



ELECTRICITY COMMISSION

Consultation Paper

Proposed Guidelines For Transpower's Pricing Methodology

September 2004

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1. Executive Summary

1. The purpose of this paper is to provide an opportunity for market participants to comment on the guidelines the Commission intends to provide to Transpower in regard to formulating its transmission pricing methodology.
2. The proposed guidelines for Transpower are provided in section 2 of this paper. They cover guidelines for connection charges, the interconnection charge, the HVDC charge, and the prudent discount policy.

Should interconnection charges be postage stamp or location-based?

3. The most significant issue for the Commission has been whether interconnection charges should take the form of 'postage stamp' charges, or whether they should be structured to provide location signals to grid customers.¹ The Commission has received several reports on this matter, and has decided to provide stakeholders with a brief analysis of the key issues on this matter in one document, which forms the bulk of this consultation paper.
4. The Commission believes there are several factors that may undermine the provision of effective location signals from nodal prices and the grid investment test. These are outlined in section 4(c), and include regulatory risks, the lack of long-term FTRs, market power, and incomplete coverage of nodal prices.
5. The rest of this section summarises the options for providing location signals.

Option 1: Rely on nodal pricing and the GIT

6. Under option 1, the Commission would rely on nodal pricing and the grid investment test to provide location signals for generators and load. Alternatives to transmission would not be funded, and charges for the core grid would be postage stamp charges, as is currently the case.
7. The primary advantages of option 1 is that it is simple, provides stability for market participants, and defers until more information is available any decision to adopt location-based charges or regulated funding of alternatives to transmission.
8. The primary weakness of option 1 is that it may result in greater transmission capacity, if nodal pricing and the grid investment test fail to provide effective location signals to new generation and load.
9. At this stage, the balance of advice provided to the Commission favours option 1. The Commission is not aware of empirical evidence of nodal pricing being seriously deficient, and it does not have estimates of the magnitude of any over-build costs.

Option 2: Supplement nodal pricing and the GIT with location charges

10. This option is largely the same as option 1 except postage stamp charges for new investments are replaced by location-based charges based on the causer-pays principle (and are charged only to those increasing demand in the region benefiting from the grid upgrade). As with option 1, there is no regulated funding of alternatives to transmission, and postage stamp charges are used to fund assets used to provide existing transmission services.

¹ Grid charges are called "postage stamp charges" when charges are not based on the distance or location of grid users or customers. The same charge rate applies regardless of whether power is conveyed between generators and consumers in the same location or conveyed from one end of the country to the other.

11. Relative to option 1, the primary advantage of option 2 is that it may reduce grid investment costs, by correcting purported deficiencies in nodal pricing and the grid investment test. It is necessary to determine the source of those deficiencies, and tailor the charging regime to correct them.
12. In practice, the Commission is concerned that location charges will be complex to establish and administer, and it is not clear behaviour would be sufficiently modified to justify them.
13. The Commission is also aware that location charges are controversial, and that parties subject to them face strong incentives to lobby for technical changes to reduce their charges.
14. It is important to appreciate that location charges are not market-determined prices, but rather centrally determined by the Commission and Transpower. This may limit their effectiveness, as regulatory risk may undermine participants' ability to respond to location signals.
15. Further work will be required on location charges if that option is the outcome of the consultation process.

Option 1A: Supplement nodal pricing and GIT with regulated funding of alternatives to transmission

16. Another option is to adopt postage stamp charges and provide location signals to generators and load by funding or mandating approved alternatives to transmission.
17. In principle, the owners of alternatives to transmission may receive regulated funding directly from Transpower (raising revenue through its pricing methodology), or they may be mandated to levy and collect revenue according to an approved transmission pricing methodology. This paper refers to "regulated funding" to capture both approaches.
18. Significant further work is required to determine how alternatives to transmission might be procured, and identifying complications associated with that. The Commission intends to consult on these issues before the end of this year.
19. The Commission is aware that readers may argue for/against option 2 on the basis that it is better/worse than regulated funding of alternatives to transmission. The Commission has therefore decided to provide a high-level discussion of option 1A in this paper, but the option should be treated as hypothetical at this stage.
20. A key rationale for funding or mandating alternatives to transmission is to provide effective contestability for grid investment, and to provide greater certainty for the Commission about investment by providers of alternatives to transmission if grid investment were to be deferred. Regulated funding could also assist entrepreneurs to aggregate small DSM options, which cumulatively could bring large savings in avoided grid expansion costs.
21. As for option 2, it is necessary to determine the source of the market failure problem, quantify it, and then determine how best to correct for it. It will be essential the Commission implements robust methods for determining when regulated funding will alter location decisions, and for treating competitors neutrally; otherwise regulated funding may be provided to parties for decisions they would otherwise have made on purely commercial grounds.

