmission investment.

Other problems with interconnection charges

4.4.15 The other three problems with the current interconnection charge are that:

(a) the RCPD allocation results in a net cost of $5 million NPV through inefficient demand-side response by some direct-connect consumers in the LNI region;

(b) interconnection charges are typically passed on to mass-market customers in a variabilised form resulting in a cost of $30 million from a deadweight loss;[77] and

(c) interconnection charges are forecast to approximately double in the next few years as a result of high levels of transmission investment, much of which will expand transmission capacity and relax peak capacity constraints. There is, therefore, potential for the current interconnection charges to produce excessively strong signals for peak-time load reduction, especially in the UNI and USI. This would

[76] However, the RCPD allocation is less effective than might be hoped, because distributors are able to pass through transmission costs to retailers or end consumers, and so need not respond to RCPD signals.

[77] Deadweight loss is the inefficiency caused by, for example, a tax or monopoly pricing. A deadweight loss is a loss of economic efficiency that can occur when equilibrium for a good or service is not Pareto optimal. In other words, either people who would have more marginal benefit than marginal cost are not buying the product, or people who have more marginal cost than marginal benefit are buying the product.

lead to (for example) inefficiently high amounts of new embedded generation, back-up generation capacity or demand-side management. Such outcomes have not been observed to date but could plausibly arise in the medium term.

4.4.16 These costs are partly countered by benefits in the millions of dollars (NPV) in the short to medium term, and potentially substantially more in the longer term. These benefits arise through the RCPD charge, which helps to incentivise an efficient combination of generation, transmission and demand-side investment in the UNI, and possibly (subject to medium-term uncertainty) in the USI as well.

4.4.17 A summary of the costs and benefits of the interconnection charge is provided in Table 3:

Table 3: Summary of costs and benefits of interconnection charge

Efficiency impact	Benefit or cost	Point estimate	Range, where applicable
Inefficient transmission investment decision making, relative to beneficiaries pay charge	cost	($22M)	($0) – ($72M)
Lack of incentive to change generation investment to defer export-driven transmission investment, where it is efficient to do so, relative to beneficiaries pay charge	cost	($25M)	($12M) – ($50M)
Lack of incentive to change generation and demand-side investment and operation to defer import-driven transmission investment, where it is efficient to do so, relative to beneficiaries pay charge	cost	($20M)	($0) – ($48M)
Total cost relative to beneficiaries pay charge		($67M)	($12M) – ($170M)
Inefficient incentive for major LNI consumers to shift demand out of RCPD periods	cost	($5M)	
Potential for excessive incentive for peak load reduction, embedded generation, etc., especially in USI, UNI, because of	cost	Medium to long term: Unquantified	

Efficiency impact	**Benefit or cost**	**Point estimate**	**Range, where applicable**
large increase in interconnection charges			
Deadweight loss from inefficient incentives on mass-market consumers to reduce demand	cost	($30M)	
Total cost		At least ($102~~69~~M)	At least ($47M) – ($205M)
Incentives for efficient combination of transmission, generation and demand in UNI and possibly USI	benefit	Short to medium term: Millions of dollars (Unquantified) Longer term: Potentially substantially more	
Total		**Uncertain (likely cost)**	

Q12.	**What comments do you have about:**
a.	**the differences (including their materiality) between private benefits from interconnection assets and interconnection charges; and**
b.	**The consequences of those material differences?**
Q13.	**What comments do you have about the Authority's analysis of the problems with interconnection charges?**
Q14.	**Do you consider that there are any other problems with the interconnection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem.**

4.5 Problems with recovery of the cost of network reactive support assets

4.5.1 Most of the New Zealand power system is an alternating current (AC) network. Elements of AC systems generate and consume two kinds of power: real power and reactive power. Real power provides heat, light and motive power. Reactive power supports the voltage and is essential for reliably operating the system.

4.5.2 The transmission network requires reactive support equipment at different places in the system to compensate for reactive power generated or consumed and to carefully control the levels to avoid power cuts in the event of unexpected system events. Controlling reactive power flows help avoid voltage collapse following events, reduce losses, and, in some cases, alleviate transmission constraints.

4.5.3 There are two broad types of reactive support needed by the New Zealand power system.

(a) Static reactive support relates to steady state voltage management and provides support to compensate for on-going reactive power issues. For example, switching capacitor banks or dispatch of generator reactive capability to maintain normal voltage levels. This type of reactive support can respond to change in the power system, but on a daily rather than millisecond basis.

(b) Dynamic reactive support maintains voltage within acceptable limits in the milliseconds following unexpected outages and helps avoid widespread loss of supply. It is provided by fast acting generator reactive capability or static var compensators (SVCs) for example.

4.5.4 Generally, investment in dynamic reactive support is more costly than investment in static reactive support. Both the fixed and variable costs of producing static reactive power are much lower than those of producing dynamic reactive power. However, the reactive power capability from a dynamic source can be adjusted much more quickly.

Static reactive support

4.5.5 The costs of interconnection assets that provide static NRS[78] are currently recovered in the same way as other interconnection assets – i.e. through the interconnection charge paid by off-take customers, using the RCPD cost allocation methodology. However, there are clearly identifiable exacerbators whose activity leads to the need for static NRS grid investments – these are the parties that cause reactive power off-take at times of system peak loading in both the UNI and USI regions.[79]

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78 These assets are most commonly switched static capacitor banks, which inject a fixed level of reactive power into the grid when switched on. They are needed in regions where relatively little generating capacity is connected. Generators normally provide the reactive power needed to maintain healthy grid voltage levels.

79 The LNI and LSI regions do not in general face the same issue as there is generally a satisfactory reactive power supply/demand balance in those regions without the need for additional investment in grid NRS assets.

4.5.6 Problems with power factor[80] management arrangements under the Code were explored by the TPAG.[81] Problems identified include:

(a) off-take customers cannot practically comply with the current Connection Code unity power factor requirement in the UNI and USI regions at reasonable cost;

(b) Transpower cannot practically enforce breaches by off-take customers of the power factor requirements in the Connection Code; and

(c) the attempt to minimise Transpower's expenditure on static NRS – by requiring off-take customers to efficiently invest (and incentivise their customers to efficiently invest) in their own reactive power compensation measures so that Transpower's investment is not required – is inconsistent with promoting the efficient level of investment by Transpower in such equipment (which is non-zero).

4.5.7 The parties that exacerbate the need for static NRS investments (i.e. off-take customers in the UNI and USI regions) cause costs of between $1.5 million and $2 million a year because they do not face the full cost of those investments by Transpower. Consequently, they lack the right incentives to make efficient decisions. If these parties faced the full cost of static NRS investments by Transpower they would have efficient incentives to choose to either:

(a) supply their own reactive power demand at times of grid peak loading, including the demand of their own customers; or

(b) have Transpower supply reactive power from grid connected NRS equipment.

Dynamic reactive support

4.5.8 Dynamic reactive support is currently procured by the system operator. The system operator voltage support procurement costs are recovered under Part 8 of the Code:

(a) from distributors and direct connect customers through a peak reactive power demand charging regime; and

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[80] Reactive power (supporting voltage levels) in relation to active power (providing useful power to a load) is measured by 'power factor' (pf). Unity power factor (pf = 1.0) indicates no reactive power flow as a proportion of active power flow into a load (i.e. all power flowing is active power). Increasingly 'lagging' power factor (i.e. pf = 0.99, 0.98, 0.97 and so on) indicates increasing amounts of reactive power flow into a load as a portion of active power.

[81] TPAG report, section 7.

(b) from non-compliant generators (those that cannot meet their Asset Owner Performance Obligations (AOPOs)[82] who have entered into an equivalence arrangement).

4.5.9 However, this approach has been seen as an interim measure until Transpower develops capability to supply dynamic support beyond that which can be provided by generators, such as by constructing the static var compensator being located at Marsden. Under the current TPM, the costs of dynamic reactive support assets provided by Transpower are recovered through the interconnection charge.

4.5.10 In principle, an exacerbators-pay charge could be an efficient charge on dynamic reactive support as some dynamic reactive support is provided to address an externality – management of voltage instability caused by some specific parties. However, an example of an event that would require dynamic reactive support to manage voltage instability is a helicopter flying into a transmission line. While the helicopter operator would be the exacerbator in this example, it is unlikely to be efficient to apply an exacerbators-pay charge in such a case (assuming the helicopter operator was a market participant).

4.5.11 In addition, dynamic reactive support reduces transmission losses, which enables greater power transfer into a region. Accordingly, it may be efficient to charge the parties benefiting from the greater power transfer enabled by dynamic reactive support through market, market-like, or beneficiaries-pay charges.

4.5.12 Transpower's recovery of its costs of providing dynamic reactive support assets through the interconnection charge is inconsistent with market, market-like or beneficiaries-pay (or exacerbators-pay) charging since the costs are recovered from all off-take customers, who pay interconnection charges, rather than beneficiaries (or exacerbators). As a result, beneficiaries (and, where it would be efficient, exacerbators) lack incentives to take into account the costs of dynamic reactive support in their investment decisions.

[82] AOPOs require that generators must be capable of importing and exporting specified quantities of reactive power over specified voltage ranges.

4.6 Problems with the prudent discount policy and inefficient disconnection

4.6.1 The current PDP exists to mitigate the extent to which the current TPM contains pricing signals that inefficiently incentivise the bypass of grid assets.

4.6.2 The starting point for a review of the PDP is to reflect that it is an alternative charging option. As such, the Authority's economic framework suggests that where the PDP is applied there may be more efficient charging methods available, namely market, market-like, exacerbators pay or beneficiaries pay charging options.

4.6.3 The origins of the PDP are as a commercial pricing response by Transpower that sought to mitigate an unintended consequence of early TPMs that, in some circumstances, had the effect of incentivising grid users to inefficiently bypass existing grid assets with their own transmission investments.[83] However, the Authority considers that the purpose of the PDP should be to recover Transpower's maximum allowable revenue (MAR) as efficiently as possible.

4.6.4 Transpower has advised that two new prudent discount agreements have been entered into since the current TPM was introduced in 2008. No cases of actual inefficient bypass of existing grid assets have been cited by submitters in recent TPM consultations. Thus, the current PDP would appear to be effective because uneconomic alternative investments have not eventuated.

4.6.5 The key question is whether a PDP is needed in a potentially revised TPM.[84]

4.6.6 Granting a prudent discount involves making a judgement that inefficient bypass would actually otherwise occur. Applicants are highly incentivised to overstate benefits and underplay real costs, risks and implementation barriers. This, in addition to the fact that Transpower is able to recover from other transmission customers the revenue forgone from prudent discounts, leads to a conclusion that prudent discounts *may* have been

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[83] Further background and discussion of this issue was provided in section 2.5 of the February 2012 consultation paper on the decision-making and economic framework for the TPM review. Refer *Transmission pricing methodology decision-making framework – consultation paper*, 26 January 2012.

[84] The Authority notes from information provided by Transpower that a number of current prudent discount agreements (entered into under the arrangements for notional embedding arrangements, which preceded prudent discount agreements) are due to expire in coming years; one is under current renegotiation.

granted in some early cases where actual bypass would not have in fact eventuated.[85]

4.6.7 Transpower noted in its submission on the decision-making and economic framework consultation paper that the current process for making a PDP application sets a very high bar, requiring applicants to establish that an uneconomic alternative investment actually exists and would very likely be implemented if a prudent discount were not granted. If the bar were set too high, or if valid applications had been declined, the Authority would expect that some uneconomic bypass would have occurred. However, there is no evidence that this has been the case.

4.6.8 The Authority considers that a prudent discount measure *may* be necessary in future but in any revised TPM should only be considered alongside the design of individual pricing components. Accordingly, the appropriate design for the PDP is discussed in chapter 5 after considering specific options for other price components.

Q15. What comments do you have about the Authority's view that a prudent discount policy may be necessary after taking into account the incentives provided by the price components of any revised TPM?

[85] If a prudent discount is granted, for the term of the prudent discount agreement, the beneficiaries are *guaranteed* that the allowed net present value of the contract will accrue to them. All of their alternative investment risks are thereby mitigated.

5. Proposed amendments to the TPM

Key points

The Authority's proposal has been developed following consideration of a range of options and involves a package of charging approaches. The Authority considers the proposal is lawful, practicable and will recover transmission costs while facilitating efficient investment in the electricity industry and efficient operation of the grid, generation, distribution and demand-side management.

Use of LSE to offset transmission charges

The Authority proposes to codify the current arrangements where surplus loss and constraint excess (and in the future, surplus financial transmission right auction proceeds) received by Transpower from the clearing manager are to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals. This is a **market approach**. This would apply to all assets on which loss and constraint excess arises.

Recovering the costs of connection services

The Authority proposes retaining the status quo for recovering the costs of connection services, except to add new rules to limit the shifting of connection costs into the interconnection charge. This approach would retain and improve the market-like arrangements for connection services. The proposal is:

a) for the TPM to require that current connection assets be treated as connection assets until they are replaced or decommissioned;

b) for the TPM to require that replacement assets are valued for charging purposes at the actual replacement project cost; and

c) for the Benchmark Agreement to include a mechanism to refer to the Authority disputes between Transpower and a connecting party about the level of connection charges following connection asset replacement.

Recovering the costs of static reactive support services

The Authority proposes to establish a specific exacerbators-pay charge to recover the costs of static reactive support services. The proposal is:

a) for the TPM to include a kvar charge based on the aggregate kvar draw of off-take transmission customers, at times of regional coincident peak demand, in areas of the grid where investment in static reactive support is likely to be required; and

b) to set the kvar charge at the long run marginal cost of grid-connected static reactive support investment.

The Authority also proposes that the Connection Code set a minimum power factor of 0.95 lagging for all regions.

The proposal will provide parties with incentives to draw reactive power only when and where this is efficient or to invest in equipment to manage their reactive power use.

Although some dynamic reactive support is provided to address some externalities it does not appear to be practicable to apply an exacerbators-pay charge to recover those costs. Moreover, dynamic reactive support can also provide benefits to parties by enabling greater power transfer into a region. The Authority proposes that the costs of dynamic reactive support will be recovered using the proposed arrangements for charging for other interconnection assets.

Recovering the costs of HVDC and interconnection services
The Authority's proposal for recovering the costs of HVDC and interconnection services has four parts:

a) Part 1: As noted above, to codify the current arrangements where surplus loss and constraint rentals received by Transpower from the clearing manager are to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals.

b) Part 2: for the TPM to require the SPD (or vSPD) model to be used to (1) identify the beneficiaries of certain HVDC and interconnection investments and (2) estimate the extent of the private benefits they receive from those investments on a half-hourly basis (referred to as the SPD method). The beneficiaries identified by this method would be charged for the cost of each investment in proportion to their share of the benefits of each investment, but with the amount of this part of the charge not exceeding their private benefit in each case. This is a **beneficiaries-pay charging approach**. The approach would apply for assets of more than $2 million approved after 28 May 2004 and pole 2 of the HVDC link.

c) Part 3: for the TPM to require Transpower to apply a regional coincident peak demand (RCPD) charge to load and regional coincident peak injection (RCPI) charge to generation parties to recover the residual balance of the costs of the HVDC and interconnection assets not recovered by other charges. The RCPD and RCPI charges should be set so that each raises half the residual balance. They should also be designed so that parties subject to the charge have efficient incentives to avoid peak use of the grid in the region in which they are located. This is an **alternative charging approach**.

d) Part 4: to refine the current PDP to enable Transpower to more efficiently deal with the possibility of inefficient bypass of the grid and inefficient disconnection from the grid.

Cost-benefit analysis of Authority's proposal
The Authority estimates that the overall TPM proposal would deliver net economic benefits compared to the current TPM of $173.2 million (net present value). By comparison, the option preferred by the majority of the TPAG is estimated to deliver net benefits of $49.3 million. The Authority's proposal is expected to cost $5.6 million to design and implement, with on-going operating costs estimated to have a present value of $44.5 million.

5.1 Introduction

5.1.1 This chapter presents the Authority's proposals for recovering Transpower's costs of providing:

(a) connection services (see section 5.3);

(b) network reactive support services (section 5.4), which is a subset of both HVDC and interconnection services; and

(c) all other HVDC and interconnection services (section 5.5).

5.1.2 This chapter also explains the Authority's proposals to refine prudent discount arrangements to address the potential for uneconomic bypass of interconnection services and uneconomic disconnection from interconnection assets. These issues are considered in section 5.5.

5.1.3 The Authority's proposals for recovering Transpower's costs of providing transmission services will require amendments to the Code, in particular to the TPM (a schedule to the Code). The Authority will consult on proposed amendments to the Code once Transpower submits a proposed TPM developed in accordance with the guidelines and the process determined by the Authority.

5.1.4 However, given that such consultation must meet the requirements of the Act, and that, depending on the nature of submissions, the proposals in this paper are intended to form the basis of the Code amendments, the Authority has set out its analysis in a way that is consistent with the requirements of section 39 of the Act.

5.1.5 In particular, section 39(1) of the Act requires the Authority to prepare, publicise, and consult on a regulatory statement relating to a proposed Code amendment. Under section 39(2), the regulatory statement must include:

(a) an evaluation of the costs and benefits of the proposed amendment – this is provided in section 5.6; and

(b) an evaluation of alternative means of achieving the objectives of the proposed amendment – this is provided in Appendix F and summarised in chapter 6.

5.1.6 Section 39(2) of the Act also requires the regulatory statement to contain a statement of the objectives of the proposed amendment. The Authority's overall objective in proposing amendments to the TPM is provided in paragraph 3.2.2. Section 5.7 assesses the Authority's proposals in regard to this objective.

5.2 Overview of options for recovering transmission costs

5.2.1 The Authority has applied the hierarchy of approaches outlined in the Authority's Decision Making and Economic Framework for Transmission Pricing paper.[86] The hierarchy consists of approaches based on:

(a) market; then

(b) market-like; then

(c) exacerbators pay; then

(d) beneficiaries pay; and then

(e) alternative charging options, i.e. charges that seek to minimise inefficiencies from the charge but enable Transpower to recover its maximum allowable revenue.

5.2.2 The Authority has considered a range of options and assessed whether they are lawful (including whether they would recover transmission costs), practicable, and the extent to which they improve efficiency.

5.2.3 The Authority has identified that connection charging arrangements are a market-like approach and are generally efficient. However there are some relatively minor drafting deficiencies (loopholes) in the current TPM that could inefficiently permit shifting of connection costs into the interconnection charge. This chapter proposes amending the TPM to close those loopholes.

5.2.4 The Authority identified in Chapter 4 that the current HVDC and the interconnection charges are not efficient. Accordingly, the Authority considers it appropriate to examine options for recovering the costs of such assets.

5.2.5 Current wholesale market arrangements provide a market approach for paying for connection, HVDC and interconnection services. This occurs in the form of loss and constraint rentals (referred to as loss and constraint excess (LCE) in the Code) which arise from the difference between the amount paid to generators for wholesale electricity and the amount paid by purchasers for wholesale electricity due to transmission losses and constraints.[87] Transpower allocates loss and constraint rentals to

[86] Electricity Authority, January 2012, Decision-making and economic framework for transmission pricing methodology consultation paper, available at, http://www.ea.govt.nz/document/16502/download/our-work/programmes/priority-projects/transmission-pricing-review/.

[87] Loss and constraint excess or rentals result from price differences between two nodes due to:

transmission customers who can use the LCE they receive to offset their transmission charges. Similarly, Transpower will allocate surplus revenue from FTR auctions to transmission customers who can use this to offset their transmission charges.[88] The revenue available from loss and constraint rentals is considerably less than Transpower's revenue requirements, requiring a large residual to be recovered through direct charges for transmission.

5.2.6 The Authority has found that other market-based or market-like charging options for recovering HVDC and interconnection costs are either not lawful, not practicable or inefficient. For completeness, chapter 6 considers the following market or market-like options for recovering HVDC and interconnection costs:

(a) long-term contracts;

(b) capacity rights or offer rights;

(c) long-term contracts with capacity rights;

(d) merchant transmission investment; and

(e) vote-based transmission investment.

5.2.7 The Authority has identified a single situation where an exacerbators-pay charging option could apply – there are clearly identifiable parties that, by their actions or inaction, cause reactive power off-take demand at times of system peak, thereby requiring investment in static network reactive support assets. Section 5.4 presents the Authority's proposals for introducing an exacerbators-pay option - a kvar charge - to recover the costs of static network reactive support assets.

5.2.8 The Authority has identified beneficiaries-pay options for recovering all other HVDC and interconnection costs (including dynamic network reactive support costs) that are lawful, practicable, and deliver efficiency gains. These options are:

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a) losses – this refers to the loss of electricity as heat when electricity flows across the grid from where it is generated to where it is consumed; and

b) constraints – a limitation in the capacity of the grid to convey electricity demanded caused by limitations in the capability of available assets or limitations in the performance of the grid. As a result, the electricity demanded must be supplied by more expensive sources of generation closer to the points of demand.

[88] When the inter-island FTR is in place loss and constraint rentals resulting from price differences between Benmore and Otahuhu will not be available to reduce transmission charges as these rentals will be used to fund inter-island FTRs. However, inter-island FTR will be allocated by auction, so FTR auction proceeds would be available to reduce transmission charges.

(a) using a wholesale electricity market model – such as the scheduling, pricing and dispatch (SPD) model or vectorised SPD (vSPD[89]) model – to apply the beneficiaries-pay approach on a nodal basis;

(b) using an economic model to apply beneficiaries pay on a nodal basis;

(c) using flow tracing to apply beneficiaries pay on a nodal basis; and

(d) zonal beneficiaries pay.

5.2.9 The Authority is proposing the SPD or vSPD model be used first to identify beneficiaries of certain HVDC and interconnection investments, and second to estimate the extent of the private benefits those parties receive from those investments on a half-hourly basis. The beneficiaries identified by this method would be charged for the cost of each investment in proportion to their share of the benefits of each investment, but with their maximum charge not exceeding their private benefit in each case.

5.2.10 The Authority considers that the approach it favours in relation to charging for the interconnected grid avoids the need for separate and special treatment of 'but for' interconnection assets. Connected parties that benefit from the provision of certain interconnected assets will be identified in the normal operation of the Authority's proposed methodology and charged for these assets on a basis commensurate with the benefits they derive from them. The need to separately or specially deal with, so called, 'but for' interconnection assets will be avoided, along with the practical difficulties this would involve.

5.2.11 Applying beneficiaries-pay methods to all HVDC and interconnection assets is not practicable, and some investments may generate insufficient private benefits in their early years in order to recover their annualised costs in those years. Also, some investments may be uneconomic in that they do not produce net economic benefits over time, and so would never produce sufficient private benefits to enable full cost recovery using a beneficiaries-pay charge.

5.2.12 The Authority has identified the following alternative charging options for recovering transmission costs not recovered through the above beneficiaries-pay charge (referred to as a residual charge):

(a) RCPD charge on load and RCPI charge on generators designed to provide efficient signals about peak transmission capacity;

[89] vSPD is a vectorised version of SPD, the market clearing engine used in the New Zealand electricity market, and was developed by the Authority to replicate the schedules, prices and dispatches produced by SPD. For further information see: http://www.ea.govt.nz/industry/monitoring/models-and-tools/vspd/.

(b) current RCPD charge;

(c) MWh charge; and

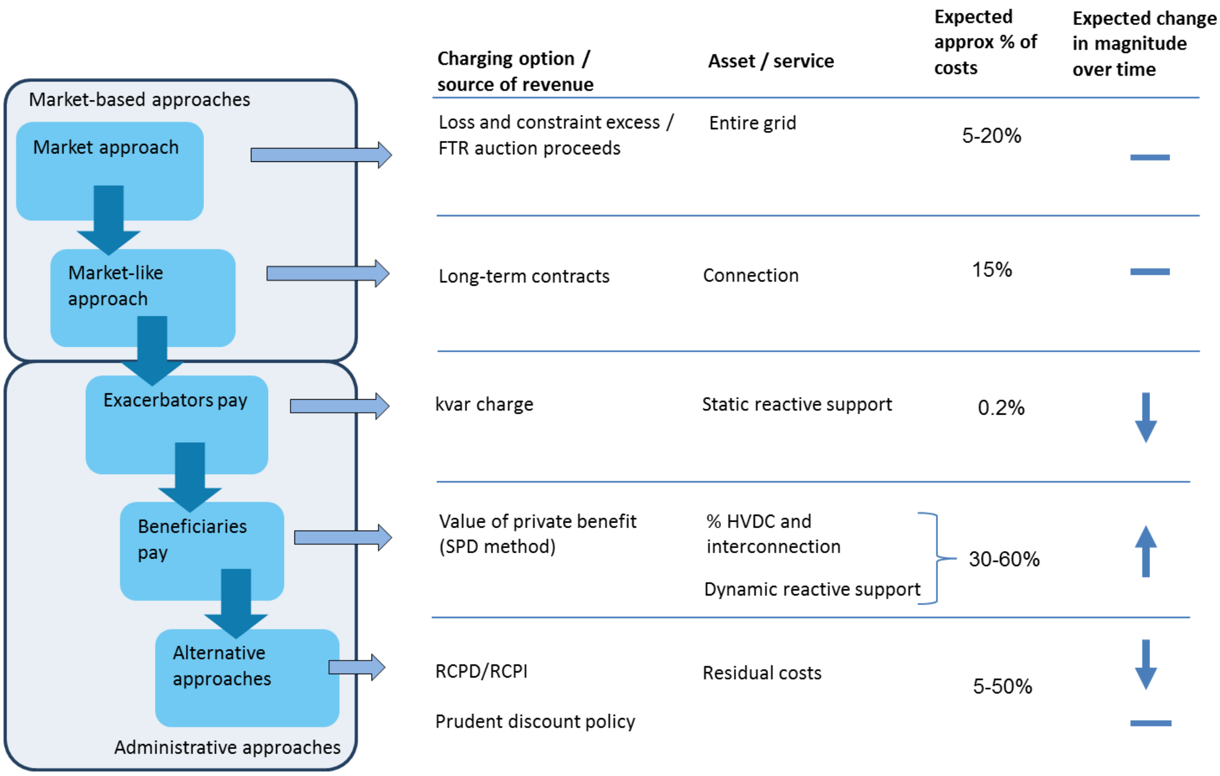
(d) incentive-free MWh charge.

5.2.13 The Authority considers that the residual charge should, in effect, consist of two charges: a regional coincident peak demand (RCPD) charge on load and a region coincident peak injection (RCPI) charge on generation, which should be designed to encourage efficient avoidance of peak regional use of the grid. Further, these charges should be designed so that half the residual is borne by load (direct connected customers, distributors and potentially retailers) and half is borne by generators. This includes generators, direct connect customers, distributors, and, potentially, retailers. The Authority considers that distributors could be given the ability to opt out of the residual charge and transfer the obligation to the retailers, except to the extent the distributor benefits from participation in the wholesale market. A distributor would be able to opt out only after consulting with retailers connected to the distributor's network.

5.2.14 Finally, the Authority's assessment is that a prudent discount policy (PDP) serves a useful backstop role for dealing with specific circumstances where inefficient bypass or inefficient disconnection may occur due to the residual charge.

5.2.15 The Authority's overall proposal, including an explanation of how each element relates to the Authority's economic framework for the TPM, is summarised in Figure 6.

Figure 6: Overview of proposal and relationship of each option to economic framework



5.2.16 Table 4 provides an overview of the Authority's assessment of each option for recovering HVDC and interconnection costs (other than the costs of grid reactive support and the PDP). The detailed analysis underpinning this assessment is provided in section 5.5 and chapter 6. Note the options in the Authority's proposal are highlighted in bold.

Table 4: Overview of options to recover HVDC and interconnection costs

Option	Section	Nature of option	Lawful	Practicable	Efficient	Potential to recover costs
Long-term contracts	6.3	Market	Y	N	✓	Partially
Capacity rights or offer rights	6.3	Market	Y	N	✓	Partially
Merchant transmission	6.3	Market	N	Y	✓✓✓	Partially (new)

Option	Section	Nature of option	Lawful	Practicable	Efficient	Potential to recover costs
investment						
Vote-based transmission investment	6.3	Market-like	N	Y	✓✓	Partially (new)
Wholesale market model (SPD/vSPD)	5.5	Beneficiaries pay	Y	Y	✓✓✓	Yes
Economic model	6.5	Beneficiaries pay	Y	Y	✓✓	Depends on whether investments are efficient
Flow tracing	6.5	Beneficiaries pay	Y	N	✓	Depends on whether investments are efficient
Zonal uniform charge	6.5	Beneficiaries pay	Y	Y	✓	Depends on whether investments are efficient
Current RCPD charge	6.6	Alternative	Y	Y	✓	Yes
RCPD/RCPI charge	5.5	Alternative	Y	Y	✓✓	Yes
MWh charge	6.6	Alternative	Y	Y	✓✓	Yes
Incentive-free	6.6	Alternative	Depends	N	✓	Yes

5.3 Proposal to codify current arrangements for the treatment of loss and constraint rentals

5.3.1 The Code[90] requires the clearing manager to pay to Transpower loss and constraint excess (LCE) and residual LCE (the surplus revenue that the clearing manager holds after settling FTRs[91]). The Code requires Transpower to treat residual LCE as LCE. [92] In this paper LCE and residual LCE are referred to together as LCE, unless the context requires another interpretation.

5.3.2 The Code is silent on how Transpower applies the LCE and residual LCE received from the clearing manager. However, clause 45.1 of Part D of the Benchmark Agreement states that Transpower will calculate, in accordance with the *prevailing methodology* for distribution of LCE, the share of LCE (net of any GST received) to be allocated to each transmission customer (which would offset their transmission charge). In other words, the Benchmark Agreement assumes that Transpower has a methodology for allocating LCE to transmission customers, but does not specify how or to whom the LCE is allocated.

5.3.3 Transpower's current allocation methodology[93] involves allocating LCE to customers that pay for assets in each of three classes: AC connection assets (ACC), AC interconnection assets (ACI), and DC assets. Transpower does this by classifying each transmission arc into one of the three asset classes. The electricity flow across each arc is then multiplied by the price difference across the arc, and the amounts are summed for each of the three asset classes to give monthly "rental guides".

5.3.4 These guides determine the proportions in which the LCE is allocated to the three asset classes. The LCE can be greater or less than the sum of the monthly rental guides due to factors such as wash-ups. Once the LCE received is allocated to the three asset classes, the LCE is rebated to customers, broadly speaking, in proportion to customers' transmission charges in that asset class.

5.3.5 The Authority and its service providers are currently in the process of implementing a FTR market, in which FTRs are initially auctioned by the

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90 Clause 14.73(4) of the Code.

91 Residual LCE may include FTR auction revenue, though this depends on the outcome of the FTR market and whether auction revenue is required to settle FTRs.

92 Clause 14.73(5) of the Code.

93 Refer Transpower, *Transmission rentals (Losses and constraints excess payments),* March 2008. Available at: https://www.transpower.co.nz/sites/default/files/publications/resources/transmission-rentals-2008.pdf.

FTR manager and secondary trades can subsequently occur. The distinguishing feature of FTRs is that they use LCE to provide (relatively) firm hedges against basis risk in the spot market. In principle, the auction proceeds from FTRs should over time equal the present value of the loss and constraint rentals used to fund FTRs. The current intention is for surplus FTR revenue to be paid to Transpower, who would allocate this to its transmission customers. The allocation would be on the same basis as for LCE, with the amount of LCE allocated to each asset class determined by the monthly rental guides, and the allocation to each customer in proportion to the customer's transmission charges in that asset class. It is expected that Transpower will, on average, have the same amount of revenue available to allocate as at present. This would offset the transmission charges of transmission customers in the same way that the current allocation of LCE does.

5.3.6 The Authority proposes to codify that LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origin of the rentals. This clarifies that the revenue to be recovered from transmission customers is net of any LCE received and apportioned to a particular asset. However, the proposal does not require specifying in the Code the particular methodology that Transpower uses to apportion LCE to particular assets. Rather, the Code could require that Transpower's methodology for applying LCE to particular assets must have the purpose of offsetting transmission charges to the customers of those assets.

5.3.7 The approach does not prevent the Authority proposing to use some or all of the LCE or residual LCE for another purpose. This is because this requirement would just apply to the LCE and residual LCE that Transpower receives from the clearing manager. This means that this requirement does not prevent the introduction of, for example, FTRs or locational rental allocations (LRAs) to manage intra-island locational price risk.

Lawfulness

5.3.8 The proposal to require through the Code that LCE and residual LCE received by Transpower are applied to offset transmission charges is lawful.

Practicability

5.3.9 This proposal codifies existing practice so would be straightforward to implement.

Assessment of costs and benefits of part 1 of proposal

5.3.10 Overall, this proposal will promote a more efficient TPM.

5.3.11 The benefits of this option are that it:

(a) promotes efficient investment by generation and load through providing certainty to transmission customers that LCE and residual LCE received by Transpower is to be used to offset transmission charges;

(b) promotes allocative efficiency through more efficient prices by reducing deadweight loss, as using LCE and residual LCE reduces the amount of revenue that must be recovered using less efficient approaches; and

(c) promotes durability by promoting a more certain transmission pricing regime. This will reduce on-going lobbying for a change to the TPM which will result in savings in expert legal and technical/economic resources and reduce uncertainty.

5.3.12 The likely costs of this option are:

(a) costs to the Authority and participants of amending the Code; and

(b) risk that codification of this requirement will result in a loss of flexibility to determine the most efficient use of transmission rentals. However, since the proposal is to codify only Transpower's broad approach to use of LCE to offset transmission charges rather than the specific methodology, this risk is expected to be minor.

5.3.13 The main disadvantage of this approach is the minor risk of a loss of flexibility in the use of LCE but the Authority considers that this risk is manageable.

Potential to recover transmission costs

5.3.14 It is expected that LCE and residual LCE will cover only a proportion of costs. Since 1997, total transmission rentals have ranged from around \$40m per annum to around \$200m per annum, and total transmission annual costs are projected to increase from around \$800m in 2014/2015 to over a \$1.1b by 2020/2021. Therefore it is likely that at least around 75% of these costs would need to be funded by other means.

Q16. What is your position on the Authority's proposal to codify that LCE or residual LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals?

5.4 Proposal to recover the cost of connection services

5.4.1 The Authority considers the current market-like charging arrangements for connection are generally efficient, and therefore proposes to retain the essential components of the current charging approach. However, as identified in Chapter 4, there are minor aspects of the connection charging arrangements that provide inefficient incentives for parties to shift some connection costs into the interconnection charge.

5.4.2 The Authority has considered two options for dealing with these inefficiencies:

(a) retain the status quo, which involves leaving it to Transpower to negotiate contracts that recover the full economic costs of connection investments; or

(b) make minor amendments to the TPM to correct drafting deficiencies (loopholes).

5.4.3 The Authority proposes that the TPM is amended as specified below, and refers readers to section 6.2 for an evaluation of the option to retain the status quo.

Proposal: amend the TPM to restrict the shifting of connection costs into the interconnection charge

5.4.4 The problems identified with connection charging arrangements reflect relatively minor loopholes in the current TPM. The most direct mechanism to remedy these issues is to amend the TPM to close the loopholes. This approach would retain and improve the market-like arrangements for connection services.

5.4.5 The problem of reclassification at the boundary of connection and interconnection would require a new provision that applied when considering connection investments that would inadvertently redefine existing connection assets as interconnection assets. There are several approaches to do this but the most direct approach is to include a provision that requires that current connection assets remain defined as connection assets until they are eventually replaced (at which point a new investment agreement would be required) or decommissioned.

5.4.6 If this provision is considered likely to result in unintended outcomes, then a referral provision could be included that allowed the Authority to consider and rule on a proposed reclassification of connection assets as interconnection assets.

5.4.7 Similarly, the connection asset replacement hold-out problem could be addressed by adding a new requirement in the TPM that replacement assets are valued for charging purposes at the actual replacement project cost. If considered necessary, the proposed referral provision could be included in the Benchmark agreement to allow a connection customer to dispute any connection charges they considered had been set at an unreasonable level as a result of asset replacement.[94] Where the Authority considered that changes were required to the charges applying to the customer, a mechanism would be required to ensure that charges were allocated in accordance with the Authority's determination. The Authority proposes this would be developed by Transpower.

5.4.8 This option otherwise retains the current provisions for establishing connection charges, which are generally well understood, effective and efficient.

5.4.9 In summary, the proposal is to:

(a) add a provision to the TPM that requires current connection assets to be treated as connection assets until they are eventually replaced or decommissioned;

(b) add a new provision that replacement assets are valued for charging purposes at the actual replacement project cost; and

(c) add referral provisions to allow the Authority to deal with special cases or to allow a connection customer to dispute connection charges they considered had been set at an unreasonable level as a result of asset replacement. This would include a mechanism to deal with any changes required to transmission charges as a result of the Authority's determination.

Lawfulness of closing loopholes

5.4.10 The proposed minor redrafting of the existing connection charging arrangements is lawful.

Practicability of closing loopholes

5.4.11 The Authority considers the proposed minor redrafting of the existing connection charging arrangements is practicable and the overall connection charging regime would remain practicable.

Assessment of costs and benefits of closing loopholes

5.4.12 The Authority considers that the benefits of closing loopholes to prevent the shifting of connection costs into the interconnection charge are:

(a) <u>More efficient investment in connection assets.</u> Connection customers will consider the full cost implications of investments undertaken for their private benefit, meaning that investment by Transpower in new and

[94] This would only occur where Transpower initiated the replacement of connection assets under a grid upgrade plan, which could occur if Transpower and the connection customer are unable to agree a new investment contract covering the same asset replacement.

replacement connection assets should only occur where the private benefits exceed the private costs. This should encourage more efficient investment decisions as the private benefits and costs of connection services should reflect the social benefits and costs of those services.

(b) More efficient prices for transmission customers paying for the core grid. The corresponding reduction in interconnection charges should reduce any inefficiencies associated with those charges.

(c) Reduced transaction costs. Relative to the status quo, the transaction costs of negotiating agreements to provide new and replacement connection assets should be reduced because the full cost recovery principle and relevant TPM provisions are clarified, reducing the opportunity for connection parties to game the connection charging regime. Further, the overall TPM should become more stable, as parties will not have grounds to quibble about inappropriate cost shifting to those paying interconnection charges.

5.4.13 The Authority considers that the costs of this option are relatively minor because implementation involves drafting amendments to the Code only to clarify the intended economic principles and any (likely minimal) costs involved in referring a dispute to the Authority. Because these costs are likely to be minimal they are not included in the cost-benefit analysis summarised in section 5.7 and set out in detail in Appendix F.

5.4.14 The Authority considers that the benefits would exceed the costs by removing some unintended consequences from the existing TPM without affecting the balance of the connection charge methodology or the provisions relating to investment contracts, which are generally working well. This approach does not prevent the Authority applying a beneficiaries-pay charge to recover costs from assets in the interconnected grid from connection customers where they obtain private benefits from these assets.

Potential to recover connection costs by closing loopholes

5.4.15 The Authority considers that the proposal would enable Transpower to recover the economic costs of connection services from the party or parties benefiting from the connection investment.

Q17. Do you agree there would be efficiency gains from each of the components of the proposal for the connection charge, as outlined in paragraph 5.4.9? Please provide an explanation for your answer.

Q18. Do you agree that the proposal will address the problem identified in chapter 4 in relation to the connection charge? Please give reasons for your views.

5.5 Proposal to recover the costs of network reactive support services

Introduction

5.5.1 The Authority considers that investments in static network reactive support to improve voltage management and power quality may have a primary purpose of mitigating externalities. By making the transmission system more robust to contingent events dynamic network reactive support may also have a purpose of mitigating externalities but also provides benefits from enabling greater power transfer into a region. The costs of such investments are a subset of both HVDC and interconnection costs.

5.5.2 Chapter 4 identified that Transpower invests in network reactive support equipment to mitigate a low power factor in areas where users of transmission services have a high draw of reactive power.

5.5.3 Consequently, the Authority considers that the costs of providing static network reactive support should be recovered through an exacerbators-pay approach.

Proposal for static reactive support: kvar charge with minimum power factor

5.5.4 The Authority proposes the TPM be amended to allow Transpower to recover the costs of static reactive support by:

(a) introducing a kvar charge based on the average aggregate kvar draw of off-take transmission customers in areas of the grid where investment in static reactive support is likely to be required; and

(b) the kvar charge in (a) is to be set at the LRMC of grid-connected static reactive support investments and is to be applied at times of RCPD.

5.5.5 The Authority also proposes to set a minimum power factor of 0.95 lagging in the Connection Code for all regions.

5.5.6 The kvar charge is expected to provide a price signal to encourage off-take transmission customers (in areas where investment in static reactive support is likely to be required) to make efficient choices between:

(a) investing in distribution static reactive support equipment themselves;

(b) relying on Transpower to invest in grid static reactive support equipment; and

(c) encouraging or requiring their end-use customers to take steps to improve any poor power factor within their load.

5.5.7 The approach proposed is generally consistent with the recommendation of the TPAG to the Authority, but differs from the TPAG's recommendation in that Transpower, rather than the Authority, would develop the method for determining the LRMC of grid-connected static reactive support equipment. The Authority takes the view that Transpower is in a better position than the Authority to develop the method (which would be consulted on at the same time as a proposed TPM developed by Transpower).

5.5.8 Existing static reactive support assets that provide regional reactive power needs are currently incorporated within the interconnection asset base and their costs are recovered through the interconnection charge.

5.5.9 The Authority proposes that an approach similar to the current interconnection charge apply to the kvar charge and work as follows:

(a) Transpower determines the LRMC of nominal grid-connected static reactive support equipment, following the method it has prepared as part of the development of the TPM. This provides an efficient kvar charge rate and could, for example, be arrived at by dividing the estimated annual capital and operating costs of a new grid static reactive support asset (or group of assets) by the effective capacity the asset(s) would provide. Accordingly, the charge would not be linked to any specific existing grid static reactive support assets but would be reflective of Transpower's new investment and operating costs for grid static reactive support assets;

(b) Transpower uses the kvar demand data from the RCPD periods from the immediately preceding September-to-August period for capacity measurement. From this data, it assesses the average reactive power draw from the grid in kvar, for each off-take transmission customer in areas where investment in static reactive support is likely to be required. If an off-take transmission customer's net reactive power flow during the assessment period is 'negative' (i.e. reactive power is injected into the grid), the assessed quantity is set at zero and there will be no charge;

(c) Transpower calculates the expected revenue to be recovered from the kvar charge for the coming year by multiplying the result in subparagraph (a) by the sum of the off-take transmission customer results in subparagraph (b); and

(d) If the expected revenue in subparagraph (c) resulted in Transpower receiving more revenue than Transpower's MAR (the maximum revenue Transpower is able to earn as determined by the Commerce Commission) then other charges would be adjusted to ensure that Transpower's target revenue is the same as it would have been without the kvar charge.

5.5.10 The current year's kvar charge would be based on the immediately preceding year's kvar demand, using a similar approach to that used for the current interconnection charge. The benefit for an off-take transmission customer from decreasing its reactive power draw from the grid during the RCPD period is gained in the following year, since the impact of reduced reactive power draw is reflected in the following year's kvar charge.

5.5.11 A kvar charge based on the methodology outlined above is illustrated in Table 5.

Table 5: Amended kvar charge (indicative only)

	USI region	UNI region	Comment
LRMC of grid SRC equipment = kvar charge rate (per annum)	$4 – 5 /kvar	$4 – 5 /kvar	c.f. 2011/12 interconnection rate @ $76.14/kW
RCPD total reactive power demand	90 Mvar	285 Mvar	From 2010 RCPD data
kvar charge revenue (per annum)	$0.36 – 0.45m	$1.14 – 1.42m	
Illustrative reduction in current interconnection rate (due to revenue substitution to the kvar charge) if the interconnection charge remained unchanged	$0.26 – 0.32 /kW (= 0.34 – 0.42 %)		From 2011/12 TPM: Interconnection rate = $76.14 /kW Total RCPD = 5,872 MW

Lawfulness of the kvar charge

5.5.12 The kvar charge is lawful under the Code.

Practicability of kvar charge

5.5.13 A kvar charge to recover the costs of static reactive assets can be implemented under the Code. The key practical issues with the kvar charge are calculating and designing the rate to ensure consistent application over time.

5.5.14 Calculating the rate of the charge should be relatively straightforward since Transpower has ready access to information on costs of static reactive support equipment. The main issue will be determining how these costs may change over time, which will be required to determine the LRMC of this equipment.

5.5.15 Designing the kvar charge to ensure consistent application over time will require development of a method to ensure that the charge only applies when there is a risk that investment in static reactive support equipment may be required. This would require identification of a threshold or trigger that would mean that the charge would apply. Again this should be relatively straightforward – for example Transpower could include static reactive support equipment in the investment plan for a particular region.

Assessment of costs and benefits of kvar charge

5.5.16 In qualitative terms, the benefits of the kvar charge include:

(a) promoting efficient investment in static reactive support equipment in the transmission grid;

(b) promoting efficient investment in management of reactive power in distribution networks;

(c) promoting increased thermal capacity within regional distribution networks;

(d) providing incentives on direct connect transmission customers to take actions that would lower their kvar draw; and

(e) reducing any inefficiencies associated with the interconnection charge because network reactive support costs would be paid for by exacerbators rather than by all interconnection customers.

5.5.17 The costs of the kvar charge include:

(a) the costs for Transpower of developing and applying the kvar charge;

(b) the costs for transmission customers of complying with charge; and

(c) transaction costs involved in levying the charge.

5.5.18 The kvar charge would address a market failure (an externality – the need for investment in static reactive support equipment because of a high reactive power draw by some consumers), and cost-benefit analysis indicates that its implementation would provide net public benefits to consumers. In particular, the option should promote more efficient investment and management of grids and reduce grid losses for relatively low costs.