22. The Commission acknowledges that some parties are concerned about the extent to which regulated funding of alternatives to transmission may interfere in the day-to-day workings of the energy and reserves markets. The Commission agrees that effective policies and procedures are required to address these concerns if alternatives to transmission are to be funded or mandated, and is working with TAG on these issues.

Comparative evaluation

23. Section 8 contains an evaluation of the above options against the transmission pricing principles in part F, and against part F requirements to take into account practical considerations, transaction costs, and the desirability of consistency and certainty.

Conclusion

24. The Commission intends providing clear guidance to Transpower regarding the adoption of postage stamp or location charges for investments in the core grid, but at this stage has decided to consult stakeholders before deciding which option to recommend to Transpower. The Commission acknowledges that further work will be required on location charges if that option is favoured following the consultation process.

2. Proposed Guidelines for Transpower

Overall guidance

25. Transpower should provide an explanatory document updating "Pricing for Grid Connection Services," at a similar level of detail, and suitable for Transpower's customers to understand the basis on which it levies charges.
26. 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.

Application

27. The Commission notes that rule 12.3.1 of section III of part F requires the provision of a comprehensive plan for asset management and operation of the grid. Accordingly the pricing methodology is to apply to the revenue required to meet all of Transpower's costs in providing transmission assets approved as part of a grid upgrade plan.

Connection charges

28. A deep connection² definition of connection assets should be consistently applied.
29. The costs of connection assets are to be recovered directly from those connected to them.
30. Where there is more than one party connected to a single point then the costs should be allocated among them on a peak demand or injection basis.

Interconnection charges

31. Charges for *existing* core grid assets should be on a postage stamp basis. This is similar to current interconnection charges.
32. At this stage the Commission has not decided whether charges for *new* investments in the core grid should be on a postage stamp or location basis, and intends making that decision after consulting on this document.
33. Transpower should review the existing basis on which it calculates the interconnection charge at a grid exit point. Specifically, Transpower should review whether using the 12 highest half-hour offtake peaks in the 12 months up to and including the current month is most consistent with the pricing principles in rule 2 of section IV of part F.
34. Transpower should also review whether permitting greater aggregation across GXP loads for the purpose of calculating interconnection charges to encourage peak load management within regions would produce prices more consistent with the pricing principles in rule 2 of section IV of part F.

² The concept of "deep connection" is easiest to understand by considering the case where a generator is connected to a spur line, which is connected to the core grid. One option would be to define the generator's connection to the grid as the point where the generator connects to the spur line. The other option is to define the generator's connection point where the spur line connects to the core grid. In simple terms, deep connection refers to the latter approach. Implementing this concept in practice is more complicated than indicated by this simple example.

HVDC charges

35. Over time Transpower should remove separate charges for the existing HVDC link, and recover all revenue for the core grid through its interconnection charge. The costs of any upgrade of the HVDC link should be recovered via interconnection charges.
36. Charges for the existing HVDC link on South Island generators should be gradually transferred to the HVAC pool, and Transpower should propose options for managing this transition.

Interim part F expenditure

37. The approved costs incurred by Transpower in relation to interim grid expenditure approved under rule 16 of section III of part F should be recovered on the basis of the same pricing methodology for connection and interconnection assets, as appropriate.

Other

38. A prudent discount policy should be adopted to ensure that inefficient by-pass of the existing grid does not occur.
39. Overall transitional arrangements should be proposed where revision of the methodology leads to an increase or decrease in current charges.

3. Introduction

a) The purpose and scope of this paper

Part F requirements

40. Rule 4 of section IV of Part F of the Electricity Governance Rules (“the rules”) requires the Commission to provide guidelines to Transpower in regard to formulating its transmission pricing methodology. Rule 7.2.1 of section IV of part F sets out the basis on which Transpower must develop its proposed pricing methodology, and rule 8.1.2 gives the Commission authority to adjust the proposed methodology to ensure it adequately conforms to the requirements of rule 7.2.1.

The process followed by the Commission

41. The Commission engaged Frontier Economics to prepare an issues paper, recommending guidelines for it to consider.³ The Commission considered the issues thoroughly, and sought advice from the Transmission Advisory Group (TAG),⁴ the Transmission Pricing Advisory Group (TPAG),⁵ and from COVEC Limited.⁶
42. The proposed guidelines for Transpower are provided in section 2 of this paper. They cover guidelines for connection charges, the interconnection charge, the HVDC charge, and a prudent discount scheme.
43. The most significant issue for the Commission has been whether interconnection charges should take the form of ‘postage stamp’ charges, or whether they should be structured to provide location signals to grid customers. The Commission has found the discussion in all the reports particularly useful on this matter, and has decided to provide stakeholders with a brief analysis of the key issues on this matter in one document, which forms the bulk of this paper.