5.5.19 The Authority considered the TPAG quantitative assessment of the costs and benefits of a kvar charge for static reactive support and considers that the quantification of those costs and benefits remains robust.

5.5.20 The TPAG concluded that introducing a kvar charge for static reactive support is likely to provide a net public benefit of between $6 million and $26 million NPV resulting from off-take customers facing greater incentives to explore options for static reactive support or face the kvar charge.

5.5.21 The TPAG also concluded that increasing the power factor from 0.99 lagging to a unity power factor would provide a 1 per cent capacity increase. Using the ‘rule-of-thumb’ of $1 million/MW for grid augmentation this would result in:

(a) for the upper North Island, up to 20MW (1%) increase in capacity valued at a NPV of $20 million; and

(b) for the upper South Island, up to a 5MW (0.5%) increase in capacity valued at a NPV of $5m million.

5.5.22 Overall, the Authority considers that the kvar charge is likely to provide net benefits.

Potential to recover static reactive support costs

5.5.23 A kvar charge could readily be designed to cover all costs Transpower incurs in investing in static reactive support equipment to address high reactive power draw. An alternative charging mechanism would however be required to promote efficient investment in dynamic reactive support equipment.

Q19. What comments do you have about the Authority’s assessment and conclusions about a kvar charge to recover static reactive support costs?

Q20. Do you support:

a. introducing a kvar charge based on off-take transmission customers’ average aggregate kvar draw from the grid in areas where investment in static reactive support is likely to be required, at times of RCPD, at the long run marginal costs of grid-connected static reactive support investments?

b. setting a minimum power factor of 0.95 lagging in the Connection Code for all regions?

Q21.	**Do you consider that there are alternatives to a kvar charge for recovering the static reactive support costs that the Authority has not identified, and that are practicable, would deliver a net benefit and would recover static reactive support costs? Explain your proposal.**

Proposal for dynamic reactive support

5.5.24 The Authority proposes to charge for the costs of dynamic reactive support assets provided by Transpower using the beneficiaries pay charging method for HVDC and interconnection assets. As noted in section 4, while the need for dynamic reactive support can arise because of an externality, the Authority considers it impracticable to identify and charge the exacerbators. Moreover, dynamic reactive support provides a benefit in the form of enabling greater power to flow into a region. Thus beneficiaries-pay is an option, which the Authority favours. The beneficiaries of the greater power transfer enabled by dynamic reactive support could be determined by analysis of the situation with and without the dynamic voltage support, as it would affect power transfer.

5.5.25 Since the approach proposed for charging for dynamic reactive support is the same as that for interconnection and HVDC assets, to avoid repetition, the details of the proposal and an evaluation of it (including whether it is lawful, practicable, efficient and would recover costs) are set out in the discussion on the proposal for charging for interconnection and HVDC investments in section 5.6.

5.5.26 The Authority considers that a practicable and efficient alternative to recovering the costs of dynamic reactive support assets provided by Transpower would be to continue with the status quo approach of recovering the costs through the interconnection charge. However, as noted in chapter 4, this may result in an over-investment in dynamic reactive support because beneficiaries, and where efficient, exacerbators, do not face incentives to consider the costs of dynamic reactive support in their investment decisions. As a result, investment in dynamic reactive support is unlikely to be efficient.

Q22.	**What comments do you have about the Authority’s assessment and conclusion about charging options for dynamic reactive support?**

5.6 Proposal to recover all other HVDC and interconnection costs

Introduction

5.6.1 The HVDC and interconnection charges are the most contentious components of the TPM. The connection charge is generally not contentious as parties can readily verify the costs of supply and they accept they should pay for assets that directly benefit them. In contrast, the benefits of HVDC and interconnection services are indirect, the costs attributable to each user are hard to determine, and historically the methods used to recover those costs have not been closely linked to the benefits parties receive from these assets.

5.6.2 The Authority believes that parties generally accept charges when they can see the link between the charges they pay, the cost of service to them and the benefits they receive, whether the link is made through the operation of a market-like arrangement (as occurs for connection services) or by the adoption of a beneficiaries-pay basis for interconnection services. This is evidenced by the approaches adopted by Argentina[95] and by the New York Independent System Operator (NYISO) area, where economic models have been used to identify beneficiaries.

5.6.3 The Authority also notes support for this approach in case law from the United States of America, which established that the Federal Energy Regulatory Commission (FERC) cannot approve a transmission pricing scheme that requires parties to pay for facilities from which they derive no benefits, or face charges where the benefits to them are trivial in relation to the costs sought.[96] FERC adopted these principles in its order No. 1000, issued in July 2011, and recently confirmed them in May 2012 following consideration of submissions from interested parties.[97] This order requires transmission costs to be allocated "in a way that is roughly commensurate with benefits".

5.6.4 The proposal in this section seeks to charge for HVDC and interconnection services in proportion to the estimated private benefits that parties receive from those services. The proposal also allows those charges to automatically shift over time with changes in grid use and

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95 Between 1992 and 2002.

96 Illinois Commerce Commission v FERC, 576 F.3d 470, 476 (7th Cir., citations omitted), available at, http://www.ferc.gov/legal/court-cases/opinions/2009/PT1FG750-opinion.pdf.

97 FERC: *Transmission planning and cost allocation by transmission owning and public operating utilities*. Order 1000-A, May 17, 2012, available at: http://www.ferc.gov/whats-new/comm-meet/2012/051712/E-1.pdf

configuration, without the need to fundamentally review the methodology. The Authority believes the flexibility of this approach, and the greater clarity of the link to private benefits, should create a durable approach to the TPM and reduce the transaction costs associated with on-going lobbying and potential legal challenges for and against changing the TPM. It should also reduce the frequency with which the TPM needs to be reconsidered due to material changes in circumstances and provide efficiency benefits as a result.

5.6.5 Access to HVDC and interconnection services is currently rationed on a five-minute basis by the operation of the spot market. The SPD model is used to schedule and dispatch generation resources for five-minute periods based on the half-hourly offer prices submitted by generators.

5.6.6 As noted in section 5.3, the SPD model dispatches generation by taking into account *security constraints* in the grid and estimated *energy losses* from transmitting electricity from grid injection points to grid exit points. The presence of losses and constraints results in spot price differences across the grid, and produces *loss and constraint rentals* that the clearing manager (NZX Limited) transfers to Transpower. Transpower allocates rentals to its transmission customers in proportion to their share of charges for transmission assets. These rentals payments offset transmission costs, thereby in effect reducing transmission charges.

5.6.7 The spot market therefore already provides a market-based approach to paying for HVDC and interconnection services.

5.6.8 In principle, loss and constraint rentals (or FTR auction proceeds) could fully fund HVDC and interconnection services. In practice a large funding deficit occurs because grid investments typically exhibit large economies of scale. Even without economies of scale issues, a large deficit occurs if grid investments are made earlier than would be justified on economic grounds.

5.6.9 The Authority is proposing to use the SPD model to estimate the private benefits accruing to wholesale market participants, but it is quite likely the charges under this approach will be insufficient to cover the residual left by loss and constraint rentals[98]. Hence a second residual occurs, which the Authority is proposing to cover with a modified form of the current RCPD residual charging regime. The residual charge will be set to ensure full cost recovery for Transpower, but as the charge is analogous to a general

[98] This residual also arises in part because of economies of scale and uneconomic investments.

tax it can lead to inefficient bypass of the transmission grid and/or inefficient disconnection from the transmission grid.

5.6.10 Given the above interrelationships, the Authority's proposal for recovering the costs of HVDC and interconnection services is presented in four parts:

(a) Part 1: A proposal to codify the current arrangements where surplus loss and constraint rentals (and in the future, surplus FTR auction proceeds) received by Transpower from the clearing manager are to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals. For example, rentals originating on the assets being built under the North Auckland and Northland (NAaN) project would be applied to reducing the cost of the NAaN assets;

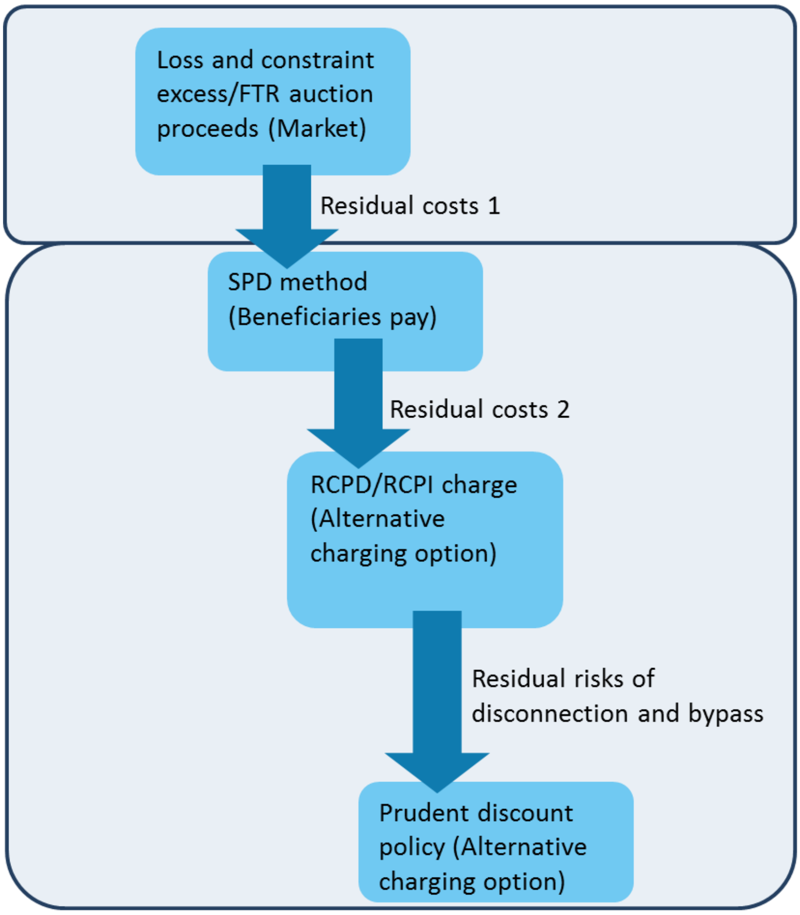
(b) Part 2: A proposal to use the SPD or vSPD model to (1) identify the beneficiaries of certain HVDC and interconnection investments and (2) estimate the extent of the private benefits they receive from those investments on a half-hourly basis. The beneficiaries identified by this method would be charged for the cost of each investment in proportion to their share of the benefits of each investment, but with the amount of this part of the charge not exceeding their private benefit in each case;

(c) Part 3: A proposal to modify the current postage stamp regime and introduce a residual charge, which would, in effect, involve a regional coincident peak demand (RCPD) charge to load and regional coincident peak injection (RCPI) charge to generation parties. The residual charge is to recover the residual balance of the costs of the HVDC and interconnection assets not recovered by other charges. The RCPD and RCPI charges should be set so that each raises half the residual balance. They should also be designed so that parties subject to the charge have efficient incentives to avoid peak use of the grid in the region in which they are located.; and

(d) Part 4: A proposal to modify the prudent discount policy (PDP) to better deal with the possibility of inefficient bypass of the grid and inefficient disconnection from the grid.

5.6.11 The Authority's proposals in relation to HVDC and interconnection, together with an explanation of how each element relates to the Authority's economic framework for the TPM is set out in Figure 7.

Figure 7: Overview of HVDC and interconnection proposal and relationship to economic framework



Proposal (part 1): codify current arrangements for the treatment of loss and constraint excess

5.6.12 As discussed in paragraphs section 5.3, the Authority proposes to codify the current arrangements in which the loss and constraint excess (and in the future, surplus financial transmission right auction proceeds) received by Transpower from the clearing manager is used to offset the components of Transpower's transmission charges that correspond to the origination of the loss and constrain excess. This would offset a portion of the costs of HVDC and interconnection assets but, as discussed, a large funding deficit occurs because grid investments typically exhibit large economies of scale and when grid investments are made earlier than is justified on economic grounds.

Proposal (part 2): use the SPD/vSPD models to set beneficiaries-pay charges for HVDC and interconnection services.

Description of the proposal

5.6.13 The Authority is proposing the SPD or vSPD model be used to (1) identify beneficiaries of certain HVDC and interconnection investments and (2) estimate the extent of the private benefits they receive from those investments on a half-hourly basis. The beneficiaries identified by this method would be charged for the cost of each investment in proportion to their share of the private benefits of each investment, but with their maximum charge not exceeding their private benefit in each case.

5.6.14 The Authority has developed and tested an approach for applying beneficiaries pay using vSPD, with benefits calculated for each trading period, and this is set out in Appendix E. To reduce repetition the remainder of this paper refers to SPD, with the understanding that the same points apply to application of the method using vSPD.

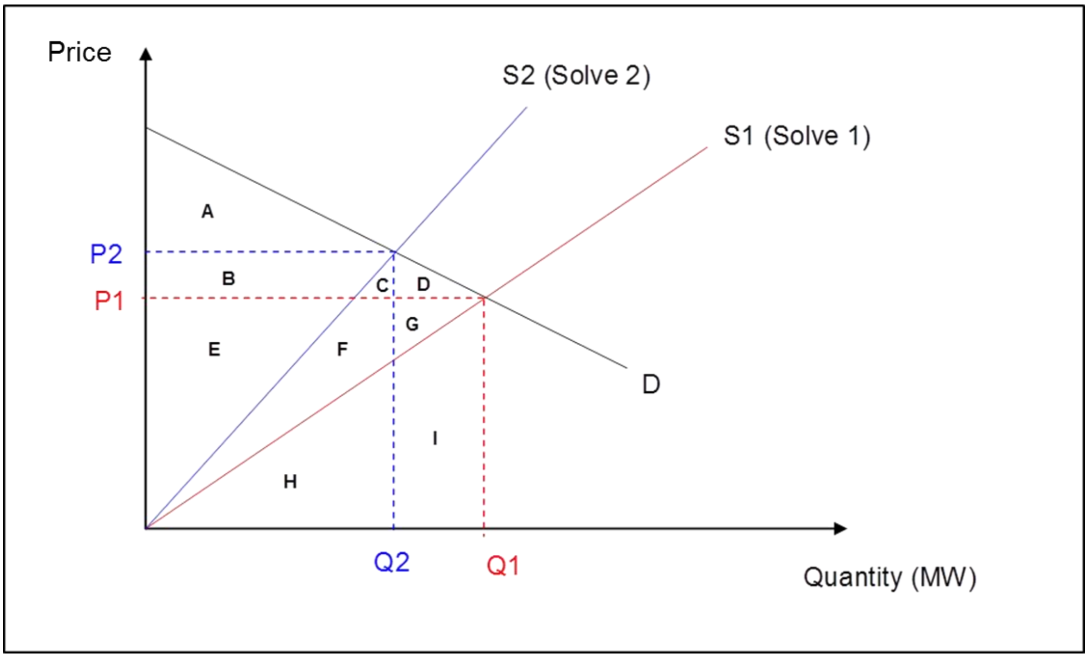
5.6.15 The private benefits of a grid investment accrue in two main forms:

(a) monetary benefits, which occur when installation of the grid asset simply alters wholesale market prices and quantities by reducing losses and constraints and allowing more power to be transferred; and

(b) non-monetary benefits, which occur when installation of the grid asset avoids supply interruptions to consumers. The private benefits in this case are avoided interruption costs.

5.6.16 Under the SPD proposal the monetary benefit to a party from having the asset available would be determined by comparing the price a party faced and the quantity of power injected or consumed at each node for solves of SPD or vSPD, with and without the asset. This is illustrated in Figure 8.

Figure 8: Illustration of calculated benefits from SPD solve



5.6.17 Figure 8 shows a demand curve, D, and two supply curves, S1 and S2. S1 is the supply curve with the grid asset installed (i.e. solve 1 of SPD) and S2 is the supply curve with the grid asset removed from the SPD model and security constraints reconfigured (i.e. solve 2). Figure 5 illustrates that the installation of the asset increases the quantity of electricity that can be supplied from Q2 to Q1 and reduces prices from P2 to P1.[99]

5.6.18 Measuring the monetary benefit to load from the asset involves comparing the area under the demand curve but above the price for solve 1 (i.e. areas A, B, C and D) with that for solve 2 (i.e. the area given by A alone). Measuring the monetary benefit to generation involves the opposite: comparing the area above the supply curve but below the price for solve 1 (i.e. areas E, F and G) with that for solve 2 (i.e. the area given by B and E). This is summarised in Table 6.

Table 6: Summary of calculation of benefits using SPD

	Solve 1	Solve 2	Change
Demand (offtake)	A + B + C + D	A	B + C + D

[99] Note that Q1 & P1 are the actual wholesale market outcomes and Q2 & P2 are simulated market outcomes that could have occurred if the grid asset had not been installed.

Supply (injection)	E + F + G	B + E	F + G - B

5.6.19 In other words, the calculation would be an estimate of the monetary value a party derived from the asset being available. This calculation could be performed for each half hour or five minute period. The calculation could either be made prior to dispatch or at the time of settlement of the wholesale market.

5.6.20 There are two potential approaches to applying this charge:

(a) applying the charge according to private benefit only; or

(b) applying the charge by subtracting any private disbenefits resulting from transmission (e.g. because wholesale prices reduce for generators at the receiving end of a transmission line when it is expanded) from private benefits, which would mean parties would be charged according to their private net benefit.

5.6.21 The Authority considers that it is appropriate to apply the charge only to private benefit as this is consistent with the approach in workably competitive markets, where buyers will not pay more than a service is worth to them and sellers will not succeed in charging more than buyers benefit. However, workably competitive markets do not usually involve compensating parties for any disbenefit they receive from a service. For example, Pukekohe potato growers are not compensated for the fall in prices as a result of potato growers from Oamaru entering the Auckland market. Moreover, charging parties up to their private benefit improves efficiency, as the parties will take the costs of the charge into account in making their decisions and will only purchase the service up to the level of their private benefit.

5.6.22 If there were multiple parties at a node the approach to estimating the monetary benefit to individual parties would be determined by the prices they face and their own level of load or generation under each solve of the SPD model.

5.6.23 The Authority is proposing to take a similar approach to the calculation of non-monetary benefits. The key difference in this case is that the SPD model will use an estimated price that a peaker generator would require to supply electricity to a node, as this would be the likely response in practice to prevent supply interruption if the transmission investment was not in place. This is the approach used in the approach developed by the Authority as set out in Appendix E.[100]

5.6.24 There are several alternatives to performing the benefit calculation each half hour or five minute period. First, the benefit could be calculated for a day or a month rather than for a trading period or 5-minute period. This would make the charge simpler to perform and would make the charge less variable but the magnitude of a daily or monthly charge may mean parties have greater incentives to act so as to avoid the charge.

5.6.25 Second, the calculation could be performed for a random sample of periods. The sample could be, for example, 1000 randomly selected periods from the previous year or more. This could be used to determine the charge that would apply for the current year or, potentially, future years.

5.6.26 Third, the benefit could be calculated on a rolling average basis. This could involve calculating the charge on the basis of the rolling average of private benefit as determined by SPD over a period sufficiently long to limit the variability of the charge and to avoid providing incentives for parties to inefficiently alter their behaviour to avoid the charge, e.g. 12 to 36 months.

5.6.27 The Authority proposes to adopt the half hourly approach rather than the random sample or rolling average approach. While this is likely to mean that transmission charges are more variable, determining the charge on such a granular basis more accurately reflects private benefit and limits the extent to which parties can take inefficient actions in order to avoid the charge. Further, as discussed below, variability in the charge will follow the wholesale market benefits to parties as a result of transmission assets.

Assets subject to the beneficiaries-pay charge

5.6.28 As foreshadowed in the framework consultation paper, the Authority considers that there are efficiency benefits from applying beneficiaries pay to assets already in place, as well as new investments. In particular, this ensures that existing and new assets are charged on a broadly comparable basis, thus providing pricing signals to parties considering investments that would be affected by transmission investment. It should also assist in making the charge more durable since assets providing similar services in different areas and implemented at different times would be charged on the same basis.

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[100] This was also the approach used by the Authority to determine the price that should apply at affected nodes for its UTS decision in relation to the events of 26 March 2011. See *Final decision on actions to correct the Undesirable Trading Situation of 26 March 2011*, 4 July 2011.

5.6.29 As discussed above, applying a beneficiaries-pay charge also provides information on the efficiency of investment decisions, thus helping inform future investment decisions, as efficiency requires that beneficiaries should only be charged up to their private benefit. Provided beneficiaries pay is efficiently applied, any costs not covered by beneficiaries may indicate the extent to which the investment is not efficient.

5.6.30 The Authority considers that these signalling benefits are likely to become more diffuse the more historic the transmission investment. Accordingly, the Authority proposes that the beneficiaries-pay charge would apply to assets added to Transpower's regulated asset base from 28 May 2004, the date when Part F of the Electricity Governance Rules 2003 came into force. The one exception to this is pole 2 of the HVDC link, which the Authority considers should also be subject to beneficiaries pay so that the charging basis for pole 2 is broadly consistent with the charging basis for pole 3.

5.6.31 The Authority proposes an investment cost threshold for application of the SPD method, below which costs would be recovered through a residual charge. It is proposed that this threshold would be $2m. The reason for this threshold is that this will capture transmission investments from which parties participating in the wholesale market benefit, including connection parties. This threshold will effectively mean that the Authority's approach would apply an automatic "but for" approach to determining connection charges.[101] Although this threshold is likely to mean the number of assets covered by the SPD method is large, which will increase cost and complexity, the Authority considers that the benefits of extensive application of the method exceed the costs.

5.6.32 The costs of interconnection assets not covered by this SPD-based beneficiaries-pay charge (i.e. assets built before 28 May 2004 (but not replacements or refurbishment of these assets) or assets built after 28 May 2004 but with a cost below $2m) would be recovered through the residual charge.

Parties subject to the beneficiaries-pays charge

5.6.33 The Authority proposes the beneficiaries-pay charge would apply to all parties that benefit from participation in the wholesale market, including those parties not directly connected to the grid. Participation in the

[101] That is, by applying the SPD method to assets to which connection customers may be the primary beneficiaries, the Authority's approach would identify assets beyond the physical connection boundary that would not be required "but for" the customer connecting to the grid.

wholesale market is possible only through a connection to the grid, whether direct or indirect, and it is appropriate that all parties that benefit from the grid contribute to its costs.

5.6.34 One implication of using SPD to apply beneficiaries pay is that there may be efficiency gains from levying the charge on retailers rather than distributors as the method uses inputs from the wholesale market. Retailers' demand for transmission services are likely to be more elastic than distributors' as the latter are able to fully pass through their transmission charge to retailers or end consumers under the Commerce Commission's price-quality regulatory regime. More elastic demand means retailers should have a greater incentive to scrutinise Transpower's investment proposals than distributors.

5.6.35 That said, distributors also benefit from transmission investment to the extent that they offer to supply or purchase from the wholesale market. Accordingly, to this extent distributors should also be subject to a charge calculated using the SPD method.

Discussion of the proposal

The SPD method should provide reasonable estimates of private benefits

5.6.36 The Authority's view is that it is not possible to design a perfect beneficiaries-pay charge with current technology, and it is not attempting to do so. The key issue for the Authority is whether the proposed beneficiaries-pay charge delivers greater economic benefits for consumers than any other lawful alternative available to it. All transmission pricing options involve approximations and compromises, and the SPD method to implementing beneficiaries pay is no different in that regard.

5.6.37 Nevertheless, the Authority believes the SPD method is likely to provide reasonable estimates of the private benefits accruing to industry participants. The Authority appreciates that SPD is not a full behavioural model, but it should provide reasonable lower-bound estimates of private benefits as participants will be free to alter the structure of their offers to the market when the beneficiaries-pay charge is introduced. [102] This should bring most of the behavioural aspects into SPD over time.

The SPD method brings transparency to investment decision-making

[102] Using a full behavioural model instead of SPD, as considered in chapter 6 of this paper, allows further adjustments in behaviour to be taken into account in assessing private benefits, but participants will only make these adjustments if doing so increases their net private benefits.

5.6.38 The Authority believes generators – and consumers once dispatchable demand is introduced – will try to structure their bids and offers to the spot market to minimise the estimation of their private benefits from specific grid assets.[103]

5.6.39 For example, South Island generators could reduce their beneficiaries-pay charge for pole 3 of the HVDC by making offers as if only pole 2 is available. Rather than being a problem with the SPD method, the Authority believes that outcome would reveal the need for pole 3, viz:

(a) if successful, the revised offering behaviour would reveal that pole 3 was not economically justified and does not deliver private benefits to South Island generators. The costs of pole 3 in this case should be recovered from consumers receiving private benefits from pole 3 (if any) or through the residual charge in a way that is analogous to a 'broad base low rate' tax on generators and loads for uneconomic grid investments; and

(b) alternatively, if South Island generators were unable to structure their offers to avoid the beneficiaries-pay charge then this suggests pole 3 delivers private benefits to them and that they should pay for (or a portion of) the costs of pole 3 up to an amount not exceeding their private benefits.

The SPD method provides a highly flexible (and durable) beneficiaries-pay charge

5.6.40 Another key advantage of using the SPD model is that the beneficiaries-pay charge would vary in accordance with variations in the benefits each party receives.

5.6.41 For example, if there is significant electricity demand growth in the North Island requiring increased South Island generation to meet it, then South Island generators would receive larger benefits from pole 3 on the HVDC link and under the SPD method they would automatically pay a larger share of the costs of pole 3. Similarly, any additional transmission investment required in the South Island to get the surplus power to the North Island would automatically be paid by South Island generators benefiting from those investments.

5.6.42 This flexibility should greatly reduce the need to fundamentally review the TPM in the future, bringing lower regulatory costs in the form of reduced lobbying activity and legal challenges, lower administrative costs

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[103] Grid connected consumers are likely to do the same once the dispatchable demand is implemented.

associated with on-going reviews of the TPM and lower regulatory uncertainty for investors (transmission customers).

Unlike for loss and constraint rentals, large economies of scale in grid investment do not necessarily result in funding deficits

5.6.43 Total revenue from loss and constraint excess and the beneficiaries-pays charge may not fully recover HVDC and interconnection costs. This funding deficit could occur if some grid investments are uneconomic, either due to the investment occurring too early or because industry changes render the investment permanently or temporarily uneconomic.

5.6.44 Funding deficits could also occur for grid investments exhibiting large economies of scale, although this is by no means certain. By definition, large economies of scale mean it is more efficient to undertake a large circuit augmentation once every 50 years, say, rather than 50 small augmentations at the rate of one a year (as circuit usage evolves).

5.6.45 Although in any given year it is far more costly to undertake the once-in-fifty year expansion than it is to do a small augmentation, the annualised cost of the former is lower than the latter. This minimises annual funding requirements.

5.6.46 Also, large grid expansions cause nodal price differences between the sending and receiving end of the grid augmentation to collapse. This results in either:

(a) large private benefits to consumers at the receiving end of the grid augmentation if the augmentation depresses spot market prices at the receiving end; or

(b) large private benefits to generators at the sending end of the grid investment if the augmentation lifts spot market prices at the sending end; or

(c) moderate private benefits to both parties and large total private benefits.

5.6.47 In contrast, loss and constraint excess largely evaporates when price differences across the grid collapse.

5.6.48 Aggregate private benefits are initially constrained by small increments in sending-end generation and receiving-end consumption. These quantity effects increase cumulatively over time for economically-justified investments, bringing rapid increases in private benefits until transmission losses and constraints begin to restore price differences across the augmented circuit.

The variability of the beneficiaries-pay charge should not cause cash-flow problems as they largely match volatility in monetary benefits from grid augmentations

5.6.49 The SPD method could result in more variable transmission charges than is currently the case but this variability will be largely predictable and in large part transmission charges would co-vary with the monetary benefits received by transmission customers. Charges under the SPD method could be levied over timeframes that minimise unpredictability and cash-flow impacts.

5.6.50 The SPD method avoids the need to apply a “but for” approach to connection charges in order to ensure beneficiaries pay. In doing so, the SPD method avoids the complications associated with trying to single out a subset of assets in the interconnected grid and charge for them in a manner inconsistent with that for similar unaffected assets.

Assessment against criteria

Lawfulness of using the SPD method to adopt beneficiaries-pay charges

5.6.51 The use of wholesale market models to identify beneficiaries and private benefit of transmission assets is lawful.

Practicability of using the SPD method to adopt beneficiaries-pay charges

5.6.52 The proposal uses an existing model (SPD or vSPD) to calculate charges and identify parties subject to the charge, and so it should be practicable to implement. The Authority’s work in this area using vSPD (see Appendix E) shows that it is practicable.

5.6.53 If a party other than Transpower was allocated the role of calculating the charge a method would be required to calculate security constraints consistent with the approach used by Transpower (who use the simultaneous feasibility test (SFT) model).

5.6.54 The main practical issue is the time and computational resources required to undertake separate SPD or vSPD solves for each asset for each half hour period. As such, the method is probably most practicably applied to a subset of transmission assets. If the computational resources were constrained, a charge based on a sample of a large number of trading periods over a long period (e.g. a year) could be used.

Assessment of costs and benefits of the SPD method

5.6.55 The benefits of the SPD method for implementing beneficiaries-pays charges are that:

(a) it promotes efficient transmission investment through increased transparency of the benefit parties obtain from transmission assets, and by placing stronger incentives on parties identified as beneficiaries to participate in the investment decision-making and approval process;

(b) it promotes efficient investment by generation and load, as allocating charges to beneficiaries means they will face the transmission cost implications of their investment decisions;

(c) it promotes allocative efficiency through more efficient prices by reducing deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge would be paid for by beneficiaries. The reduction in deadweight loss would depend on the extent to which the charge reflects aggregate benefit;

(d) it promotes productive efficiency as calculation of the charge can be made contestable; and

(e) it promotes durability because a robust and justifiable approach is used to determine beneficiaries, who are then charged for the HVDC and interconnection services they receive. This provides flexibility to deal with changes in asset use and configuration and will reduce on-going lobbying for a change to the TPM. This in turn will result in savings in expert legal and technical/economic resources and reduce regulatory uncertainty about the TPM.

5.6.56 The likely costs of the proposal are:

(a) the implementation costs for both Transpower and participants, including set-up costs involved in implementing the option, including computer equipment, any licence costs, development and testing;

(b) there operational costs, including the on-going costs of applying the option to estimate the benefits from transmission assets;

(c) the costs to participants of using more complex models to verify their transmission charges; and

(d) the incentives on parties to alter their use of the grid in order to seek to minimise their exposure to the charge in ways that would be inefficient. This would need to be addressed, to the extent it could be, through the design of the charge or through other mechanisms, such as the prudent discount policy.

5.6.57 The potential outcomes identified above result from a combination of allocative and dynamic efficiency gains. The primary driver of these gains is improved information and incentives, affecting a myriad of decisions. Improved information and incentives will likely lead to new and better processes and investment decisions which in turn will raise the level and growth rate of the productivity of the sector in the long run; that is, an improvement in dynamic efficiency. By contrast, the welfare gains that can be achieved through allocative efficiency gains are usually “exceedingly small.” As allocative efficiency gains would be achieved through transmission charges better reflecting demand, and the improved incentives and information that would produce this benefit are captured within the estimate of dynamic efficiency, an allocative efficiency estimate is not counted in addition to the dynamic efficiency estimate.

5.6.58 Overall, the proposal provides a means of identifying beneficiaries and private benefit of transmission assets, based on a party’s activity in the wholesale market.

5.6.59 The main disadvantage of the proposal is that the price used to determine private benefits when a transmission asset avoids non-supply of electricity would be based on data external to the spot market (i.e. the cost of a peaker generator). The estimate of non-monetary benefits is dependent on the reference price chosen.

Potential to recover HVDC and interconnection costs

5.6.60 Although this is by no means certain, the SPD method may under-recover costs in the years immediately following a large transmission investment. As for deficits in funding associated with loss and constraint rentals, the Authority proposes to recover any such residual with a residual charge as described below.

Q23. What is your view of the Authority’s assessment and conclusions about using the SPD or vSPD model to establish a beneficiaries-pay charge for recovering some or all HVDC and interconnection costs?

Conclusion on the proposal to use a beneficiaries-pay charge to help recover HVDC and interconnection costs

5.6.61 The Authority is proposing to apply beneficiaries pay to all remaining assets to which the connection and NRS charges would not apply; to the extent this would deliver net benefits. In practice this includes the HVDC and current interconnection assets. The Authority notes that beneficiaries pay is supported as an appropriate basis for applying transmission charges by the US courts[104], international experts[105], and by emerging international practice[106].

Conclusion on the SPD method for implementing a beneficiaries-pay charge

5.6.62 Chapter 6 of this paper outlines other methods the Authority has considered for implementing a beneficiaries-pays charge to help recover the costs of HVDC and interconnection services.

5.6.63 Of the beneficiaries-pay options, the Authority considers that the SPD method is likely to represent the most consistent and efficient means of applying beneficiaries pay. This is because it uses outcomes from the wholesale market as the basis for determining the private benefits from a grid investment. This means that the charge applying to a party should reflect the benefit they obtain from the investment over time.

5.6.64 The approach proposed by Professor Hogan of applying beneficiaries pay involves determining the charge that would apply to parties prior to an investment, with the charge fixed over time.[107] Although this approach has some merits, the Authority considers that a key difficulty with such a charge is it is calculated on the basis of anticipated benefits rather than actual benefits. This creates a risk for efficient investment as parties will be reluctant to invest if they may continue to be subject to a charge even though they no longer benefit from the investment. This could adversely affect competition, and does not take into account new entry.

5.6.65 Although allocating FTRs to parties subject to the charge may mitigate the adverse impacts of such a fixed charge to some degree, this would not address situations such as a major beneficiary exiting the market. Although the charge could be recalculated if such an event occurred, this would inevitably be subject to considerable dispute, threatening the

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[104] Illinois Commerce Commission v FERC, 576 F.3d 470, 476 (7th Cir., citations omitted), available at, http://www.ferc.gov/legal/court-cases/opinions/2009/PT1FG750-opinion.pdf.

[105] See: Hogan, WW: *Electricity market reform: Market design and the green agenda.* Presentation at New Zealand Electricity Authority, 20 July 2012; Read, EG, *Allocating transmission costs to beneficiaries: Lessons from New Zealand Experience.* Presentation to ACCC Regulatory Conference, July 27 2012.

[106] : See: Littlechild, SC and Skerk, CJ: "Regulation of transmission expansion in Argentina Part I: State ownership, reform and the fourth line", CMI EP 61, 2004; Hogan, WW: *Electricity market reform: Market design and the green agenda.* Presentation at New Zealand Electricity Authority, 20 July 2012, page 37.

[107] See: Hogan, WW: *Electricity market reform: Market design and the green agenda.* Presentation at New Zealand Electricity Authority, 20 July 2012; and Hogan, WW: *Transmission benefits and cost allocation*. Mossavar-Rahmani Center for Business and Government, John F. Kennedy School of Government, Harvard University, May 31, 2011.

durability of the approach. By contrast, the SPD method does not suffer from these problems.

Q24. **Do you agree with the Authority's conclusion that the most efficient beneficiaries-pay charging option for applying to HVDC and interconnection costs is likely to be the SPD method? Please provide an explanation for your answer.**

Q25. **Do you consider that there are beneficiaries-pay options that the Authority has not identified that are practicable, would deliver greater net benefits and would recover HVDC and interconnection costs? Explain your proposal.**

Proposal (part 3): use postage stamp charges to ensure Transpower's full economic costs are recovered

Introduction

5.6.66 As discussed above, the beneficiaries-pay charge may not recover the full costs of a grid investment to which it is applied, in particular for those investments that are made for the purposes of meeting the deterministic limb of the grid reliability standards and justified on a "least cost" basis rather than a "greatest benefit" basis".[108] The Authority is proposing to apply these charges to post-28 May 2004 transmission assets and to pole 2 of the HVDC link. At a minimum, a residual charge is required above $2 million to cover the costs of pre-28 May 2004 transmission assets apart from pole 2 of the HVDC link.

5.6.67 The Authority considers that an efficient residual charge is one that:

(a) minimises distortions in use of the transmission grid resulting from the imposition of the residual charge; and

(b) ensures the costs of providing transmission investments approved under the relevant regulatory regime are fully recovered (as required by law) and so future investment is not stifled by the concerns of investors in the grid that they will not recover the costs of approved investment.

5.6.68 Before determining whether other options should be considered for the residual charge, it is useful to consider whether the current interconnection charge, calculated on the basis of RCPD, meets these principles.

[108] The North Island Grid Upgrade proposal, Otahuhu Substation Diversity proposal and the North Auckland and Northland proposal are all such investments.

5.6.69 Chapter 4 identified that the current RCPD allocation of interconnection charges may be inefficient. In particular:

(a) it incentivises what appears to be inefficient demand-side response in the LNI;

(b) it creates a deadweight loss in the tens of millions of dollars (NPV) because it applies to non-beneficiaries and, for some customers, the charge will exceed their private benefit;

(c) it may promote inefficient transmission and generation investment as generators that benefit from investment in interconnection assets do not face the associated costs. This means generators have incentives to lobby for transmission investment but lack incentives to seek to minimise costs. Further, since other parties pay interconnection transmission costs, to the extent that generators benefit from this investment but do not contribute to the costs, generators' activities are cross-subsidised; and

(d) distributors may lack sufficient incentives to respond to RCPD price signals because of their ability to pass on transmission charges under the Commerce Commission's input methodologies. The evidence supports this to some extent. In particular, some distributors in the UNI do not appear to respond to price signals even though the number of periods used to calculate RCPD for the UNI is intentionally small (12) so that parties facing the charge have strong incentives to limit peak demand. By contrast, distributors in the USI do appear to respond to the peaks. If parties lack incentives to respond to the charge, this limits the extent to which RCPD can promote efficient investment in, and operation of, generation and demand-side resources.

5.6.70 In addition to these issues, another factor that needs to be considered in the design of a residual charge is that if more efficient charging options are applied, parties facing these charges will receive price signals about the cost implications of their activity for investment in the grid. Because these price signals will apply only to beneficiaries (for market, market-like, or beneficiaries pay charges) or exacerbators (where exacerbators-pay charges are applied) the price signals will be more efficient than under the RCPD methodology. This is because the RCPD approach also charges non-beneficiaries and non-exacerbators.

5.6.71 It would therefore be appropriate for the residual charge to incorporate a price signal only where more efficient charging methods would not be applied to new investments. However, the previous sections have identified that more efficient options could be applied across the grid, which would allow more efficient price signals for all new investments. Accordingly, there do not appear to be strong reasons for the residual charge to incorporate price signals for more efficient investment.

Description of the proposed residual charge

5.6.72 The Authority proposes that the above issues be addressed by modifying the current RCPD charge. In particular, the Authority proposes that the residual charge:

(a) would be applied to generation as well as load;

(b) should in principle be applied to electricity retailers as well as direct connect customers; and

(c) should, to the extent possible, be incentive neutral if other charges are introduced that provide incentives for more efficient investment.

Parties that should pay a residual charge

5.6.73 Applying a residual charge to generation as well as load broadens the base across which the charge is recovered. This minimises the extent to which the charge affects non-beneficiaries and minimises overcharging of beneficiaries, reducing the extent to which the charge would distort use of the transmission grid. Further, by applying the charge to generators as well as consumers, generators would have an incentive to consider the cost implications of any transmission investment they advocate for.

5.6.74 It is likely that generators would seek to pass the charge on to consumers by raising their wholesale offers. To the extent that some generators face higher transmission costs than others (which is likely under the proposed approach) there will be a constraint on how much these generators can pass on in their charges. In other words, the situation is likely to be analogous to the ability of a potato farmer from Oamaru seeking to pass on the costs of transport of their potatoes to Auckland when they face competition from potatoes produced in Pukekohe. If generators face the charge they would have greater incentives to scrutinise the costs of transmission investment recovered through the charge, which would help promote more efficient transmission investment.

5.6.75 Where generators are unable to pass on the costs of the residual charge they may have incentives to embed in distribution grids to avoid the charge. However, access to the prudent discount policy should avoid the extent to which this is a significant problem.

5.6.76 Similar arguments apply in relation to retailers paying residual charges. Since all retailers operating at a node would face the same charge they would face the same costs and therefore have an ability to pass the charge onto consumers. Again though, because they must pay the charge, they have greater incentives to scrutinise transmission investments covered by the charge.

5.6.77 Applying the charge to generators and retailers (and to large consumers purchasing directly from the wholesale market) rather than distributors would have some disadvantages, however:

(a) it would narrow the breadth of coverage as there are fewer generators and retailers (which in most cases are vertically integrated businesses) than distributors. However, since distributors have the ability to pass on the charge – which, in practice, they do to either retailers or consumers – the practical incidence of the charge would not be expected to change significantly;

(b) it would mean not all beneficiaries would face the residual charge. Distributors are also beneficiaries of the transmission system by virtue of the access it gives their customers to low cost generation and increased reliability, which influences demand for distribution services, and by enabling them to access the wholesale market to offer interruptible load; and

(c) if distributors no longer faced the charge, the costs of transmission recovered through the charge would no longer be transparent to them. Accordingly, they would lack any incentive to ensure their activities took into account the implications for transmission costs.

5.6.78 The Authority proposes that the residual charge would apply to distributors but distributors would have the ability to opt out of the charge except to the extent they benefit from offering interruptible load, and subject to first consulting with retailers operating on their network. This would mean all retailers operating on the networks of distributors that elected to opt out would become subject to the charge. Distributors would continue to be subject to connection charges, as appropriate, and would also be subject to the grid reactive support charge.

Q26. Do you agree with the proposal to apply the residual charge to:

a. Generators;

b. direct-connect major users;

c. distributors, except where they opt out from the charge; and

d. retailers, where distributors elect to opt out from the charge?

Q27.	**Do you agree with the proposal that distributors may opt out from the residual charge:**
a.	**to the extent that they do not benefit from offering interruptible load on the wholesale electricity market; and**
b.	**provided they consult with retailers that may be affected before they opt out?**

RCPD/RCPI designed to encourage efficient avoidance of peak regional use of the grid

5.6.79 The NRS and beneficiaries-pay charges provide price signals that promote efficient investment to the extent they encourage more scrutiny of transmission proposals and investment decisions. However, the beneficiaries-pay charge, in particular, does not provide prices reflective of incremental transmission investment costs. The Authority therefore proposes that the peak charge that would incorporate such a price signal be designed so that it encourages efficient avoidance of peak use of the grid.

5.6.80 The Authority proposes that the residual charge would in effect consist of two charges - an RCPD charge and an RCPI charge, with half of the residual revenue recovered from load and half from generators. The reason for this balance is that, excluding the effects of losses and constraints, the amount of electricity generated is roughly equal to the amount of electricity consumed, and the Authority considers that this represents a reasonable basis for apportioning residual costs between generation and load.

5.6.81 The Authority proposes that Transpower would determine:

(a) the optimal regions for applying the charge; and

(b) the number of regional coincident peaks for load and generation in each region to determine the charge that would apply. The number of peaks should reflect what is necessary to encourage efficient avoidance of peak use of transmission in each region.

5.6.82 Further, the Authority proposes that Transpower would review the number of peaks every three years to ensure that the charge was efficient and this would be subject to review by the Authority.

5.6.83 The Authority’s proposal has the advantage of requiring minimal alteration to the charging approach for load and it is also a method that is familiar to load parties. The new RCPI charge on generation would require development, however.

5.6.84 The main potential disadvantage with this proposal is that it may provide a disincentive to peaking generation operating at times of peak demand. This effect would be minimised if the number of periods for calculation of the charge reflected this risk. In addition, because the residual charge will in effect consist of both an RCPD charge and an RCPI charge this would alleviate this issue. Further, if generators are able to pass on the charge to a significant extent in their wholesale offers, this effect should be minimal.

5.6.85 The other main disadvantage of the proposal is that it would be unlikely to prevent inefficient activity to avoid the charge. Parties would continue to be able to estimate the peak and adjust their use of the grid to limit their share of the peak, which may be inefficient to some degree.

Assessment against criteria

Lawfulness of RCPD-RCPI charge

5.6.86 The proposal is lawful under the Code.

Practicability of RCPD-RCPI charge

5.6.87 The main implementation challenge is likely to be obtaining sufficiently accurate data on load and/or generation quantities. For instance, if the charge was levied on all generation, it might be difficult to obtain output data for the smaller embedded generators.

Economic assessment of RCPD-RCPI charge

5.6.88 The economic benefits of an RCPD-RCPI charge that seeks to encourage efficient avoidance of peak regional use of the grid are:

(a) it promotes more efficient generation and load investment by helping to ensure that transmission investment only occurs when the benefits exceed the costs of alternatives to avoid transmission peaks; and

(b) it promotes more efficient use of the grid by encouraging efficient avoidance of peak regional use of the grid.

5.6.89 The economic costs of an RCPD-RCPI charge that seeks to encourage efficient avoidance of peak regional use of the grid are:

(a) the implementation costs to Transpower for developing RCPD and RCPI and determining number of peaks to calculate the charge;

(b) the operational costs to Transpower of applying the charge (not significant);

(c) the implementation costs of parties subject to the RCPD-RCPI charge;

(d) the costs to parties of complying with charge; and

(e) the disincentive for investment in peaking generation but this would be minimised if the number of periods used to calculate the charge reflected this risk, and may not be significant anyway if peaking generators are able to pass on the costs of the charge in their wholesale offers.

5.6.90 The benefits of an RCPD-RCPI charge that seeks to encourage efficient avoidance of peak regional use of the grid, in terms of more efficient investment and more efficient use of the grid, are likely to exceed the costs as the major cost of disincentivising peaking generation should be minimal with good design.