The purpose of this paper

44. The purpose of this paper is to provide an opportunity for market participants to comment on the guidelines the Commission intends to provide to Transpower in regard to formulating its transmission pricing methodology.
45. For the purposes of consultation, the Commission agrees with Frontier’s recommendations in regard to connection charges, the HVDC charge, and the prudent discount policy, although it does not necessarily agree with their analysis in all cases.
46. With respect to interconnection charges, the Commission refers readers to sections 4-8 of this consultation document for a discussion of the issues considered by the Commission. Readers should also refer to Frontier’s report and to the other reports provided to the Commission on these matters, for further discussion of these issues.

³ “Transmission Pricing Methodology – Options and Guidelines,” Frontier Economics, Final Draft Issues Paper, 28 June 2004. See www.electricitycommission.government.nz/advisory/transmission/draft-reports.html.

⁴ TAG provided two reports to the Commission: “Comments on Transmission Issues Papers,” 6 August 2004; and “Further Comments on Funding Transmission Alternatives,” 17 August 2004.

⁵ “Transmission Pricing Methodology Issues – Comments,” 6 August 2004.

⁶ “Locational Signals for New Investment,” Covec, Draft Report, August 2004.

b) Links to the Commission's overall work program

47. The Commission's framework for transmission pricing is closely linked to the approach it intends to adopt for the statement of opportunities and the grid investment test. These links are discussed at a high level in section 4(b).
48. A key component of the transmission pricing framework is the role nodal pricing, and FTRs, play in providing investment and location signals to generators and consumers. As indicated in section 5, reforms to the wholesale market and hedge markets may carry implications for the type of transmission pricing methodology that should be adopted. Transmission pricing needs to be appropriately integrated with market arrangements to provide appropriate signals for transmission investment as well as generation and load.
49. There are also linkages between transmission pricing and security of supply policy. A robust and transparent framework for transmission pricing and investment is important to provide market participants confidence to invest in generation and demand side management options, which are important for bringing adequate supply to market. Conversely, security of supply policy may affect nodal prices, which may affect optimal transmission pricing.

c) Submission requirements

50. The Commission would like to invite submissions to the Commission on the proposal and in answer to the specific questions by **5pm on 5 November 2004**. Please note that because of the statutory timing obligations of the Commission, submissions received after this date may not be able to be considered.
51. The Commission's preference is to receive submissions in electronic form (Microsoft Word format and pdf) and to receive one hard copy of the electronic version.
52. The electronic version should be emailed with the phrase "Submission on proposed guidelines for Transpower's pricing methodology" in the subject header to info@electricitycommission.govt.nz, and one hard copy of the submission should be posted to the address below.

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53. The Commission will acknowledge receipt of all submissions. Please contact Jenny Walton if you do not receive electronic acknowledgement of your submission within 2 business days.
54. *Submissions should be provided in the format shown in appendix 5. Your submission is likely to be made publicly available on the Commission's website. Submitters should indicate any documents attached in support of the submission in a covering letter, and indicate clearly confidential information provided to the Commission.*

55. All information provided to the Commission is subject to the Official Information Act 1982.

d) Commonly used acronyms

FTRs	Financial Transmission Rights
GIT	Grid Investment Test
GPA	Grid Planning Assumptions
GPS	Government Policy Statement
GXP	Grid Exit Point
LRMC	Long Run Marginal Cost
NPV	Net Present Value
RFP	Request For Proposal
SOO	Statement of Opportunities
SPD	Scheduling, Pricing, and Dispatch model
SRMC	Short Run Marginal Cost
TAs	Transmission Alternatives
TAG	Transmission Advisory Group
TPAG	Transmission Pricing Advisory Group

4. A Policy Framework for Location Signals

a) The central role of nodal pricing

56. A key feature of transmission is that it is difficult to define physical capacity rights to the grid, which makes it difficult to charge carriage fees on a normal basis.
57. Nodal pricing solves the problem of the lack of long-term physical capacity rights by auctioning generator access to the grid on a half-hourly basis. The scheduling, pricing, and dispatch (SPD) model conducts coordinated auctions across all nodes, and determines prices at each node in a manner that ensures nodal price separation reflects the short run marginal cost of transmission when the grid is unconstrained, and the additional cost of local sources of energy when grid constraints are binding.
58. In the absence of large economies of scale, nodal pricing under common carriage provides the same location signals that would be achieved with more normal transport arrangements under contract carriage. Appendix 1 discusses the economic rationale for these results, and the circumstances in which they apply.⁷ Section 4(c) discusses deficiencies that may arise with nodal pricing, which largely arise from the presence of economies of scale in transmission.

Q1: Do you agree that, in the absence of economies of scale, nodal pricing under common carriage provides the same location signals as would be provided with more normal contract arrangements under contract carriage? If not, why not?

Q2: What is the ability of nodal pricing to influence the location of generation and load, and investment in alternatives?

b) The central role of the grid investment test

Economies of scale and monopoly regulation

59. Another key feature of transmission is that grid investment is characterised by substantial economies of scale, as discussed in the Frontier paper. This means that:
- a. Efficient nodal pricing produces *revenue inadequacy*, and so transmission fees are required to make up the shortfall. If dynamically efficient location signals are already being provided by nodal prices then the most efficient option is to adopt the postage stamp approach to transmission fees; and
 - b. Grid providers become natural monopolies, and like any monopoly, would face strong commercial incentives to restrict output to raise prices. In this case, they have incentives to restrict grid capacity to produce excessive loss and constraint rentals. Avoiding these problems requires price regulation or the removal of the profit incentive, or both.
60. The presence of economies of scale carries very significant implications for the role of transmission pricing and the grid investment test, as discussed below.

⁷ The analytical derivation of these results is presented in Paul Joskow and Jean Tirole, "Merchant Transmission Investment," MIT Center for Energy and Environmental Policy Research, March 2004.

Strategic interdependence

61. The presence of large economies of scale for individual line development means that often only large capacity expansions are economic. But large capacity expansions sharply reduce nodal price separation, which could eliminate the pay-offs generators and load expected to receive from making location decisions in response to nodal price signals.
62. This creates a strategic interdependence problem, where the location decisions of grid users depend on Transpower's plans, and Transpower's plans depend on the investment and location decisions of generators and load. The statement of opportunities (SOO) and the grid investment test are intended to address this problem.
63. More generally, the grid investment test should solve the current problem of under-investment in some parts of the grid, such as in the upper South Island, where nodal pricing is not effective. The current perception that Transpower is 'the investor of last resort' will no longer be accurate, as the grid investment test will only mandate grid investment when it is the best option.

Location signals from the SOO and grid investment test

64. The Frontier paper states that application of the grid investment test provides location signals for generation and load. The Commission generally agrees with this view, with the caveat that it is not clear whether the signals are strong enough for load because of the gaming issues discussed below in section 4(c).
65. Compared to the current situation, the Commission believes the SOO and GIT will introduce far greater transparency regarding future nodal price paths and the commercial implications of Transpower's grid upgrade plans. In this sense, nodal pricing and the SOO/GIT are 'pigeon pairs' – that is, both are needed to provide location signals for merchant investors.
66. Figure 1 (next page) outlines the conceptual role of the SOO in providing information about potential investments that may occur. Figure 1 also highlights that the grid investment process provides greater regulatory certainty to investors, as alternatives to transmission will not be committed by investors until the grid upgrade plan confirms the magnitude and timing of grid investments.
67. The SOO makes clear to market participants the Commission's views about future nodal price separation in the absence of certain grid investments or alternatives to transmission. Consistent application of the grid investment test, by Transpower and the Commission, would provide market participants with confidence to predict future grid investment decisions, and therefore predict future nodal price separation.