5.6.91 This charge is likely to complement a beneficiaries-pay charge that calculates charges every trading period using the SPD model. This is because that approach would provide price signals for efficient investment while this RCPD-RCPI charge would provide efficient incentives to avoid regional transmission peaks. In effect, the combination of the two charging methods would be a two-part charge.

Potential to recover residual transmission costs

5.6.92 This option could be applied across the grid to all costs.

Q28. Do you consider that the proposed RCPD/RCPI charge, designed to encourage efficient avoidance of peak regional use of the grid, with half of the residual revenue recovered from load and half from generators, would best complement a beneficiaries-pay charge that calculates charges every trading period using the SPD model? Explain your response.

Q29. Do you agree that the RCPD/RCPI charge would best meet the principles for an alternative charging option of:

a. minimising the distortion in use of the transmission grid resulting from the imposition of charges; and

b. ensuring the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered so future investment is not stifled by concerns of investors that they will not receive a return on their approved investment?

Explain your response.

Q30. Do you agree that the Authority's preferred option for the residual charge should be an RCPD/RCPI charge designed to encourage

efficient avoidance of peak regional use of the grid? Explain your response.

Proposal (part 4): refine the current prudent discount policy

5.6.93 All transmission charging methods require compromises to make them practicable and to minimise transaction costs, and no charging option is truly incentive-free.

5.6.94 As a result, the charging regimes proposed in this chapter, as with most transmission charging regimes, could result in a party inefficiently bypassing the grid (by investing in a transmission alternative) or inefficiently disconnecting from the grid.

5.6.95 In particular, consumers could seek to do this by investing in generation to reduce their net offtake from the grid, or investing in generation in order to disconnect entirely from the grid and grid-connected distribution networks.

5.6.96 The primary concern here is the residual charge, as the beneficiaries-pay charge applies a levy to each party of a portion of their private benefits, with the maximum charge set at the estimated value of their private benefit. Consumers receive net private benefits provided the charge does not equal or exceed their private benefit. It would not be economically rational for a consumer to reduce their private benefits by $100 so as to reduce their beneficiaries-pay charge by $90, for example.

5.6.97 However, the current prudent discount policy does not apply when the alternative to connecting to Transpower's grid is investing in generation. This means that such investment (where the private benefits to the parties making such an investment, including avoiding the residual charge, exceed the costs), may go ahead even if, from an economy-wide point of view, it would be inefficient. The Authority considers that the prudent discount policy should address this issue.

5.6.98 Generators seeking to reduce their transmission charges have the option of disconnecting from the grid and embedding in distribution networks. Both the beneficiaries-pay charge and residual charge could encourage this behaviour as a generator could obtain the same benefits from a distribution network as they obtain from the grid but for a lower charge. To some extent this incentive is already addressed by the prudent discount policy. However, any prudent discount agreement is limited to 15 years, which may be an insufficient period to avoid generator incentives to inefficiently disconnect from the grid in order to avoid the charge. The

Authority therefore proposes to amend the charge so that it may apply for the expected life of the asset to which the prudent discount applies.

5.6.99 In summary, the Authority proposes that the prudent discount policy be amended so that it:

(a) applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges; and

(b) may apply for the expected life of the asset to which the prudent discount applies.

Assessment against criteria

Lawfulness of amending the prudent discount policy

5.6.100 The proposal is lawful under the Code.

Practicability of amending the prudent discount policy

5.6.101 The main implementation challenge would be how to extend the prudent discount policy so that it applied to load investing in generation. However, the issues are not expected to be any more complex than the issues already involved in applying the prudent discount policy to generation or load seeking to bypass Transpower's assets by connecting to a distributor's network.

Assessment of amending the prudent discount policy

5.6.102 The economic benefits of amending the prudent discount policy to avoid inefficient disconnection are:

(a) it promotes more efficient generation and load investment by avoiding providing incentives for parties to invest so as to avoid transmission charges; and

(b) it promotes more efficient use of the grid by ensuring that parties use the grid where it is efficient to do so.

5.6.103 The economic costs of amending the prudent discount policy to avoid inefficient disconnection are:

(a) the implementation costs to Transpower for developing amendments to the prudent discount policy;

(b) the operational costs to Transpower of applying the prudent discount policy;

(c) the costs to parties that make applications for a prudent discount; and

(d) the reduction in allocative efficiency because of increased deadweight loss because the residual charge will need to be higher than it otherwise would for parties not subject to prudent discounts.

5.6.104 The benefits of extending the prudent discount in terms of promoting more efficient investment and reduction in charge avoidance behaviour are likely to exceed the costs, which mainly relate to implementation and reduction in allocative efficiency because of the increase in the residual charge as a result of prudent discounts.

Potential to recover residual transmission costs

5.6.105 This option would result in a need to increase the residual charge to the extent that the prudent discount applied to ensure that Transpower was able to recover its costs.

Q31. What are your views about amending the existing prudent discount policy to provide that it

a. applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges; and

b. may apply for the expected life of the asset to which the prudent discount applies?

Explain your response.

5.7 Cost-benefit analysis of overall proposal

Recap of the Authority's proposal

5.7.1 A recap of the Authority's proposal is set out below, and the other options the Authority considered are presented in chapter 6. The proposed guidelines for Transpower to follow in developing a TPM are provided in chapter 7.

5.7.2 The Authority is proposing the following approach for recovering transmission costs.

The parties that derive a private benefit from transmission services should pay transmission charges that are commensurate to their private benefit

5.7.3 The Code should be amended to enable Transpower to recover the costs of providing transmission services from the parties that benefit from transmission services: generators, direct-connect major users, retailers, and distributors.

Recovery of connection costs

5.7.4 The costs of connection to the grid should be recovered from the individual parties connecting to the grid: generators, direct-connect major users, and distributors.

5.7.5 Connection assets are those assets defined in clause 6(1) of Schedule 12.4 of the Code (the TPM).

5.7.6 The connection charge description in the TPM should be amended to include a purpose statement that establishes the principle of full economic cost recovery for all new investments, including where existing assets are replaced.

5.7.7 The connection provisions under the current TPM should be amended to provide:

(a) that current connection assets remain defined as connection assets until they are eventually replaced (at which point a new investment agreement would be required) or decommissioned;

(b) for referral to the Authority to consider and rule on special cases when the provision set out under 5.7.7(a) results in unintended outcomes;

(c) that replacement assets are valued for charging purposes at the actual replacement project cost; and

(d) for a connection customer to refer to the Authority to determine any connection charges the connection customer considers had been set at an unreasonable level as a result of asset replacement.

Recovery of network reactive support costs

5.7.8 The costs of static reactive support assets should be recovered from off-take transmission customers through a kvar charge. The rate of the kvar charge should be based on the long-run marginal cost of grid-connected static reactive compensation assets. Each off-take customer should be charged according to their average aggregate kvar draw from the grid.

5.7.9 The Connection Code should be amended to require a minimum power factor of 0.95 lagging in all regions.

5.7.10 The costs of dynamic reactive support assets should be recovered using the same charging method as for HVDC and interconnection services.

Recovery of HVDC and interconnection costs, excluding static NRS assets

5.7.11 Part 1: The costs of HVDC and interconnection services other than the costs relating to static NRS assets should first be funded from any loss and constraint rentals and FTR auction proceeds relating to HVDC or interconnection assets received by the grid owner. These sources of revenue should be applied to the costs of HVDC and interconnection assets to which the rentals or auction proceeds originate;

5.7.12 Part 2: If there are residual costs arising from the funding in Part 1 then the residual cost of the following investments should be charged to the parties that derive a private benefit from these investments:

(a) pole 2 of the HVDC; and

(b) HVDC and interconnection investments added to Transpower's regulated asset base since 28 May 2004 with a cost of more than $2 million (at the time the assets are added).

5.7.13 The “beneficiaries” of these investments should be determined using the SPD method set out in Appendix E. Parties should be charged according to their assessed private benefit, based on their share of injection or off-take in each trading period at nodes identified as benefiting from the investment. The charge should be applied to any party purchasing from or offering to the wholesale market.

5.7.14 Transpower or another party approved by the Authority would undertake the beneficiary assessment and calculate the charge each month, for each trading period in the month.

5.7.15 Part 3: The costs of transmission services that are not recovered through the charges above should be recovered through a uniform RCPD/RCPI charge that would apply to generators, direct-connect major users, distributors (unless a distributor opts out of the charge under the proposed opt-out mechanism), and retailers (where distributors opt out of the charge).

5.7.16 Transpower should calculate the uniform RCPD and RCPI charges on the basis that each charge recovers 50% of the costs of the residual and so that the charges encourage efficient avoidance of peak use of transmission in each region.

5.7.17 Part 4: The current prudent discount policy should be refined to provide Transpower with the obligation to minimise inefficient bypass of the grid and inefficient disconnection from the grid, regardless of whether the alternative project is investment in generation or distribution.

Summary of the CBA results

5.7.18 Sections 5.3 to 5.5 provide a qualitative analysis of the costs and benefits of the proposal, and chapter 6 provides the same for other options the Authority has considered. This subsection provides a quantitative analysis of the costs and benefits of the Authority's proposal against a counterfactual of the status quo.

5.7.19 The Authority has also undertaken a cost-benefit analysis of the option favoured by the majority of the TPAG against the counterfactual of the status quo to assess whether the Authority's proposal delivers larger net economic benefits. The TPAG minority view supported the status quo in regard to HVDC and interconnection costs.

5.7.20 The cost-benefit analysis is set out in Appendix F. The cost-benefit analysis estimates the net present value of the economic costs and benefits from the Authority's proposal and the TPAG majority view over a 30-year period using a discount rate of 6.01 per cent real.

5.7.21 The overall results of the analysis, for the central case, are provided in Table 7 below.

Table 7: Summary of economic costs and benefits

Present value of costs and benefits	Authority proposal ($ million)	TPAG majority view ($ million)	Difference between options ($ million)
Economic costs	$50.1	$0.9	$49.2
Economic benefits	$223.3	$50.2	$173.1
Net economic benefit	$173.2	$49.3	$123.9

5.7.22 A breakdown of the costs and benefits by transmission service is set out in Table 8.

Table 8: Breakdown of aggregate net economic benefits by transmission service (central case)

Present value of economic benefits	Authority proposal ($ million)	TPAG majority view ($ million)	Difference between options ($ million)
Interconnection - HVDC	$158.2	$36.3	$121.9
Reactive support	$13.0	$13.0	$0.0
Connection	$2.0	$0	$2.0
Total	**$173.2**	**$49.3**	**$123.9**

5.7.23 Sensitivity analysis of the costs and benefits for the Authority's proposal and the TPAG majority view is presented in Table 9. This provides sensitivity analysis for two cases: optimistic (low costs and high benefits) and pessimistic (high costs and low benefits).

Table 9: Optimistic and pessimistic sensitivity analysis

Sensitivity of economic costs and benefits (in present value terms)	Authority proposal (Optimistic) ($ million)	Authority proposal (Pessimistic) ($ million)	TPAG majority view (Optimistic) ($ million)	TPAG majority view (Pessimistic) ($ million)
Economic costs	$32.0	$81.0	$0.4	$1.9
Economic benefits	$300.7	$166.1	$68.4	$34.6
Net economic benefits	$268.7	$85.0	$67.9	$32.7

5.7.24 The sensitivity analysis suggests the Authority's proposal is robust to alternative assumptions.

5.7.25 Although the Authority's proposal involves substantially higher costs than the TPAG majority view in all scenarios, this reflects the choice of counterfactual. A different counterfactual, such as a theoretically optimal transmission charge, would reduce the economic benefits of the Authority's proposal and increase the economic costs of the TPAG majority view by the corresponding amount, leaving the difference between them unchanged.

5.7.26 Accordingly, the Authority considers that its proposal is likely to deliver significant net economic benefits relative to the status quo and that the net economic benefits would be greater than the alternative favoured by the majority of the TPAG.

Q32. Do you agree with the assessment of the economic costs and benefits of the Authority's TPM proposal versus the counterfactual? Explain your answer.

Q33. Do you agree with the assessment of the costs and benefits of the TPAG majority view against the counterfactual? Explain your answer.

5.8 Assessment against the Authority's objective

5.8.1 The Authority's objectives in relation to the TPM are to promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers. In particular, amendments to the TPM should facilitate:

(a) efficient investment in the electricity industry through providing incentives so that the right investments occur at the right time and are in the right place. These investments can be in the transmission grid, generation (including distributed generation), distribution networks or demand-side infrastructure to manage electricity consumption; and

(b) efficient operation of the transmission grid, generation (including distributed generation), distribution grids and demand-side management. This means providing incentives so that the day to day operation of transmission, generation, distribution and demand-side management involves an efficient trade-off between reliability and cost.

5.8.2 Efficient participation in the regulation of the TPM is a key consideration, but these effects operate through the above efficiency criteria. The TPM has been subject to considerable debate, lobbying and court action over many years, drawing valuable time and effort away from other productive activities. Establishing a robust and durable approach to the TPM will improve efficient investment in the electricity industry by reducing regulatory risk regarding the on-going prospect of changes to the TPM and improve efficient operation of the electricity industry by increasing productivity.

5.8.3 The Authority's proposal promotes the Authority's objective in relation to the TPM for the reasons presented in paragraphs 5.8.4 to 5.8.5 below.

Facilitation of efficient investment in the electricity industry

5.8.4 The Authority's proposal facilitates efficient investment in the electricity industry through:

(a) codifying the current treatment of loss and constraint rentals received by the grid owner and the future treatment of FTR auction proceeds. Codifying current and future practice should ensure regulatory uncertainty does not arise in regard to the way in which these sources of revenue are allocated to offset the transmission services. This should assist with investor certainty;

(b) <u>continuing the current arrangements for charging connection assets but with minor modifications to close loopholes.</u> Continuing the current regime means that parties connecting to the grid will continue to face the costs associated with connection, which provides them with incentives to take into account these costs in their investment decisions. This will promote efficient investment in connection assets and efficient investment in activities that require connection assets. The minor modifications to close loopholes will remove incentives for parties to undertake investments solely to reclassify connection assets as interconnection assets;

(c) <u>introducing the NRS charge together with a requirement for a power factor of 0.95 lagging in all regions.</u> The NRS charge means that parties drawing reactive power from the grid face the costs for the grid resulting from their activity. This provides them with incentives to draw reactive power only where it is efficient to do so, or otherwise invest in equipment to manage their reactive power use. This will promote more efficient in static reactive power equipment in the grid and by consumers of reactive power;

(d) <u>introducing a beneficiaries-pay charge using SPD or vSPD as described in section 5.5</u>. This charge will mean beneficiaries will pay for transmission investments and associated services from which they benefit, up to their private benefit. Beneficiaries have incentives to take these costs into account in their own investment activity and to seek the most efficient transmission investment option. Further, because parties would only be charged up to their private benefit, to the extent that any costs have to be recovered from non-beneficiaries through the residual charge, the beneficiaries-pay charge will make the efficiency of transmission investments transparent over time. This will provide incentives on Transpower and advocates for the investment to ensure investments are efficient;

(e) altering the current RCPD charge on load and introducing a similar RCPI charge on generators that seeks to encourage efficient avoidance of peak regional use of the grid. The RCPD/RCPI charge will promote efficient investment by broadening the base across which a uniform charge is levied, which should reduce the extent to which charges exceed a party's private benefit and reduce distortions to behaviour from the charge. Further, any reduction in the extent to which the charge exceeds a party's private benefit should reduce the extent to which transmission charges result in barriers to entry, which should improve competition and, therefore, investment; and

(f) refining the current prudent discount policy. This component of the TPM facilitates efficient investment in the electricity industry by giving Transpower the ability to negotiate charges when inefficient grid bypass or inefficient grid disconnection is likely to occur, when the alternative project is generation-based.

Facilitation of efficient operation of the electricity industry

5.8.5 The Authority's proposal facilitates efficient operation of the electricity industry through:

(a) introducing a NRS charge. This charge will ensure that parties drawing reactive power will operate their equipment so that they only draw reactive power from the grid to the extent that the benefits exceed the costs, including the costs of the NRS charge;

(b) introducing a beneficiaries-pay charge using SPD or vSPD as described in section 5.5. Applying the charge to all parties that benefit from the transmission grid reduces (relative to the status quo) the incentive for parties to reduce their use of the grid or disconnect from the grid in order to avoid the charge. In addition, by applying the charge in all trading periods, any disincentive to use the grid in any particular trading period as a result of the charge is kept to a minimum because the per trading period cost is small; and

(c) designing the residual charge so that it provides efficient incentives to alter the use of the grid. The objective of the residual charge is to ensure that parties have efficient incentives to avoid peak use of the grid which will help promote efficient use of the grid.

Conclusion

5.8.6 Overall, the Authority considers that its proposal achieves its objective for the TPM to facilitate efficient investment in the electricity industry and efficient operation of the transmission grid, generation (including distributed generation), distribution networks and demand-side management.

Q34.	**Do you agree that the Authority's TPM proposal meets the Authority's objective for the TPM? Explain your answer.**

6. Evaluation of alternative means of achieving the objectives

Key points

The Authority considered the following options in evaluating the alternative methods for establishing charges to recover transmission costs.

Market approaches

a) long-term contracts;

b) capacity rights or offer rights;

c) merchant transmission investment;

Market-like approaches

d) vote-based transmission investment;

Beneficiaries-pay approaches

e) economic models;

f) flow tracing;

g) zonal uniform charges;

Alternative approaches

h) current RCPD charge;

i) MWh charge; and

j) incentive-free MWh charge.

These alternatives are not preferred because they variously are not lawful, are not practicable, deliver lower net benefits or would not facilitate efficient investment in the electricity industry and efficient operation of the grid, generation, distribution and demand-side management.

6.1 Introduction

6.1.1 The previous chapter presented an overview of the options the Authority considered for recovering transmission costs, and then outlined the Authority's proposed approach to the TPM. This chapter provides a more detailed evaluation of the alternative options the Authority considered for recovering transmission costs.

6.1.2 Table 6 provides a summary of the options considered in this chapter for recovering the costs of HVDC and interconnection (except in relation to the PDP). The alternatives to recovery costs for connection, static NRS, and the PDP are not included. The alternative considered for connection is retention of the status quo, for static NRS a range of options were considered by the TPAG, and for the PDP the options are either to retain it or not to not have a PDP.

Table 10: Overview of options to recover HVDC and interconnection costs

Option	Section	Nature of option	Lawful	Practicable	Efficient	Potential to recover costs
Long-term contracts	6.3	Market	Y	N	✓✓	Partially
Capacity rights or offer rights	6.3	Market	Y	N	✓	Partially
Merchant transmission investment	6.3	Market	N	Y	✓✓✓	Partially (new)
Vote-based transmission investment	6.3	Market-like	N	Y	✓✓	Partially (new)
Economic model	6.5	Beneficiaries pay	Y	Y	✓✓	Depends on whether investments are efficient
Flow tracing	6.5	Beneficiaries pay	Y	N	✓	Depends on whether investments are efficient
Zonal uniform charge	6.5	Beneficiaries pay	Y	Y	✓✓	Depends on whether investments are efficient
Current RCPD charge	6.6	Alternative	Y	Y	✓	Yes
MWh charge	6.6	Alternative	Y	Y	✓✓	Yes
Incentive-free	6.6	Alternative	Depends	N	✓	Yes

6.1.3 The Authority is required by section 39(2)(c) of the Act to evaluate alternative means of achieving the objectives of a proposed Code amendment. Although this paper is an issues paper, the proposals discussed here are intended to form the basis of a Code amendment proposal to which section 39 of the Act will apply. To ensure that the Authority's proposals are robust, the Authority has undertaken in this chapter the analysis of alternatives anticipated by section 39(2)(c) of the Act.

6.2 Alternative approach to connection charges

Retain the status quo for connection charges

6.2.1 Rather than making minor amendments to the TPM to close loopholes the Authority considered the option of retaining the status quo. This was on the basis that the potential for connecting parties to seek to reclassify connection assets as interconnection assets could be managed by Transpower and the connecting party in negotiating contracts for investments undertaken on behalf of the party. This reflects a market-like approach.

6.2.2 This approach is supported by the recently completed agreement that provides a second circuit to improve reliability of supply to Te Awamutu. In that case, the connection customer has accepted that the TPM connection asset definition rules would have the unintended consequence of redefining a number of current connection assets as interconnection assets. This would inadvertently shift connection costs into the interconnection charge.

6.2.3 The connection customer and Transpower are understood to have completed a customer investment contract that reflects the principle of full economic cost recovery from the connection customer for the investment agreed upon. Under the investment contract, no existing connection assets will be reclassified as interconnection assets.

6.2.4 However, there is the potential for connecting parties to hold out against agreeing a customer investment contract with Transpower on the expectation that connection asset replacement investments will be undertaken by Transpower under a capex proposal submitted to the Commerce Commission. This risk, which the Authority considers is significant, means the status quo would not remove the inefficient incentive.

Lawfulness of the status quo for connection charges

6.2.5 The status quo approach to connection charges is lawful.

Practicability of the status quo for connection charges

6.2.6 The Authority considers that retaining the status quo connection charge is practicable even if it may not always be effective.

Assessment of costs and benefits of the status quo for connection charges

6.2.7 The Authority considers that retaining the status quo connection charge would not effectively deal with inefficient behaviour whereby connecting parties may shift connection costs into the interconnection charge.

Potential to recover connection costs under the status quo for connection charges

6.2.8 The Authority considers that retaining the status quo connection charge would not ensure that all connection costs are recovered from the relevant connecting parties because the costs of some connection assets (or parts of them) would be covered by the interconnection charge.

6.3 Alternative market and market-like charges

6.3.1 The following alternative potentially viable market and market-like options (collectively referred to as market-based options) for recovering HVDC and interconnection costs have been considered by the Authority:

(a) long-term contracts;

(b) capacity rights or offer rights;

(c) merchant transmission investment; and

(d) vote-based transmission investment.

Market Option 1: Long-term contracts

6.3.2 A long-term contract option would involve counterparties (a transmission asset owner and a user) willingly entering into a contract spanning many years which sets the terms and conditions of use and the prices associated with that use.

6.3.3 Long-term contracts for the supply of goods or services are typical where capital-intensive, long term and irreversible investments are required to produce and consume goods or services. Absent this feature it would be efficient for parties to simply agree to short-term or spot contracts.

6.3.4 Long-term contracts for capital intensive transmission type projects are typically efficient only when there are a relatively small number of parties. This is because the transactions costs of negotiating contracts with multiple parties can be significant and there is a potential for parties to “free ride” or “hold out” from entering into an agreement. Moreover, these concerns are greater when investments/costs are large and/or the matters addressed are likely to be complex or novel, which is often the case with respect to electricity transmission investment.

Lawfulness of long-term contracts

6.3.5 This option is lawful.

Practicability of long-term contracts

6.3.6 Long-term contracts are a practicable method for recovering the costs of a limited number of HVDC and interconnection assets due to significant transaction costs associated with negotiating agreements and resolving disputes. In particular, long-term contracts would be quite difficult to agree for assets that are available to multiple parties.