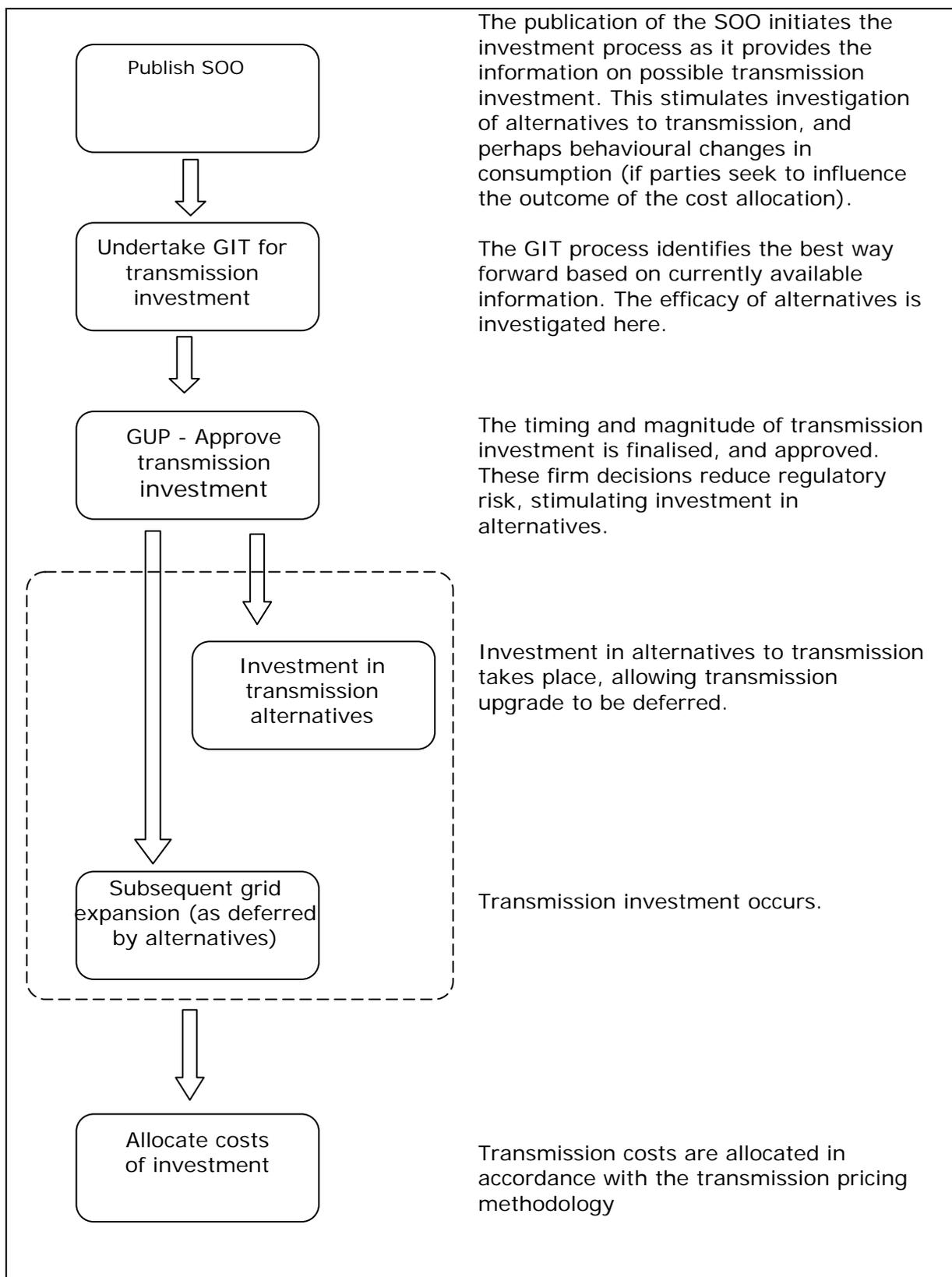
Q3: Do you agree that the grid investment test provides location signals for generation and load, and if not, why not?

Q4: Apart from nodal prices and the application of the grid investment test, are there other location signals for generation or load in the manner in which the electricity market operates in New Zealand? What are they?

c) Potential deficiencies with relying on nodal pricing and the GIT

68. The Commission believes there are several factors that may undermine the provision of effective location signals from nodal pricing and the grid investment test. These are discussed below, and an overview of the broad policy options is discussed in section 4(d).

Figure 1 – Overview of the grid investment process



Regulatory risks

69. The interdependence of grid investment decisions with location decisions for generation and load could undermine the effectiveness of nodal pricing signals. For example, investors seeking to install generation capacity downstream of grid constraints are exposed to the risk that the Commission will be required to change the methodology for the grid investment test.⁸
70. To respond appropriately to nodal price signals, generators need to receive transparent, predictable, and credible signals about future grid upgrade plans. It will also be critical the Commission approves the grid upgrade plan in stages, to provide maximum time for generation and load investments to proceed where they are lower cost than grid expansion.

Gaming incentives for large load

71. The postage stamp approach may create gaming incentives for large load, in some circumstances. This arises because grid expansion often exhibits large economies of scale.
72. For example, consider a consumer deciding where to locate 55 megawatts of new load. Assume the consumer has two feasible location choices: locate in a congested area (e.g. Auckland) currently facing high nodal prices; or locate in an area with spare grid capacity and low nodal prices (e.g. Wellington). Suppose grid capacity into Auckland is such that a 50-megawatt increase in load makes it economically viable to expand grid capacity by 100 megawatts.
73. The consumer in this example has strong incentives to locate his or her new load in Auckland, because that will trigger grid expansion, which will create substantial surplus capacity for many years and lower nodal prices in Auckland until load growth re-congests those circuits. With the costs of grid expansion spread across all transmission customers, the consumer has no incentive to locate his load in Wellington, which is the efficient location from a transmission perspective, in this example. Section 6 discusses practical issues with using location charges to address these concerns.

Gaming incentives for generators

74. Generators may face similar gaming incentives if they do not have to pay grid upgrade costs. Section 6.2.3 of the Frontier paper gave an example where remote generators, relying on grid expansion to get their energy to market, may pre-empt the grid investment test to 'force' uneconomic grid investment. Note the TAG believed these gaming risks were not material.