Assessment of costs and benefits of long-term contracts

6.3.7 The likely benefits of long-term contracts include:

(a) potential transmission customers would only enter into contracts when the benefit to them of the asset exceeds their private costs. As the full costs of approved transmission services would be paid for by contracting parties that benefited, they would be incentivised to scrutinise the costs before agreeing to the contract; and

(b) providing long-term certainty to counter-parties about the availability of the asset and price paid for using the asset. The benefit would be derived from improved investment certainty, which would promote efficient investment and therefore dynamic efficiency. However, long-term contracts are unlikely to deliver benefits above those available from the current arrangements.

6.3.8 The likely costs of long-term contracts include:

(a) transaction costs for negotiating transmission agreements and for resolving contractual disputes. These costs are likely to be significant for many transmission assets because there are a number of counter parties – e.g. generators, the transmission provider, the distribution networks receiving power, the retailers, and consumers. Negotiating a contract for services (or for an investment) between some or all of these parties would involve high transactions costs because of the differing interests and requirements of the various parties. Long-term contracts are unlikely to be practicable to implement due to the numbers of counterparties involved in the transaction;

(b) implementation costs for Transpower to develop a contractual framework;

(c) barriers to efficient investment. Where transactions costs result in delay or hold-out prevents the negotiation of contracts, transmission, generation and demand-side investments would not proceed even though the benefits exceed the costs;

(d) inefficiently small increments to transmission capacity. The contracting parties that pay for the transmission services would not pay a price greater than their private benefit. Accordingly, transmission assets would more likely be built and funded according to current or immediately foreseeable needs of transmission customers which would lessen the potential to take advantage of economies of scale which characterise transmission investment; and

(e) the life of transmission assets will exceed the life of the organisational structures of many contemporary market participants, thus creating uncertainty about the durability of contracts, with potential future renegotiation costs.

Assessment of suitability of a long-term contract option to recover HVDC and interconnection costs

6.3.9 Long-term contracts without an effective multilateral decision-making process are not considered a viable option for recovering the costs of HVDC and interconnection assets, relative to the status quo and the Authority's proposal for three main reasons. First, the number of counterparties involved will make the transaction costs too high. Second, the potential for parties to "hold out" from agreement or free ride, or both, on other parties' investment decisions would frustrate and impede investment and cost recovery. Third, there will be uncertainty about the durability of contracts in the face of technological or organisational change.

Market Option 2: Capacity rights (and offer rights)

6.3.10 Capacity rights are contractual rights to physical capacity on a transmission line (or lines) for a defined period. A party that wishes to use the line would have to hold a capacity right, the costs of which fund the building, operation and maintenance of the line. A mechanism could be established to allow the secondary trading of capacity rights.

6.3.11 The mechanism that grants capacity rights to the parties seeking rights could take various forms. It could, for example, be based on a first come first served basis, an auction approach, or historical use.

6.3.12 The capacity rights proposal for electricity transmission assets that has been considered in the most detail in New Zealand was that proposed for the HVDC by the New Zealand Institute of Economic Research (NZIER) on behalf of Rio Tinto

Alcan New Zealand Limited.[109] This proposal favoured allocation of capacity rights based on historical use in preference to allocation by auction. This was because NZIER considered that allocation by auction imposed a greater risk of monopolisation of the rights and over-recovery of Transpower's costs of providing the existing link. NZIER proposed that parties holding capacity rights at the time of dispatch be responsible for paying a pro-rata share of Transpower's costs of providing the link.[110]

6.3.13 The NZIER proposal included design suggestions around secondary and spot trading of capacity rights, incorporation of capacity rights into the dispatch process, and capacity rights settlement.[111]

6.3.14 The Authority, and previously the Commission, reviewed the NZIER proposal and identified a number of unresolved issues. The Authority considered that these issues needed to be addressed if capacity rights were to be implemented for the HVDC.

6.3.15 Similar to capacity rights, offer rights involve allocating rights to offer power from a transmission line into the wholesale electricity market in competition with offers from generators in the sending and receiving region of the line. In other words, the line would be treated as a generator (or series of generators if offer rights were held by multiple parties) in the receiving region of the line.

6.3.16 The pattern of dispatch of generators and the use of the line in a trading period would be determined by the SPD model in the same manner as dispatch is determined in the wholesale market at present. The key difference is that the extent of generator dispatch in the sending and receiving ends would depend on the extent to which offer rights in relation to the line cleared.

6.3.17 For the HVDC there could be separate offer rights for capacity in each direction.

6.3.18 Capacity rights and offer rights, using a design similar to that proposed by NZIER on behalf of Rio Tinto, could be applied not just to the HVDC but to interconnection assets where loop flows are not present and where there is a reasonable level of generator competition, including from dispatchable demand. These conditions will not exist for many of the asset classes, however. Loop flows could be dealt with using shift or participation factors. However, participation factors would change every time there is a change in grid configuration. Also, the number of line outages each year means

[109] *A capacity rights regime for the HVDC link,* NZIER report to Rio Tinto Alcan New Zealand Ltd, 22 March 2010.

[110] *Ibid.*

[111] *Ibid.*

this would be a complex and expensive process, and participation factors may change too frequently to form the basis of securing capacity rights.

6.3.19 Holders of offer rights could receive loss and constraint excess arising on the line or, if these were used for funding FTRs, could receive the FTR auction proceeds (although the competition implications of this would need to be considered first). As with capacity rights, rights could be allocated either by auction or on an administrative basis such as by historical injection into the line. Offer rights should be tradable to ensure they are held by those that valued them the most. The costs of the transmission asset would either be paid through auction proceeds or, if offer rights were allocated on an administrative basis, recovered from parties holding offer rights at the time of dispatch.

6.3.20 The key difference between capacity rights and offer rights is that offer rights involve little modification of wholesale market arrangements. As noted by the TPAG when it investigated offer rights in relation to the HVDC, the SPD model would need to be modified to include link offers but in all other respects the operation of the wholesale market would be unchanged. This would be the case in relation to any other line subject to offer rights.

6.3.21 As for capacity rights, offer rights are likely to suit situations where multiple parties are involved with competing interests in the asset, and so an allocation of the rights to benefit from the asset is required. Because they are tradable, offer rights provide flexibility as parties can adjust their holding of offer rights up to the time of dispatch.

6.3.22 Although parties at the sending end of a line subject to offer rights do not need to hold offer rights, if dispatch of their plant would result in power flowing across the line they will be affected by the behaviour of parties holding offer rights. This may result in uncertainty about the extent to which they will be dispatched.

Lawfulness

6.3.23 This option is lawful.

Practicability of capacity and offer rights

6.3.24 The practicability of applying capacity rights and offer rights across the grid is not clear. To the extent these options have been implemented and operated elsewhere, these are limited to a few specific examples, so the ability of the Authority to draw on experience from other jurisdictions is also limited.

6.3.25 Capacity and offer rights would affect the operation of the wholesale market because generator dispatch would depend on the extent parties held capacity or offer rights. The consequences of this are uncertain. Capacity rights would have substantial effects on the wholesale market. Offer rights are likely to have a lesser effect than capacity rights.

Assessment of costs and benefits of capacity and offer rights

6.3.26 The extent to which capacity rights and offer rights would deliver net benefits relative to the status quo and the Authority's proposal depends on whether the available benefits of more efficient investment and improved allocative efficiency exceed the combination of significant transactions costs, dispatch inefficiency, operation and implementation costs, and risks to generation and retail competition.

6.3.27 Capacity rights and offer rights are likely to deliver similar benefits but offer rights are likely to involve lower costs as less modification of the operation of the wholesale market is required, implying that offer rights would be more efficient.

6.3.28 The expected benefits of capacity rights and offer rights are:

(a) Promoting more efficient investment. Transmission, generation, distribution and demand-side investment is likely to only occur where parties are prepared to purchase the necessary rights. This implies that the counterparties expect to derive a private benefit from the investment that is commensurate to the associated charges needed to recover the cost of the investment; and

(b) Promoting more efficient transmission charges. The costs of transmission investments would only be paid by the parties that benefit from the investment. This should improve efficiency.

6.3.29 The expected costs of capacity rights and offer rights are:

(a) transaction costs from auctioning and trading capacity rights (which are not incurred by administrative options, including the Authority's proposed beneficiaries-pay charge). The standardised nature of rights should mean initial transaction costs are lower than for long-term contracts;

(b) implementation costs are likely to be significant due to costs associated with developing systems and expertise required for auctioning and trading rights. Costs of implementing capacity rights across the HVDC alone would be expected to be greater than the Authority's proposed beneficiaries-pays charge and inter-island FTRs. This is because, in addition to the costs of auctioning, clearing and trading infrastructure, there will also be costs involved in altering wholesale market mechanisms including SPD. Additional costs would be incurred if capacity rights were applied across the grid because the auctioning, trading and clearing infrastructure would need to deal with greater complexity and scale. However, costs could be reduced to some degree by using the infrastructure in place for FTRs;

implementation costs would also be greater for participants than the Authority's proposed beneficiaries-pays charge because participants would need to develop the capability to value and trade capacity rights. To some extent, they could utilise expertise and equipment they had put in place for FTRs so this may reduce costs somewhat;

(c) operational costs associated with auctioning/purchasing and trading rights. Operational costs for auctioning, purchasing and trading capacity rights are expected to be greater for both the provider and participants than the Authority's beneficiaries-pay proposal because the latter does not involve the costs of auctioning or trading;

(d) capacity rights could result in inefficient dispatch due to the potential for wholesale price outcomes to enable less efficient generators to offer/be dispatched out of the merit order. This may arise because transactions costs prevent capacity or offer rights being held by the most efficient generators. This would lead to increased investment risk and higher energy costs;

(e) capacity rights are also likely to increase energy and reserve prices, as parties holding capacity rights will need to incorporate the cost of capacity rights in bids and offers in the wholesale market. However, to the extent that capacity rights result in consumers no longer paying transmission charges this would offset any increase in the cost of energy and reserves;

(f) risk of reduced generation competition. Rights provide the ability for generators to control the access of competitors to transmission. Generators subject to a lack of competitive pressure are likely to have the incentives to restrict dispatch by their competitors and limit competition. This risk is likely to be greater if rights are auctioned; and

(g) risk of reduced retail competition. Reduced generation competition could lead to reduced retail competition if it resulted in an increase in basis risk for generator-retailers subject to capacity rights.

6.3.30 As capacity rights and offer rights are likely to involve greater costs than the Authority's proposed beneficiaries-pay charge, the benefits would need to be commensurately greater in order for capacity rights or offer rights to be more efficient than the Authority's proposal. Further, even if other costs were low, both options are unlikely to provide net benefits where generators are subject to a lack of competitive pressure. Accordingly, the Authority considers that its proposal is likely to be more efficient.

6.3.31 However, the Authority's proposed beneficiaries-pay charge arguably provides the foundations for implementing capacity or offer rights in the future if it were considered that this would be efficient. Accordingly, the

Authority considers that its proposed option is consistent with Principle 4 of its Code amendment principles (Preference for Small Scale ‘Trial and Error’ Options).

Assessment of suitability of capacity and offer rights options to recover HVDC and interconnection costs

6.3.32 The competition risks of capacity rights and offer rights means these mechanisms could only be used to recover HVDC and interconnection costs where there is adequate competition in the wholesale market. Where competition is limited an alternative charging mechanism would be required.

6.3.33 The Authority considers that the transactions and implementation costs of capacity and offer rights, combined with potential adverse effects on the wholesale market and competition, means it is very unlikely these options would deliver net benefits.

Market Option 3: Merchant transmission investment

6.3.34 Merchant transmission investment involves the project developer assuming all of the market risk of a transmission investment and seeking to recoup the costs of the investment through either collecting congestion rents on the line, selling FTRs for the congestion rents, or selling capacity or offer rights on the line to enable holders to arbitrage between low-priced and high-priced locations. Merchant transmission investment has been implemented on a limited basis in the United States and Australia.[112]

6.3.35 In the United States, in order to address concerns that capacity rights restrict access to affected lines, the Federal Energy Regulatory Commission (FERC) has allowed developers to assign capacity on these lines to private customers on a contractual basis, with prices established by negotiation, provided all such capacity is offered to all comers in a transparent and non-discriminatory process. More recently, FERC has allowed some capacity to be assigned to “anchor shippers” in order to recover some development costs prior to offering remaining capacity to the market.[113] Similar requirements could be introduced in New Zealand if there were concerns about moving away from open access to the grid as a result of introduction of capacity rights.

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[112] For a discussion on international experience with merchant transmission investment see Compass Lexicon, *Submission of Dennis Carlton, Charles Augustine and Gustavo Bamberger,* report to Meridian Energy, 23 February 2012, Appendix 3 to *Meridian Energy submission on decision-making and economic framework for transmission pricing methodology review,* 24 February 2012.

[113] *Ibid*, pages 21-22.

6.3.36 Merchant transmission investment is an option likely to be best suited to investments where there is significant uncertainty over whether the anticipated benefits of the investment will be realised, which means undertaking the investment is likely to involve a significant degree of speculation. Efficiency implies that the risks of the investment should be borne by the party speculating as they will be the party best placed to manage the risks. Where investment involves greater risk investors are likely to seek higher returns to reflect the lower likelihood that they will be able to recover the costs of their investment relative to less risky investments.

6.3.37 Recent examples of investments that appear to involve significant speculation about the parties that will benefit from the investment include the Reefton to Dobson 110 kV transmission line and the Lower South Island Renewables project. A key justification for the Lower South Island Renewables project was anticipated (renewable) generation growth in the lower South Island.

6.3.38 With both of these projects Transpower was the party that decided to undertake the risky investment. Efficiency considerations suggest that, for these examples, Transpower should be the party that bears the risks associated with these investments.

Lawfulness of merchant transmission investment

6.3.39 Implementing this option would not be lawful. Merchant transmission investment as a charging approach cuts across price-quality regulation of Transpower by the Commerce Commission. The Commerce Act regime provides for Transpower to recover the costs of investments included in the regulated asset base. Accordingly, this option is inconsistent with the requirements of section 32(2)(b) of the Act, which prevents the Code from purporting to do, or regulating, anything that is the responsibility of the Commerce Commission under Parts 3 and 4 of the Commerce Act 1986.

Practicability of merchant transmission investment

6.3.40 The option would not guarantee that Transpower would recover the economic costs of a merchant transmission link, particularly where insufficient parties contracted to use the associated assets.

6.3.41 Notwithstanding this, experience from other countries suggests that merchant transmission investment is a practicable option in certain circumstances.

Assessment of costs and benefits of merchant transmission investment

6.3.42 Merchant transmission investment would promote efficient transmission investment by ensuring that transmission investments proceed where the proponent (Transpower or another party) is able to successfully manage the risks of the investment and convince investors and parties benefiting from the project to invest in or purchase rights necessary to fund the project.

6.3.43 However, transactions costs and uncertainty may prevent efficient projects from proceeding, which would have flow-on effects in terms of investment in generation and load and competition in the generation and retail markets. This suggests that merchant transmission investment may not provide net benefits across the grid but may provide net benefits in some limited situations. Of all the market-based or market-like options considered by the Authority, merchant transmission most directly targets investment risk and best ensures that the party initiating the investment risk has efficient incentives to manage that risk.

6.3.44 In particular, merchant transmission would ensure that transmission investments proceed only where there are counterparties that will derive a private benefit from the investment.

Potential to recover HVDC and interconnection costs

6.3.45 Merchant transmission investment is unlikely to be practicably applied across the grid, meaning the approach would not be suitable for recovering all HVDC or interconnection costs.

6.3.46 However, the option is considered likely to effectively promote efficient management of investment risk and could potentially be applied as part of a package of transmission pricing mechanisms to deal with investments where efficient management of investment risk is a significant issue.

Market-like Option 1: Vote-based transmission investment

6.3.47 Vote-based transmission investment links investment approval and charges for the associated transmission assets. The framework consultation paper noted the proposal by the Transport Working Group (TWG),[114] which consisted of:

(a) a decision-making framework for investment in the grid and transmission alternatives, including decision-making procedures that were designed to overcome free-rider problems; and

(b) payments for all upgraded grid assets – connection, interconnection and HVDC assets – would have been on a long-term contractual basis.

[114] Electricity Authority, *Decision-making and economic framework for transmission pricing*, paragraphs 4.3.13 – 4.3.16.

6.3.48 Further, a mechanism was included to address free-rider problems, which were a perceived impediment to the long-term contract-based transmission investment regime in New Zealand that existed prior to regulation of transmission investment.

6.3.49 Similar arrangements have been established in other jurisdictions. In particular, in Argentina the following arrangement applied between 1992 and 2002 to transmission expansion:[115,116]

(a) merchant transmission expansion was allowed with voluntary participant funding;

(b) minor transmission expansion (less than US$2 million) was funded on a regulated basis, with costs assigned either through negotiation or allocated to beneficiaries as determined by the regulator with mandatory participant funding;

(c) major transmission expansion was funded as follows:

  (i) the regulator applied a cost-benefit test of a proposed transmission expansion;

  (ii) the proposed transmission expansion was subject to a vote and for the expansion to proceed at least 30% of beneficiaries must support the proposal and no more than 30% of the beneficiaries can be opponents;

  (iii) if an expansion was approved costs were assigned to beneficiaries on a mandatory basis using an "area of influence" methodology; and

  (iv) accumulated congestion rents were allocated to reduce the costs of construction.

6.3.50 This regime resulted in an expansion of transmission capacity limits of 105% during the period 1993-2003, which was more than sufficient to meet the increase in system demand over the period of over 50 per cent.[117]

6.3.51 A similar regime exists in New York, which consists of:[118]

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[115] Hogan, WW: *Electricity market reform: Market design and the green agenda.* Presentation at New Zealand Electricity Authority, 20 July 2012, page 35.

[116] For further details refer: Littlechild, SC and Skerk, CJ: "Regulation of transmission expansion in Argentina Part I: State ownership, reform and the fourth line", CMI EP 61, 2004, pp 27-28.

[117] *Ibid,* page 56.

[118] Hogan, WW: *Electricity market reform: Market design and the green agenda.* Presentation at New Zealand Electricity Authority, 20 July 2012, page 37.

(a) beneficiaries pay;

(b) inclusion of participant funded expansion;

(c) regulated transmission investment provided a supermajority (80%) of the weighted vote of beneficiaries support the investment; and

(d) expansions are awarded incremental FTRs.

6.3.52 The TWG, Argentinian, and New York approaches promote efficient transmission investment by ensuring that transmission investment only proceeds where the beneficiaries are willing to pay but at the same time providing a mechanism that overcomes incentives parties may have to either free ride on or hold out from agreement to the investment. The success of these approaches relies on the effectiveness of the identification of beneficiaries and the determination of benefit. However, the practical results of the Argentinian regime suggest that it is practical to successfully identify beneficiaries and ensure that efficient transmission expansion occurs.

Lawfulness of vote-based transmission investment

6.3.53 Vote-based transmission investment cannot be implemented under the Code. The implementation by the Authority of a market-like approach that gave decision-rights for the parties paying the associated transmission charges cuts across the Commerce Commission price-quality regulation of Transpower and the investment approval regime. As such, adopting a vote-based transmission investment option through the TPM is contrary to section 32(2)(b) of the Electricity Industry Act 2010.

Practicability of vote-based transmission investment

6.3.54 The introduction of vote-based transmission investment appears practicable, based on the experiences from other countries. The key practical issues are the development of methods to identify beneficiaries and to identify their private benefit.

Assessment of costs and benefits of vote-based transmission investment

6.3.55 Vote-based market-like approaches appear to provide a relatively low cost but efficient means of promoting efficient transmission investment.

6.3.56 Transmission investment would only occur where a significant majority of beneficiaries considered the charges were no greater than their private benefit, which would help promote efficient investment. Further, fixing the charge in advance of the investment would provide certainty about the costs involved, which would also promote efficient investment where investment decisions depended on beneficiary identification mechanisms and transmission investment.

6.3.57 Identification of beneficiaries could, though, involve significant transactions costs, given the incentives for potential beneficiaries to minimise transmission charges. However, the ability to vote against a transmission investment may dilute these incentives somewhat.

6.3.58 A further risk and cost is that fixing transmission charges prior to an investment means the charges may not be sufficiently flexible to take into account changing circumstances of individual parties, such as a substantial reduction of demand for transmission services. However, the Authority considers that these risks could be successfully managed through, for example, the provisions of the long-term contracts allowing for such flexibility, as shown by the experience in practice of this approach in Argentina.

6.3.59 The likely benefits of vote-based transmission investment are:

(a) more efficient investment. Transmission, generation and major-user investment would only occur where there were sufficient counterparties willing to pay for an investment, as indicated through voting for or voting against the investment; and

(b) more efficient prices for transmission customers paying for core grid.

6.3.60 The likely costs of vote-based transmission investment are:

(a) transaction costs associated with determining the parties that would benefit from a transmission investment and identifying their private benefit. These would be greater than the Authority's beneficiaries-pay proposal unless it was possible to take a similar approach of utilising a wholesale market or similar model already used and accepted by participants;

(b) implementation costs associated with developing methods for determining private benefit and voting. These costs would be lower than the Authority's proposal if they were incurred only prior to an investment and not on an on-going basis;

(c) operational costs for applying methods for determining private benefit and implementing voting; and

(d) potential for inefficient investment decisions still exists despite the provision of a multilateral decision-making framework. Efficient investment might not occur because sufficient parties vote against the investment going ahead or insufficient parties vote in its favour.

This would have flow-on effects on generation investment and direct-connect major user investment.

Potential to recover HVDC and interconnection costs

6.3.61 As the experience from Argentina indicates, a vote-based transmission investment approach could be applied to all significant new investments across the transmission grid. However, the option would not be suitable for recovering costs of sunk transmission investment.

Q35. What comments do you have about the Authority's evaluation of alternative market-based and market-like approaches for the recovery of transmission costs?

6.4 Alternative exacerbators-pay charging options

6.4.1 The Authority identified network reactive support assets as the only situation arising due to an externality and where an exacerbators-pay charging approach should be applied.

6.4.2 The Authority has considered and has relied on the extensive work by the TPAG when it considered charging options for network (static) reactive support assets. The TPAG considered alternatives to a kvar charge, including:

(a) a kvar charge on reactive power draw;

(b) amending the minimum power factor standard in the Connection Code for the upper South Island and upper North Island to unity or leading power factor; and

(c) defining regional static reactive support assets as connection assets.

6.4.3 The Authority notes that the TPAG recommended a kvar charge taking into account feedback through the TPAG's consultation about the alternatives. The Authority considers that the work carried out by the TPAG on network reactive support was robust and remains relevant.

Q36. What comments do you have about the Authority's acceptance of the TPAG's evaluation of alternative exacerbators-pay approaches for the recovery of network reactive support costs?

6.5 Alternative beneficiaries-pay charging options

6.5.1 The Authority identified the following alternative beneficiaries-pay charging options:

(a) using economic models to identify beneficiaries and private benefit;

(b) using flow-tracing to identify beneficiaries and private benefit; and

(c) zonal beneficiaries pay.