Large and lumpy generation and load

75. One argument for nodal price failure is that large and lumpy generation and load decisions may collapse nodal price differences, in the same way that large and lumpy grid investment may do.⁹ This would make it difficult for generators and load to earn a commercial return on their investment commensurate with the social benefits of the investment. In theory these problems could be avoided by implementing smaller scale investments, but this will not be economic if there are significant economies of scale. In practice, this is clearly an issue, although it is

⁸ Risk may also arise from rule changes that relax grid constraints (e.g. the development of capacity reserves), or from discretionary changes in system operation.

⁹ See William W. Hogan, "Transmission Market Design," Center for Business and Government, Harvard University, Texas A&M Conference Paper, April 4, 2003, for a discussion of these issues.

not obvious just how large investments would need to be to suffer these problems.

Short-term pricing signals

76. Although nodal pricing solves the problem of lack of physical capacity rights, it does so on a very short-term basis. Investors making long-term investment decisions need to forecast nodal prices for the life of their investments, which is difficult to do accurately or with a high degree of confidence.
77. FTRs may assist by providing longer-term price signals, but it is unlikely FTR contracts will have maturities greater than one or two years. It is not clear that FTRs will greatly assist generators and consumers investing in assets with economic lives of 10 – 30 years.
78. Difficulties with accurately forecasting nodal prices for long periods into the future, and the lack of suitable long-term FTR instruments, may make it difficult for investors in transmission or alternatives to transmission to make timely decisions. If long-term forecasts fluctuate considerably from year-to-year, a consistent trend may not develop until it is too late for investors to invest to avoid high prices and excessive use of high-cost sources of energy. Moreover, nodal prices may collapse once the investment is made.
79. The extent of these problems is not clear, however. For example, consider the case where generators invest downstream of a constraint, which has the effect of forestalling grid investment. Unlike grid investment, however, generation investment doesn't cause nodal prices to collapse as new generators will be able to charge prices that would have occurred during times when the grid would have been constrained. They can do this because otherwise the grid constraints will become binding.¹⁰
80. The short-term nature of nodal pricing may be problematic for large load, however, which was discussed above in regard to gaming incentives. The indicative location-based charging regime presented in section 5 is designed to deal with these issues. The real questions are whether this is a material issue and, if it is, whether the proposed cure is better than the disease, or if there is a better cure.

Incomplete coverage of nodal prices

81. Another issue with nodal pricing is that price separation does not occur at nodes where there is no downstream generation (as demand is not directly bid into the energy market for dispatch). Also, nodal prices don't always reflect the cost of ancillary services purchased through separate contracts, such as the current zone 1 reactive power arrangements.¹¹

Market power

82. Market power can strengthen or weaken location signals from nodal pricing. If generators in a congested area exercise market power, then this may counteract other weaknesses in the nodal pricing signal. Conversely, if generators upstream

¹⁰ Note that generator's would not be able to charge more than the long run marginal cost (LRMC) of the next cheapest entrant, as otherwise they will invite them to enter the market.

¹¹ However, note that some aspects of reliability are reflected in nodal price differences, such as the cost of instantaneous reserves (IR) purchased to cover for generation contingencies. This is because the IR market is co-optimised with the energy market. Most ancillary serves are not co-optimised with energy.

of constraints exercise market power then this will weaken location signals further. This issue is not resolved by the grid investment test.

Implicit price caps

83. Nodal pricing provides real-time signals of binding grid constraints, which can be highly volatile. Volatility arises because grid congestion is highly volatile, but also because it can be costly for generators in congested areas to ramp up quickly for short periods. Congestion may also create opportunities for generators to exercise market power temporarily, which can also create volatility.
84. Extreme price volatility may not be politically sustainable. For example, the Whirinaki power station has already been activated several times in 2004 even though there is no prospect of hydro shortages. Operation of Whirinaki tends to reduce price volatility.