Beneficiaries-pay Option 1: Use of economic models to identify beneficiaries and private benefit

6.5.2 This option would involve allocating the costs of an asset to parties on the basis of a modelled estimate of the benefits to parties of the asset being available using economic models rather than using SPD.

6.5.3 A range of methods could be used to estimate the benefits to parties from transmission assets. This could involve methods such as the bottom-up forecast used to estimate the benefits to parties from the HVDC set out in Appendix C.

6.5.4 Another method is described by Hogan (2011) who suggests estimating the benefits to parties from transmission expansion by considering the power exports and imports enabled by the investment.[119] This method uses transmission planning and dispatch models to estimate the future or expected benefit to parties from a transmission investment and charging beneficiaries according to their estimated private benefit. The charge would be fixed in advance of the investment, would apply only to new investments, and would apply for the period required to recover the costs of the investment. Parties paying the charges would be allocated FTRs.

6.5.5 The Hogan method illustrates the trade-off between promoting static efficiency (i.e. ensuring use of the grid is efficient) and dynamic efficiency (promoting efficient investment and innovation). By fixing the charge in advance of the investment, parties cannot alter their behaviour to avoid the charge, which promotes static efficiency. However, a party's actual benefit may turn out to be different from their anticipated benefit so they may end up paying for an asset they do not benefit from. The risk of this is likely to make parties overly cautious in their investment decisions, which would detract from dynamic efficiency. This is a reason why Hogan

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119 Hogan, WW: *Transmission benefits and cost allocation*. Mossavar-Rahmani Center for Business and Government, John F. Kennedy School of Government, Harvard University, May 31, 2011.

suggests allocating FTRs to parties subject to the charge as this would mitigate this problem to some degree.

6.5.6 Another method is to treat assets as a quota restricting trade between regions and identify the beneficiaries from the “trade” restrictions. A range of other methods exist that have been considered in the past that would fall into this category, such as use of the GEM model.

6.5.7 There are a range of possibilities for how economic models could be implemented. Determination of the model could be left to Transpower. This may be appropriate as Transpower is likely to be in a position to have a good understanding of the benefits and likely beneficiaries of an investment. Alternatively, if Transpower was unable to determine the model in a timely manner or if an independent party is considered best place to make the decision, the Authority could determine the model and assumptions.

6.5.8 Another alternative is that Transpower could be required to apply the model to identify the beneficiaries of an investment proposal as part of the new investment process (this option is discussed in more detail and evaluated separately below).

6.5.9 The main advantages with using non-wholesale market models to apply beneficiaries pay are that the model could potentially be applied across the grid to both existing assets and new investments (although this depends on the model) and could be applied to both generation and load. The main disadvantages are determination of the model and parameters are likely to involve significant dispute, accuracy of the determination of beneficiaries will depend on the model and assumptions used, and, depending on design, could affect offer behaviour.

Lawfulness of using economic models

6.5.10 This option is lawful.

Practicability of using economic models

6.5.11 This option could be potentially applied to recover transmission costs across the grid. The main practical issue would be determining what model and parameters should be used, and resolving any disputes about the output of the model.

Assessment of costs and benefits of using economic models

6.5.12 The likely benefits of this option include:

(a) promoting efficient transmission investment through placing stronger incentives on parties identified as beneficiaries to participate in the investment approval and decision-making process;

(b) promoting efficient investment by generation and load since allocating charges to beneficiaries means they will face the transmission cost implications of their investment decisions; and

(c) promoting allocative efficiency through more efficient prices by reducing deadweight loss, as a greater proportion of the costs of transmission assets, which are currently paid for under the interconnection charge, would be paid for by beneficiaries. The reduction in deadweight loss would depend on the extent to which the charge reflects aggregate benefit.

6.5.13 The likely costs of this option are:

(a) implementation costs for both Transpower and participants, including set-up costs involved in implementing the option, such as the costs of computer equipment, any licence costs, and costs of development and testing;

(b) operational costs, including the on-going costs of applying the option to estimate the benefits from transmission assets;

(c) the costs to participants of complying with the charge;

(d) depending on how the charge is applied:

 (i) incentives on parties to alter their use of the grid in order to minimise their exposure to the charge, which may be inefficient. This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy; or

 (ii) a reduction in dynamic efficiency if the charging method results in parties being overly cautious in their investment decisions. This could be partially mitigated by allocating FTRs to parties subject to the charge; and

(e) costs of on-going dispute, though this depends on the model chosen and the extent to which it and the assumptions used accurately identifies and charges beneficiaries.

6.5.14 The option of using economic models is considered superior to the status quo, but inferior to the Authority’s proposal to use SPD to identify beneficiaries and private benefit. This is because, unlike the Authority’s proposal, it would not use direct wholesale market outcomes to determine benefit but rely instead on forecasts and modelling assumptions. Further, the model itself and parameters would have to be determined, rather than utilising an existing model that determines commercial outcomes for participants as with the Authority's beneficiaries-pay proposal.

6.5.15 The option should not involve large costs relative to more complex options, such as capacity rights, and is a pragmatic approach to implementing beneficiaries pay. If a model was used that industry participants were familiar with, such as the generation expansion model (GEM), this should assist in understanding of charges by industry participants.

6.5.16 However, the method for identifying beneficiaries and private benefit would not be directly linked to the monetary benefit derived from the wholesale market and the grid. Consequently, this option would only be preferred if the SPD method proved impracticable.

Potential to recover HVDC and interconnection costs

6.5.17 This option can be applied across the grid on a consistent basis to both existing assets and new investments. It is also a flexible option that could be adapted to determining beneficiaries of a range of investment types so could potentially achieve broader coverage than less flexible options.

6.5.18 As with other beneficiaries-pay options, its coverage of costs should be limited to parties' private benefit. Any costs not covered by the option would therefore need to be covered by a residual charging option.

Beneficiaries-pay Option 2: Using flow tracing to identify beneficiaries and private benefit

6.5.19 This option involves measuring a party's use of an asset as a proxy for the benefit they derive from the asset. Flow tracing involves calculation of the electrical usage of assets by participants.

6.5.20 Flow tracing was investigated by the Electricity Commission.[120] The method involves calculating average participation (AP) factors for each individual asset using data from SPD. The transmission charge applying to each customer would be determined by allocating the costs of each transmission asset according to each customer's AP factor for the asset. It was proposed to apply flow tracing to load only but it could also be applied to generation.

[120] *Transmission Pricing Review: Flow tracing analysis,* 28 June 2010. Available at: http://www.ea.govt.nz/our-work/advisory-working-groups/tptg/7Dec10/.

6.5.21 A key issue with flow tracing is the minimum power flow captured by the flow trace. The solution for this was to establish a minimum threshold use through an asset concentration index (ACI), based on the Herfindahl-Hirschman index, which in essence measures the number of transmission customers sharing the asset.

6.5.22 Flow tracing is problematic because use is a very imperfect proxy for benefit, as in some cases beneficiaries may not be users[121] while in other cases users may not be beneficiaries, such as because use is involuntary. Moreover, flow tracing ignores the main sources of the private benefits from a transmission investment – price effects and the value of non-supply from the grid. Flow tracing therefore provides a poor estimate of benefits and is likely to result in significant dispute.

6.5.23 A further issue with flow tracing is determining the minimum threshold for flow tracing. This is likely to involve significant debate and, potentially, dispute, which would reduce the net benefits from flow tracing.

6.5.24 Flow tracing could cause participants to alter their behaviour in order to minimise their transmission charge. The Electricity Commission suggested calculating ACI values for each half hour in order to minimise any distortion to participant's behaviour on the wholesale market.[122]

6.5.25 Against this though, flow tracing represents an objective method of determining beneficiaries and therefore the level and allocation of transmission charges. It can be applied across the grid. It may also provide a mechanism that could potentially be used to allocate all transmission costs, including those not subject to power flow, such as buildings, to the extent that shares of power flows were a reasonable proxy for the benefit parties derived from these assets. Flow tracing should also be a relatively low cost means of applying beneficiaries pay.

Lawfulness of flow tracing

6.5.26 This option is lawful.

Practicability of using flow tracing

6.5.27 Flow tracing has been found to be a practical mechanism for transmission charging.[123] However, flow tracing does not represent an efficient method

[121] For example, as noted by the TPAG, a generator not using an asset may nevertheless derive benefit from it through the access it provides to the wholesale market.

[122] *Transmission Pricing Review: Flow tracing analysis,* 28 June 2010. Available at: http://www.ea.govt.nz/our-work/advisory-working-groups/tptg/7Dec10/.

[123] *Ibid.*

of identifying beneficiaries and private benefit because the flow of electrons across the grid does not reflect private benefit as it ignores price effects and the costs that result when there is non-supply from the grid, which are the main sources of the private benefits from a transmission investment.

Assessment of costs and benefits of using flow tracing

6.5.28 Overall, flow tracing is a pragmatic and objective mechanism for applying beneficiaries pay, and probably a superior option to the status quo. However, flow tracing is inferior to the Authority's proposed method (and the alternative option of using economic models) because the flow of electrons across the grid provides a poor proxy for benefit. Consequently, using flow tracing is unlikely to result in charges that reflect the actual benefit parties derive from transmission assets, thereby leading to on-going debate about the identification of beneficiaries and private benefit.

6.5.29 The likely benefits of flow tracing are that it:

(a) promotes more efficient transmission investment through placing stronger incentives on parties identified as beneficiaries to participate in the investment approval process. However, flow tracing will not identify beneficiaries as effectively as the SPD method or the option using economic models;

(b) promotes more efficient investment by generation and load as parties identified as beneficiaries will face the transmission cost implications of their investment decisions; and

(c) promotes allocative efficiency through more efficient prices by reducing deadweight loss. This is because a greater proportion of the costs of transmission assets, which are currently paid for under the interconnection charge, would be paid for by beneficiaries. The reduction in deadweight loss would depend on the extent to which flow tracing identifies actual beneficiaries.

6.5.30 The likely costs of this option are:

(a) implementation costs for both Transpower and participants, including set-up costs involved in implementing the option, including computer equipment, any licence costs, development and testing;

(b) operational costs, including the on-going costs of applying flow tracing;

(c) the costs to participants of complying with the charge;

(d) providing incentives on parties to alter their use of the grid in order to minimise their exposure to the charge, which would be inefficient.

This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy;

(e) costs of on-going dispute resulting from the flow trace inaccurately identifying beneficiaries and the benefit parties subject to the charge derive from transmission assets; and

(f) applying flow-tracing to the HVDC would involve too much price volatility.

Potential to recover HVDC and interconnection costs

6.5.31 Flow tracing could be applied across the grid and to both existing and new investments, and provides a method for allocating costs relating to assets not subject to power flows, although it would be necessary to test whether this delivered net benefits. However, the approach previously considered by the Electricity Commission proposed limiting flow tracing to assets currently classed as interconnection assets on the basis that connection assets were covered by contractual arrangements and applying flow tracing to the HVDC would involve too much price volatility.[124]

Beneficiaries-pay Option 3: Zonal beneficiaries pay

6.5.32 This option involves a zonal postage stamp charge with the charge applying in each zone based on a quantitative assessment of the benefit to the zone from transmission assets. Zones could be based on existing transmission zones, existing transmission charging zones, or could be determined quantitatively, such as by flow tracing.

6.5.33 In strict terms, this option is not beneficiaries pay, as the benefit used to determine charges is not that of individual parties but the aggregate benefit to the zone. Rather, this option is intermediate between beneficiaries pay and alternative charging options.

6.5.34 Because the benefit is the aggregate to the zone some parties would inevitably pay more than their private benefit while other parties would pay less, so the charge would be less efficient than other beneficiaries pay options. As with other postage stamp options, the inefficiencies of the charge could be reduced by spreading the charge across more parties by increasing the size of zones. This would mean the charge would have a lower rate, which would reduce parties’ incentives to inefficiently alter their behaviour in order to avoid the charge. This would, however, need to be

[124] *Ibid.*

balanced against inefficiencies resulting from less accurate identification of beneficiaries and more charging of non-beneficiaries.

6.5.35 The uniform charge that would apply could be determined through the existing RCPD method or another method designed to minimise inefficient use of the grid.

6.5.36 Similar options to the zonal beneficiaries-pay option were considered earlier in the TPM review. In particular, the tilted postage stamp option had similarities to the zonal beneficiaries-pay option but did not seek to apply charges based on the benefit parties receive from transmission assets. Instead it sought to signal the transmission costs involved as a result of locating at a particular point on the transmission grid.

6.5.37 Option 3 approximates a beneficiaries-pay charge but avoids the complexity and transactions costs of pure beneficiaries-pay options and therefore there would be an overall lower cost to apply and to administer it.

6.5.38 However, since the charge would apply to all parties within a zone regardless of whether they were in fact beneficiaries some non-beneficiaries may be charged. Further, since the charge would be determined by the benefit to the zone the charge may exceed parties' private benefits. Parties in this situation would have inefficient incentives to disconnect from the grid as a result of the charge.

Lawfulness of zonal beneficiaries pay

6.5.39 This option is lawful.

Practicability of zonal beneficiaries pay

6.5.40 The main practical issue with this option is determining likely beneficiaries, appropriate zones and the charge that should apply. Although it should be reasonably straightforward to undertake all these tasks, it is likely there would be significant dispute over determination of the likely beneficiaries and appropriate zones, which would mean there would be on-going pressure for alteration to the charging approach.

Assessment of costs and benefits of zonal beneficiaries pay

6.5.41 The benefits of zonal beneficiaries pay are, to the extent charges apply to actual beneficiaries and the charge reflects their private benefits:

(a) promoting more efficient transmission investment by increasing incentives on parties facing the charge to scrutinise transmission investments;

(b) promoting more efficient investment by parties subject to the charge as they will take into account the costs of the charge in their investment decisions; and

(c) reducing deadweight loss because a greater proportion of the costs of transmission assets paid under the interconnection charge will be paid for by beneficiaries.

6.5.42 The costs of zonal beneficiaries pay are:

(a) implementation costs for Transpower and participants, including costs of identifying the zones, the likely beneficiaries within the zone and the charge that would apply;

(b) operational costs to Transpower of applying the charge, and costs to participants of complying with the charge;

(c) transaction costs of resolving disputes regarding determination of zonal boundaries;

(d) on-going lobbying costs from parties adversely affected by the charge seeking an alternative charging approach;

(e) deadweight losses as a result of any charging of non-beneficiaries;

(f) costs of inefficient disconnection to the extent beneficiaries are charged more than their private benefit or the costs associated with mechanisms that seek to avoid inefficient disconnection, or both;

(g) to the extent that the charge applied to non-beneficiaries or exceeded willingness to pay, or both, reduction in efficient investment by generation or load, or both, as a result of the charge; and

(h) providing incentives on parties to alter their use of the grid in order to minimise their exposure to the charge, which would be inefficient. This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy.

6.5.43 Overall, the zonal beneficiaries-pay option would provide greater net benefits than purer beneficiaries-pay options only if the implementation and operational costs were significantly lower than other options, actual beneficiaries were charged rather than non-beneficiaries and the charge reasonably reflected beneficiaries' private benefit. However, as some non-beneficiaries would be charged and the charge would not reflect the private benefit of all parties, this could lead to disputes and lobbying about transmission charges that would undermine the durability of a TPM based on zonal beneficiaries pay. Accordingly, this option is likely to have the lowest net benefits of beneficiaries-pay options.

Potential to recover HVDC and interconnection costs

6.5.44 This charge could be readily applied to costs relating to all HVDC and interconnection costs.

Q37.	**Do you agree with the Authority's assessment and conclusions about alternative beneficiaries-pay options for establishing transmission charges to recover HVDC and interconnection costs? Please give reasons for your views.**

6.6 Alternative options for the residual charge

6.6.1 An alternative charging option is canvassed for recovering the costs of the HVDC and interconnection assets because:

(a) a wholesale market model (SPD or vSPD) approach may not recover the full costs of an investment when the capacity provided by that investment is not fully used; and

(b) it is proposed that the wholesale market model (SPD or vSPD) approach would not apply to transmission assets added to the regulated asset base prior to 28 May 2004 apart from pole 2.

6.6.2 The Authority considers that the key principles that an efficient alternative charging option should follow are that:

(a) the option should minimise any inefficient distortion in use of the transmission grid resulting from the imposition of charges; and

(b) the option should ensure the costs, as approved by the Commerce Commission, of providing the transmission grid are fully recovered so future investment is not stifled by concerns by investors that they will not receive a return on their approved investment.

6.6.3 The Authority considered the following alternative options for recovering the residual transmission costs:

(a) status quo – RCPD charge;

(b) MWh charge; and

(c) incentive-free uniform charge.

Residual charge Option 1: Status quo – RCPD charge

6.6.4 Before determining whether other options should be considered for the residual charge, it is appropriate to consider whether the current interconnection charge, calculated on the basis of RCPD, is consistent with the principles set out in paragraph 6.6.2.

6.6.5 The RCPD charge is paid by large consumers directly connected to the grid and by distribution companies. Transpower allocates the interconnection charge to distributors and large consumers based on the customer's contribution to regional coincident peak demand (RCPD). There are four regions: upper and lower North Island and upper and lower South Island. The number of peaks to calculate RCPD is 12 for the upper North Island and upper South Island, and 100 for the lower North Island and lower South Island.

6.6.6 The problem definition identified that the current RCPD allocation of interconnection charges may be inefficient. In particular:

(a) it incentivises what appears to be inefficient demand-side response in the LNI;

(b) it creates a deadweight loss in the tens of millions of dollars (NPV) because it applies to non-beneficiaries and, for some customers, the charge will exceed their private benefit, which provides incentives for disconnection;

(c) it may promote inefficient transmission and generation investment as generators that benefit from investment in interconnection assets do not face the related costs. This means generators have incentives to lobby for transmission investment but lack incentives to seek to minimise costs. Further, since other parties pay interconnection transmission costs, to the extent that generators benefit from this investment but do not contribute to the costs, generators' activities are cross-subsidised; and

(d) distributors may lack incentives to respond to RCPD price signals because of their ability to pass on transmission charges under the Commerce Commission's input methodologies. The evidence supports this to some extent. In particular, some distributors in the UNI do not appear to respond to price signals even though the number of periods used to calculate RCPD for the UNI is intentionally small (12) so that parties facing the charge have strong incentives to limit peak demand. By contrast, distributors in the USI do appear to respond to the peaks. If parties lack incentives to respond to the charge, this limits the extent to which RCPD can promote efficient investment in, and operation of, generation and demand-side resources.

6.6.7 In addition to these issues, another factor that needs to be considered in the design of a residual charge is that if more efficient charging options are applied, parties facing these charges will receive price signals about the cost implications of their activity for investment in the grid. Because these price signals will apply only to beneficiaries (for market, market-like, or beneficiaries-pay charges) or exacerbators (where exacerbators-pay charges are applied) the price signals will be more efficient than under the RCPD methodology. This is because the RCPD approach also charges non-beneficiaries and non-exacerbators.

6.6.8 It would therefore be appropriate for the residual charge to incorporate a price signal only where more efficient charging methods would not be applied to new investments. The previous sections have identified that more efficient options could be applied across the grid, which would allow more efficient price signals for all new investments. Accordingly, there do not appear to be strong reasons for the residual charge to incorporate price signals for more efficient investment.

6.6.9 The Authority proposes that these issues be addressed in designing the residual charge, provided cost-benefit analysis of the proposed charge demonstrates that this would result in net benefits. In particular, the Authority proposes that the residual charge:

(a) would be applied to generation as well as load;

(b) should in principle be applied to electricity retailers as well as direct connect customers; and

(c) should, to the extent possible, avoid inefficiently distorting behaviour if other charges are introduced that provide incentives for more efficient investment.

Residual charge Option 2: MWh charge

6.6.10 An alternative to a residual charge calculated using RCPD would be a MWh charge applied for every MWh of injection or offtake. The rationale for such a charge would be that it would be neutral to different types of generation (peaking versus baseload) and load, and neutral to use of the grid at different times. As a result, it would result in minimal distortion to use of the grid to avoid the charge, as avoidance of the charge would require a reduction in average use of the grid.

6.6.11 The main advantage of the MWh charge is its neutrality to type of investment and time, which means it would avoid distortions across different types of investment and time of use of the grid. The main disadvantage is that it is a fully variable charge, so parties may seek to minimise their overall use of the grid to limit their liability for the charge. This may result in an increase in generators seeking to embed in distribution grids to avoid the charge and investment by load parties to avoid use of the grid, both of which would be inefficient. However, generators' incentives to do this depend on the methodology distributors adopt to charge generators and load for their transmission costs. One way to address this would be to amend the Code to require distributors to charge embedded generators on a comparable basis to the transmission charges those parties would face if they were connected to the grid and not embedded.

Lawfulness of MWh charge

6.6.12 This option is lawful.

Practicability of MWh charge

6.6.13 This option can be applied under the Code. The main implementation issue with a MWh charge is determining the rate of the charge. The difficulty of doing this will depend on the nature of other charges in place.

Assessment of MWh charge

6.6.14 The benefits of a MWh charge are:

(a) it promotes more efficient generation and load investment by reducing inefficient incentives for investment to manage peaks; and

(b) it promotes more efficient use of the grid by reducing incentive for parties to alter their use of the grid to avoid the charge.

6.6.15 The costs of a MWh charge that seeks to reduce peak signals are:

(a) the implementation costs to Transpower for determining rate of the MWh charge (not significant);

(b) the implementation costs to parties subject to MWh charge (not significant);

(c) the operational costs to Transpower of applying the charge (not significant);

(d) the costs to parties complying with the charge (not significant);

(e) the dynamic inefficiency as a result of incentives to reduce the overall use of the grid. Since the charge is levied in all trading periods, this provides an incentive for generators to embed in distribution networks and for load to invest in equipment to avoid use of the grid; and

(f) the allocative inefficiency as a result of incentives to avoid overall use of the grid. Since the charge is levied in all trading periods, this provides an incentive for parties to reduce their overall use of the grid.

6.6.16 Overall, a MWh residual charge would be simple to apply but the extent to which it delivered net benefits would depend on mechanisms applied to reduce incentives for parties to reduce their overall use of the grid. The prudent discount policy with the changes proposed in chapter 5 should be sufficient to limit incentives on generators to embed in distribution grids in order to avoid the charge and to limit incentives on load parties to invest so as to minimise their exposure to the charge.

6.6.17 A MWh charge may also not complement well a beneficiaries-pay charge that calculates charges every trading period using a wholesale market model. It would involve combining two charges calculated on a variable basis, which may increase the overall incentives to act so as to reduce the overall exposure to the charge, which would be inefficient. Changes to the prudent discount policy may be one way this problem could be avoided.

Potential to recover residual transmission costs

6.6.18 This option could be applied across the grid to all costs.

Residual charge Option 3: incentive-free uniform charge

6.6.19 An incentive-free charge is a charge that transmission customers cannot reduce or avoid by altering their behaviour, e.g. charging generators for future interconnection costs based on each generator's share of generation in 2006. As their share of generation in 2006 is an historical fact, generators would not be able to reduce their transmission charges by altering their behaviour in future years.

6.6.20 An incentive-free uniform charge has the added characteristic that the charge is applied uniformly across all parties subject to the charge. For example, each generator in the previous example would be charged the same rate ($/MWh) on their 2006 generation regardless of their location or distance from consumers.

6.6.21 Incentive-free options have been discussed in relation to HVDC charges.[125] One option discussed was applying the charge at a fixed historical point, which meant the parties facing the charge were unable to alter their generation in order to avoid it. A similar approach could be applied for the residual charge. A key problem with this is that the incidence of the charge would be fixed so could not take into account changes in consumption and generation over time. Although this would remove the ability to act so as to avoid the charge, it would undermine

[125] Transmission Pricing Advisory Group, *Transmission pricing analysis: Report to the Electricity Authority,* 31 August 2011.

investment incentives across the electricity industry as investors would be concerned that an incentive-free charge could be applied to their investments in the future. Hence, the costs of an incentive-free charge would be substantial. Because such a charge would undermine investment incentives it would not, in fact, be incentive free. Further, the charge would bear little relation to the ability of a party to pay for it. This option is therefore unlikely to be practicable.

6.6.22 An alternative option is to apply the charge based on historical generation or consumption determined through random sampling. For example, the charge could be based on a random sample of generation and consumption in trading periods over the previous year or longer. The intention would be to sample in a way that it was difficult for parties to predict the load or generation used to determine the charge and, therefore, what their transmission charge would be. This would of course not be effective for parties with constant load or generation. Parties would only be able to avoid the charge by altering their behaviour in all periods in which the charge may be applied. In other words, it may result in parties seeking to reduce their use of the grid on average rather than in particular trading periods.

6.6.23 The ability and incentives to reduce use of the grid is likely to vary. It is likely that a greater proportion of the charge would be paid by parties with a lower ability to avoid use of the grid, which is similar to the status quo. However, unlike the status quo, the charge would be calculated in all trading periods so the benefit of altering behaviour in any one trading period would be lower. (This would also be the case with options such as a MWh charge, which is discussed below.)

6.6.24 A key issue is the frequency of the sampling to establish the charge. Too infrequent sampling could make the charge so unpredictable as to be disruptive. On the other hand, too frequent sampling could result in the charge being so predictable that there was little value in determining the charge through sampling. A balance would therefore need to be struck so that the charge was sufficiently representative of parties' benefit from the grid but not so frequent as to enable prediction of when there was greatest benefit from altering use of the grid to avoid the charge.

6.6.25 Options exist that are intermediate between a "pure" incentive free charge and a charge determined with random sampling. In particular, the charge could be set for an extended period, say three years, based on a random sample of injection or off-take from the grid in a previous period, e.g. samples from a randomly chosen year or years from the past 3-5 years. Such a charge would be likely to have an effect intermediate between the two options: on the one hand it may limit the ability and incentives of parties to alter their use of the grid to avoid the charge, but on the other hand would only partly take into account the changing circumstances of parties subject to the charge.

Lawfulness of incentive-free uniform charge

6.6.26 This option is lawful.

Practicability of incentive-free uniform charge

6.6.27 An incentive-free uniform charge can be applied under the Code and is likely to be relatively straightforward to implement.

6.6.28 However, the incentive-free charge may have little relationship to the ability of a party to pay the charge, which may mean it is impracticable to apply.

Assessment of costs and benefits of incentive-free uniform charge

6.6.29 The benefits of an incentive-free uniform charge are:

(a) it may avoid inefficient use of the grid to avoid the charge; and

(b) it may remove inefficient incentives to invest so as to avoid the charge.

6.6.30 The costs of an incentive-free uniform charge are:

(a) the implementation costs for Transpower of establishing the charge;

(b) the implementation costs for parties subject to the charge;

(c) the operational costs for Transpower of applying the charge;

(d) the costs for participants of complying with the charge;

(e) it would reduce dynamic efficiency through increasing the business risk of parties potentially subject to the charge, which may reduce investment;

(f) to the extent the charge reduced investment, it may reduce competition; and

(g) the costs resulting from on-going lobbying by parties subject to the charge seeking alteration to it, which would be greater by the extent to which the charge diverged from private benefit.

6.6.31 Overall, it is unlikely the benefits of an incentive-free postage stamp charge would exceed the costs.

Potential to recovery residual transmission costs

6.6.32 Incentive-free charges could be applied across the grid to all transmission costs.

7. Proposed Guidelines for Transpower

Key points
The Authority has prepared draft guidelines to be followed by Transpower in preparing a methodology for allocating Transpower's revenues to transmission customers.

7.1 Introduction

7.1.1 Clause 12.89(1)(c) of the Code requires that Transpower must develop its proposed TPM consistent with any guidelines published under clause 12.83(b).

7.1.2 This section sets out proposed guidelines for Transpower to follow in developing a detailed TPM consistent with the proposals in this issues paper. After taking into account submissions on this paper the Authority will determine and publish the guidelines that Transpower would be required to follow in developing the TPM.

7.2 Overall guidance

7.2.1 Transpower should provide an explanatory document suitable for its customers to understand the basis on which it levies charges.

7.2.2 In proposing a detailed pricing methodology in response to the guidelines, Transpower should detail the linkage between its charges for specific assets and its overall expected revenue.

7.2.3 As required by clause 12.79 of the Code, in developing the TPM, Transpower must assess the TPM against the Authority's statutory objective in section 15 of the Act.

7.2.4 Further, clause 12.89 of the Code requires that Transpower must develop its proposed TPM consistent with:

(a) any determination made under Part 4 of the Commerce Act 1986; and

(b) the Authority's objective in section 15 of the Act; and

7.2.5 In addition, the Authority considers that Transpower should develop the TPM so that it is consistent with the Authority's objective in section 15 of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term-benefit of consumers. In particular, amendments to the TPM should facilitate:

(a) efficient investment in the electricity industry through providing incentives so that the right investments occur at the right time and are in the right place. These investments can be in the transmission grid, generation (including distributed generation), distribution networks or demand-side infrastructure to manage electricity consumption; and

(b) efficient operation of the transmission grid, generation (including distributed generation), distribution grids and demand-side management. This means providing incentives so that the day to day operation of transmission, generation, distribution and demand-side management involves an efficient trade-off between reliability and cost.

7.2.6 The Authority considers that, in developing the TPM, Transpower should seek to optimise promoting efficient investment under (a) and efficient operation under (b). However, where Transpower cannot determine an approach that would optimise both efficient investment and efficient operation, Transpower should give priority to promoting efficient investment. This is on the basis that it would be expected to deliver greater efficiency gains and would therefore better achieve the Authority's objective in section 15 of the Act.

7.3 Scope

7.3.1 Consistent with clause 12.77 of the Code, the TPM must provide for the costs incurred by Transpower in relation to approved investments (as defined in Part 1 of the Code) to be recovered under the TPM.

7.3.2 Further, the TPM must be consistent with the purpose of the TPM as set out in clause 12.78 of the Code, which is "to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs of Transpower's services are allocated in accordance with the Authority's objective in section 15 of the Act."

7.4 Connection charges

7.4.1 The current allocation of connection charges under the TPM is generally appropriate but Transpower should develop amendments to the TPM that provide:

(a) that current connection assets remain defined as connection assets until those assets are replaced (at which point a new investment agreement would be required) or decommissioned;

(b) for referral to the Authority to consider and rule on special cases when the provision set out under (a) results in outcomes contrary to promotion of the Authority’s statutory objective.

(c) that replacement assets are valued for charging purposes at the actual replacement project cost;

(d) for a connection customer to refer to the Authority to determine any connection charges the connection customer considers had been set at an unreasonable level as a result of asset replacement;

(e) for a mechanism to alter the charges applying to connection customers, and other charges as necessary, where a determination by the Authority in relation to (d) required changes to the allocation of charges in accordance with the Authority’s determination; and

(f) for allocation of LCE arising on connection assets to be allocated in a manner so as to offset the connection charge applying to each customer.

7.5 Static NRS charges

7.5.1 Transpower should develop a network reactive support charge for static network reactive support assets that would apply to offtake customers. The rate of the charge should be based on the LRMC of grid-connected SRC assets. In determining the rate of the charge, Transpower should develop a method for estimating the LRMC of grid-connected static reactive support assets. The charge applying to each customer should be determined by their average aggregate kvar draw from the grid.

7.5.2 In developing the Static NRS charge, Transpower should note that the Authority intends to amend the Connection Code to require a minimum power factor of 0.95 lagging in all regions.

7.6 Charge for interconnection and HVDC

7.6.1 Transpower should develop a charge consistent with the method set out in Appendix E (SPD method) of this issues paper to recover the costs associated with the following investments (including operating, overhead, and maintenance costs but after deducting any revenue it receives from the NRS charge and the connection charge, and revenue it receives in relation to loss and constraint rentals or FTR auction proceeds arising from assets associated with these investments):

(a) pole 2 of the HVDC; and

(b) assets added to Transpower's regulated asset base with a cost of more than $2m (at the time the assets are added) after 28 May 2004 (the date that Part F of the Electricity Governance Rules 2003 came into force).

7.6.2 The charge should be developed so that:

(a) it would apply to parties assessed as beneficiaries of an investment as determined by the SPD method. The charge should be developed so that it would apply to any party purchasing from or offering to the wholesale market. That is, the charge would apply to embedded generation and load receiving a benefit by virtue of offering to or purchasing from the wholesale market, which they can only do by virtue of their indirect connection to the grid;

(b) the charge applying to a party identified as a beneficiary using the SPD method would be their assessed benefit, which would be determined by:

(i) their share of injection or off-take in each trading period at nodes identified as benefiting from the investment; multiplied by

(ii) their benefit from the asset at each affected node in each trading period according to the method set out in Appendix E.

7.6.3 Transpower should calculate the charge each month for each trading period in the month.

7.7 Residual charge

7.7.1 Transpower should develop a residual charge that would apply to any costs not recovered under the connection charge, Static NRS charge, or the HVDC and interconnection charge calculated using the SPD method. The residual charge should be a charge calculated according to regional coincident peak demand and injection. Transpower should determine the optimal regions for applying the charge. In determining the number of peaks for calculating the charge, Transpower should set this at a level that means parties subject to the charge have incentives for efficient avoidance of peak use of transmission in each region.

7.7.2 Transpower should develop the residual charge so that it would apply to the following parties:

(a) generators;

(b) direct connect customers;

(c) distributors (except where they had elected to opt out of the charge according to the opt-out mechanism described in paragraph 7.7.3 below); and

(d) retailers (where distributors have opted out of the charge),

7.7.3 Transpower should develop the residual charge so that half of the revenue recovered by the residual charge is recovered from load and half from generators.

7.7.4 Transpower should include a provision in the TPM that would provide for distributors to opt out of the residual charge to the extent that they do not benefit from offering to or purchasing from the wholesale electricity market. The opt-out provision should include a requirement that where distributors were considering to opt out of the residual charge they must consult with retailers that may be affected before they make a decision to opt out.

7.7.5 In developing proposals for the residual charge, Transpower should note that the Authority intends to amend the definition of designated transmission customer so that retailers are included in the definition.

7.8 Prudent discount policy

7.8.1 Transpower should develop proposals for amendments to the prudent discount policy so that it:

(a) may apply for the expected life of the asset to which the prudent discount applies; and

(b) applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges but the investment would be inefficient from an economy-wide point of view.

7.8.2 In developing a proposal for 7.8.1(a), Transpower should design the prudent discount policy so that it is able to apply for a period sufficient to ensure that generators do not have incentives to inefficiently disconnect from the grid in order to avoid transmission charges.

Q38. Do you consider that the draft guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? Explain your answer.

Q39. Do you have any suggestions for amendments to the draft guidelines to ensure that they provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option?

7.9 Loss and constraint excess

7.9.1 The Authority intends to codify the current arrangements in which the loss and constraint excess (and in future, surplus financial transmission rights auction proceeds) received by Transpower from the clearing manager is used to offset the components of Transpower's transmission charges that correspond to the origination of the loss and constraint excess. Accordingly, as a Code change is required, the loss and constraint proposal is not incorporated in the guidelines.

8. Draft process for development and approval of TPM

Key points
The Authority has prepared a draft process for development and approval of the TPM.

8.1 Introduction

8.1.1 This chapter sets out the Authority's proposed process for the development and approval of the TPM, in light of the process set out in Part 12 of the Code and the requirements of the Electricity Industry Act 2010.

8.2 Process for development of the TPM

8.2.1 The Authority's proposal to amend the TPM involves extensive changes to the existing TPM. The Authority considers that Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year. The Authority proposes that Transpower should provide the Authority with a project plan for development of the TPM and that this must include Transpower's proposed timeframe and key milestones for development of the TPM.

8.2.2 The Authority considers that the key question about the process that Transpower should address in developing a TPM is whether the process:

(a) should be limited to an internal process within Transpower for development of the methodology; or

(b) should also include an external consultation process by Transpower.

8.2.3 The Authority notes that clause 12.92 of the Code requires the Authority to consult on the proposed TPM. Given this, the Authority does not consider it necessary for Transpower to consult on its proposal for the TPM. However, Transpower may want to consult on key details of its proposal. The Authority considers that this may assist with the successful development and implementation of the TPM. Transpower should identify any planned consultation on aspects of the proposed TPM in the project plan.

8.2.4 The Authority will determine whether the 90-day timeframe referred to in clause 12.88 of the Code (which states that Transpower is required to submit a proposed TPM within 90 days of a written request by the Authority to do so) is appropriate.

8.2.5 The Authority proposes that Transpower present to the Authority how it intends to implement each element of the transmission pricing guidelines. Where relevant, Transpower should demonstrate more than one option for implementing each clause of the guidelines.

8.2.6 The Authority notes that when the Electricity Commission proposed guidelines for development of the TPM in 2004, Transpower was requested to propose how costs related to revenue that was not subject to regulatory review by the Electricity Commission would be determined and allocated.[126] The Electricity Commission's rationale for this was that the TPM is based on asset cost, and so the determination and allocation of costs associated with assets developed without regulatory review may be of interest to stakeholders. Investment approval is now the responsibility of the Commerce Commission. Further, Transpower is now subject to Individual Price-Quality Regulation under Part 4 of the Commerce Act. Given this, the Authority considers that it is not necessary to impose a similar requirement on Transpower to that proposed by the Electricity Commission in 2004.

8.2.7 Accordingly, the Authority proposes that the process that Transpower should follow in development of the TPM is as follows:

(a) Transpower should prepare a project plan and milestones for development of the detailed methodology, and provide this to the Authority for consideration. The project plan should include the timeframe Transpower proposes for development of the TPM that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year;

(b) Transpower should present to the Authority a proposed approach for implementing each element in the transmission pricing guidelines;

(c) where relevant, Transpower should demonstrate more than one option for implementation of each clause of the guidelines; and

(d) Transpower should provide a set of questions regarding the detailed transmission pricing methodology that the Electricity Authority may use in developing consultation material on the transmission pricing methodology proposed by Transpower.

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[126] Electricity Commission: *Process for Transpower to develop the Transmission Pricing Methodology: Consultation Paper,* 22 December 2004.

Q40.	**Do you agree with the Authority's proposed process that Transpower should follow in developing the TPM? Explain your answer.**
Q41.	**Do you agree that the Authority does not need to require Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated? Explain your answer.**
Q42.	**Do you have any suggestions for amendments to the Authority's proposed process that Transpower should follow in its development of the TPM?**
Q43.	**Do you have any comments about the Authority's proposal that Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year?**

8.3 Process for approval of the TPM

8.3.1 Clauses 12.91 to 12.94 of the Code set out a process for approval of the TPM. This includes:

(a) approval of the TPM or referral back to Transpower for resubmission (clause 12.91 (a) and (b));

(b) amendment by the Authority to the TPM resubmitted by Transpower (clause 12.91(c));

(c) publication of the proposed TPM for consultation (clause 12.92). In particular, this clause requires a consultation period of at least 15 business days following publication of the proposed TPM;

(d) consideration of submissions and decision on the proposed TPM (clause 12.93). In particular, this clause requires that the Authority must complete its consideration of submissions and whether to include the TPM in a schedule to part 12 and, if so, the date on which the TPM will take effect;

(e) determination of the commencement date (clause 12.94). This clause requires the Authority to consult with Transpower on the date for commencement of the TPM.

8.3.2 The Authority intends to follow this process for approval of the TPM. The Authority intends, however, to allow a consultation period of six weeks on the proposed TPM (which exceeds the 15 days for consultation allowed for in the Code) , subject to the timetable Transpower submits for development of the TPM, so that the new TPM can be implemented in April 2015.

8.3.3 In addition, as the TPM is part of the Code, in order to amend the TPM, the Authority must comply with the Act, in particular section 39. The Authority will provide more information about the steps that it will take, for example the nature and extent of any consultation, in due course.

Q44.	**Do you agree with the Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower?**

Appendix A Format for submissions

Question No.	General comments in regards to the following questions:	Response
1	What are your views about the materiality of changes in circumstances since the current TPM came into force in 2008?	
2	What comments do you have on the process that the Authority has outlined for developing and approving a new TPM? Describe and explain any variations to the process that you consider desirable.	
3	Do you agree with the Authority's view that the arrangements under the TPM for recovering connection costs are generally efficient? Explain your answer.	
4	What comments do you have about the potential for inefficient outcomes to arise from incentives to shift connection costs into the interconnection charge?	
5	Do you agree that there is the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract? Explain your answer.	
6	Do you consider that there are any other problems with the connection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem.	
7	What comments do you have about the Authority's analysis of the private benefits deriving from the HDVC link?	

8	What comments do you have about the consequences of the material differences between private benefits from the HVDC link and HVDC charges?	
9	What comments do you have about the Authority's analysis of the costs of inefficient generation investment resulting from the HVDC charge?	
10	What comments do you have about the Authority's analysis of the costs of inefficient operation of South Island generation resulting from the HVDC charge?	
11	Do you consider that there are any other inefficiencies arising from the HVDC charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the inefficiencies.	
12	What comments do you have about a) the differences (including their materiality) between private benefits from interconnection assets and interconnection charges; and b) the consequences of those material differences?	
13	What comments do you have about the Authority's analysis of the problems with interconnection charges?	
14	Do you consider that there are any other problems with the interconnection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem.	

15	What comments do you have about the Authority's view that a prudent discount policy may be necessary after taking into account the incentives provided by the price components of any revised TPM?	
16	Do you agree there would be efficiency gains from each of the components of the proposal for the connection charge, as outlined in paragraph 5.4.9? Please provide an explanation for your answer.	
17	Do you agree that the proposal will address the problem identified in chapter 4 in relation to the connection charge? Please give reasons for your views.	
18	What comments do you have about the Authority's assessment and conclusions about a kvar charge to recover static reactive support costs?	
19	Do you support: a) introducing a kvar charge based on off-take transmission customers' average aggregate kvar draw from the grid in areas where investment in static reactive support is likely to be required, at times of RCPD, at the long run marginal costs of grid-connected static reactive support investments? b) setting a minimum power factor of 0.95 lagging in the Connection Code for all regions?	
20	Do you consider that there are alternatives to a kvar charge for recovering the static reactive support costs that the Authority has not identified that are practicable, would deliver a net benefit and would recover static reactive support costs? Explain your proposal.	

21	What comments do you have about the Authority's assessment and conclusion about charging options for dynamic reactive support?	
22	What is your position on the Authority's proposal to codify that LCE or residual LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals?	
23	What is your view of the Authority's assessment and conclusions about using the SPD or vSPD model to establish a beneficiaries-pay charge for recovering some or all HVDC and interconnection costs?	
24	Do you agree with the Authority's conclusion that the most efficient beneficiaries-pay charging option for applying to HVDC and interconnection costs is likely to be the SPD method? Please provide an explanation for your answer.	
25	Do you consider that there are beneficiaries-pay options that the Authority has not identified that are practicable, would deliver greater net benefits and would recover HVDC and interconnection costs? Explain your proposal.	
26	Do you agree with the proposal to apply the residual charge to: a) generators and direct-connect major users; b) distributors, except where they opt out from the charge; and c) retailers, were distributors elect to opt out from the charge?	

27	Do you agree with the proposal that distributors may opt out from the residual charge: a) to the extent that they do not benefit from offering interruptible load on the wholesale electricity market; and b) provided they consult with retailers that may be affected before they opt out?	
28	Do you consider that the proposed RCPD/RCPI charge, designed to encourage efficient avoidance of peak regional use of the grid, with half of the residual revenue recovered from load and half from generators, would best complement a beneficiaries-pay charge that calculates charges every trading period using the SPD model? Explain your response.	
29	Do you agree that the RCPD/RCPI charge would best meet the principles for an alternative charging option of: a) minimising the distortion in use of the transmission grid resulting from the imposition of charges; and b) ensuring the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered so future investment is not stifled by concerns by investors that they will not receive a return on their approved investment? Explain your response.	
30	Do you agree that the Authority's preferred option for the residual charge should be an RCPD/RCPI charge designed to encourage efficient avoidance of peak regional use of the grid? Explain your response.	

31	What are your views about amending the existing prudent discount policy to provide that it: a) applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges; and b) may apply for the expected life of the asset to which the prudent discount applies? Explain your response.	
32	Do you agree with the assessment of the economic costs and benefits of the Authority's TPM proposal versus the counterfactual? Explain your answer.	
33	Do you agree with the assessment of the costs and benefits of the TPAG majority proposal against the counterfactual? Explain your answer.	
34	Do you agree that the Authority's TPM proposal meets the Authority's objective? Explain your answer.	
35	What comments do you have about the Authority's evaluation of alternative market-based and market-like approaches for the recovery of transmission costs?	
36	What comments do you have about the Authority's acceptance of the TPAG's evaluation of alternative exacerbators pay approaches for the recovery of network reactive support costs?	
37	Do you agree with the Authority's assessment and conclusions about alternative beneficiaries pay options for establishing transmission charges to recover HVDC and interconnection costs? Please give reasons for your views.	

38	Do you consider that the draft guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? Explain your answer.	
39	Do you have any suggestions for amendments to the draft guidelines to ensure that they provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option?	
40	Do you agree with the Authority's proposed process that Transpower should follow in developing the TPM? Explain your answer.	
41	Do you agree that the Authority does not need to require Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated? Explain your answer.	
42	Do you have any suggestions for amendments to the Authority's proposed process that Transpower should follow in its development of the TPM?	
43	Do you have any comments about the Authority's proposal that Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year?	
44	Do you agree with the Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower?	

Appendix B Overview of the evolution of transmission pricing

Please see separate document attached.

Appendix C Assessment of materiality of problems with HVDC charges under the current TPM

Please see separate document attached.

Appendix D Assessment of materiality of problems with interconnection charges under the current TPM

Please see separate document attached.

Appendix E Using the SPD method to apply beneficiaries pay

Please see separate document attached.

Appendix F Cost-benefit analysis of TPM proposal

Pease see separate document attached.