Rental rebates

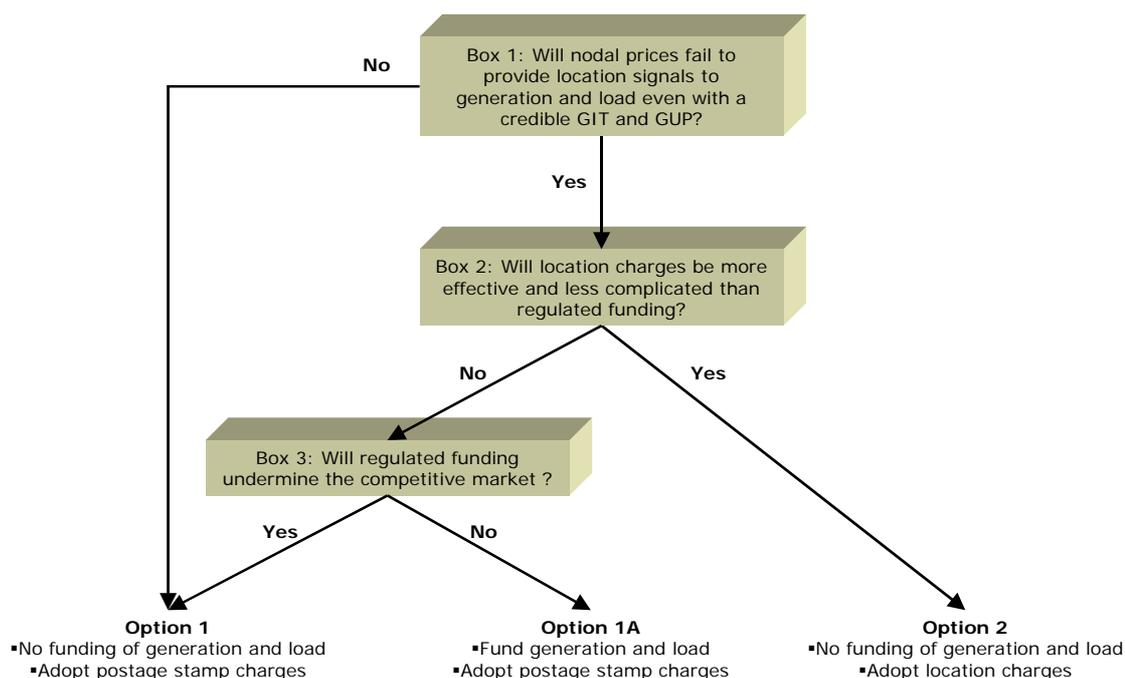
85. Loss and constraint rentals are currently paid to Transpower, who rebates them to distributors, who in turn may rebate them to retailers, who in turn may rebate them to consumers. Rebating of loss and constraint rentals can undermine nodal pricing signals if the amount paid is correlated with energy injections and offtakes.

Q5: Do you agree that the above factors may undermine effective location signals from nodal pricing? Are there any other factors, and how significant are they?

d) Overview of policy options

86. Figure 2 illustrates the various policy options considered by the Commission. All options involve using the grid investment test to make grid investment decisions.

Figure 2: Alternative options for transmission pricing



Option 1: Rely on nodal pricing and the GIT

87. Under option 1, the Commission would rely on nodal pricing and the grid investment test to provide location signals for generators and load. Alternatives to transmission would not be funded, and charges for the core grid would be postage stamp charges. At this stage, the balance of advice provided to the Commission favours option 1. Section 5 of the paper elaborates on this option.

Option 2: Supplement nodal pricing and the GIT with location charges

88. Section 4(c) outlined several reasons why nodal pricing and the grid investment test may not provide fully effective location signals for generators and load. If these concerns are considered serious enough, then charges for the core grid could be used to provide additional location signals. Alternatives to transmission would not receive regulated funding under this option.
89. Section 6 of the paper explores a 'causer pays' approach to location charges, and appendices 2 and 3 discuss two other approaches to levying location charges.

Option 1A: Supplement nodal pricing and GIT with regulated funding of alternatives to transmission

90. An alternative option is to adopt postage stamp charges and provide location signals to generators and load by funding approved alternatives to transmission, or mandating providers of alternatives to transmission to levy and collect charges according to an approved pricing methodology. This option is discussed further in section 7 of this paper.

Q6: Does Figure 2 accurately portray the options faced by the Commission? If not, what aspects should be portrayed differently?

5. Option 1: Rely on Nodal Pricing and the GIT

a) Key components

91. As indicated in section 4, option 1 involves the Commission relying on nodal pricing and the grid investment test to provide location signals for generators and load. Alternatives to transmission would not be funded, and charges for the core grid would be postage stamp charges.
92. This option relies on the assumption that nodal pricing provides adequate location signals, provided grid investment decisions are made in a transparent, robust, and credible manner. It is purported by supporters of this option that although the signals are not perfect, other options may produce worse outcomes. At this stage, the balance of advice provided to the Commission favours option 1.

Future policy developments

93. The Commission's work programme includes the introduction of transmission hedges (e.g. FTRs), and reforms to the wholesale market to improve demand-side participation. Both developments would further improve the effectiveness of location signals from nodal pricing.
94. Another possibility would be for the Commission to regularly publish long-range forecasts of nodal prices, much as the Reserve Bank publishes forecasts of key economic variables, including interest rates and exchange rates. This may mitigate issues with the short-term nature of nodal prices and FTRs, although of course large investors are likely to prepare such forecasts for themselves anyway.

Q7: Would the introduction of transmission hedges and improved demand-side participation improve the effectiveness of location signals from nodal prices?

Q8: Should the Commission regularly publish long-range forecasts of nodal prices?

b) Strengths

Simplicity

95. A key advantage of option 1 is that it is simple to implement, because the current charging regime is a postage stamp regime. The Commission expects some changes will be made to the current regime, such as in regard to the allocation of HVDC revenue requirements, but these are likely to simplify the regime.
96. Implementing the grid investment test is likely to raise complicated and possibly controversial issues, but they are not relevant for this analysis provided the same grid investment test is implemented under both options 1 and 2.
97. Option 1 is also simple to administer on an ongoing basis.

Regulatory stability

98. Adopting the postage stamp approach will provide some stability for market participants during a period of time when large grid investments are under active consideration, and many other aspects of the system are changing. Indeed, the proposal to pool HVDC revenue requirements with the AC core grid is a significant change in itself.

Flexibility

99. Option 1 allows deferral, until more information is available, of any decision to adopt location-based charges or regulated funding of alternatives to transmission. This is important because the Commission will be using the grid investment test to assess the costs and benefits of generation and load investment decisions, and assessing their likelihood of proceeding.¹² In other words, the Commission will have a tool that it can use to assess the efficiency of location decisions, and if it considers location decisions are inefficient, it can proceed to consider location charges or funding of alternatives to transmission.

Q9: Are simplicity, regulatory stability and flexibility advantages of option 1? Are they the only advantages? How significant are they as advantages?

c) Weaknesses

100. The primary weakness of option 1 is that it may result in requiring greater transmission capacity in the future, if nodal pricing and the grid investment test fail to provide effective location signals to new generation and load. But the Commission is not aware of empirical evidence of nodal pricing being seriously deficient, and it does not have estimates of any magnitude of over-build costs.

Weaknesses with the grid investment test

101. At this stage the possibility that nodal pricing and the grid investment test may fail to provide effective location signals is just that – a possibility. The new approach to grid planning and investment is only just being introduced, so it is difficult to determine whether gaming and regulatory risk problems are significant or not. It may well be possible for the Commission to develop anti-gaming rules that largely solve these problems if they turn out to be a material issue.

Weaknesses with nodal pricing

102. The primary sources of nodal price deficiencies would appear to arise from their incomplete coverage, and perhaps the presence of implicit price caps for fear of regulatory or administered intervention. It is questionable that either is a significant issue in New Zealand. There are some examples of lack of nodal price separation (e.g. the upper South Island), but these are very much the exception rather than the rule.
103. Although nodal prices provide only half-hourly signals, large investors have the capability to prepare long-range forecasts of nodal prices for key locations of interest to them. This is no different to any other industry, where investors face considerable uncertainty about the investment climate 5 years out from their investment.

Q10: Is it a weakness of option 1 that it may result in over-building the grid? Do all the factors the Commission has identified operate to undermine the provision of location signals? What is the relative importance in practice of the various factors?

¹² It will need to make such assessments anyway, in forming its views about likely generation and load growth patterns, to decide when to approve grid upgrades.

6. Option 2: Adopt Location Charges

a) Key components

104. This option is largely the same as for option 1 except charges for new investments are replaced by location-based charges based on the causer-pays principle (and are charged only to those increasing demand in the region benefiting from the grid upgrade). As with option 1, there is no funding of alternatives to transmission, and postage stamp charges are used to fund existing investments. Likewise, investments in connection assets would be allocated to connected parties, as in option 1.
105. Relative to option 1, the primary advantage of option 2 is that it may reduce grid investment costs, by correcting purported deficiencies of nodal pricing and the grid investment test. These issues are the converse of those discussed in section 5(c).

b) Indicative model

Overview

106. The indicative model for location charges is based upon a 'causer pays' approach, and is outlined below. The detail of the cost allocation is provided, such that the steps involved in calculating the location charge can be understood. It is important to remember that revenue for existing assets are recovered by postage stamp charges, and only new investments are proposed to send location signals.
107. Appendix 4 provides a numerical example of the 'causer pays' approach to setting location charges.

Cost allocation for the 'causer pays' approach

108. The cost allocation for the 'causer pays' approach is conducted for each grid investment. Over time, the 'pancaking' effect of multiple investments allocated to the same GXPs sends a commensurately stronger signal to those locations.
109. The cost allocation under the 'causer pays' approach is a two-step process. For each investment that is committed it is necessary to:
- a. Identify GXPs that benefit from the investment; and
 - b. Identify the subset of causers from the beneficiaries.

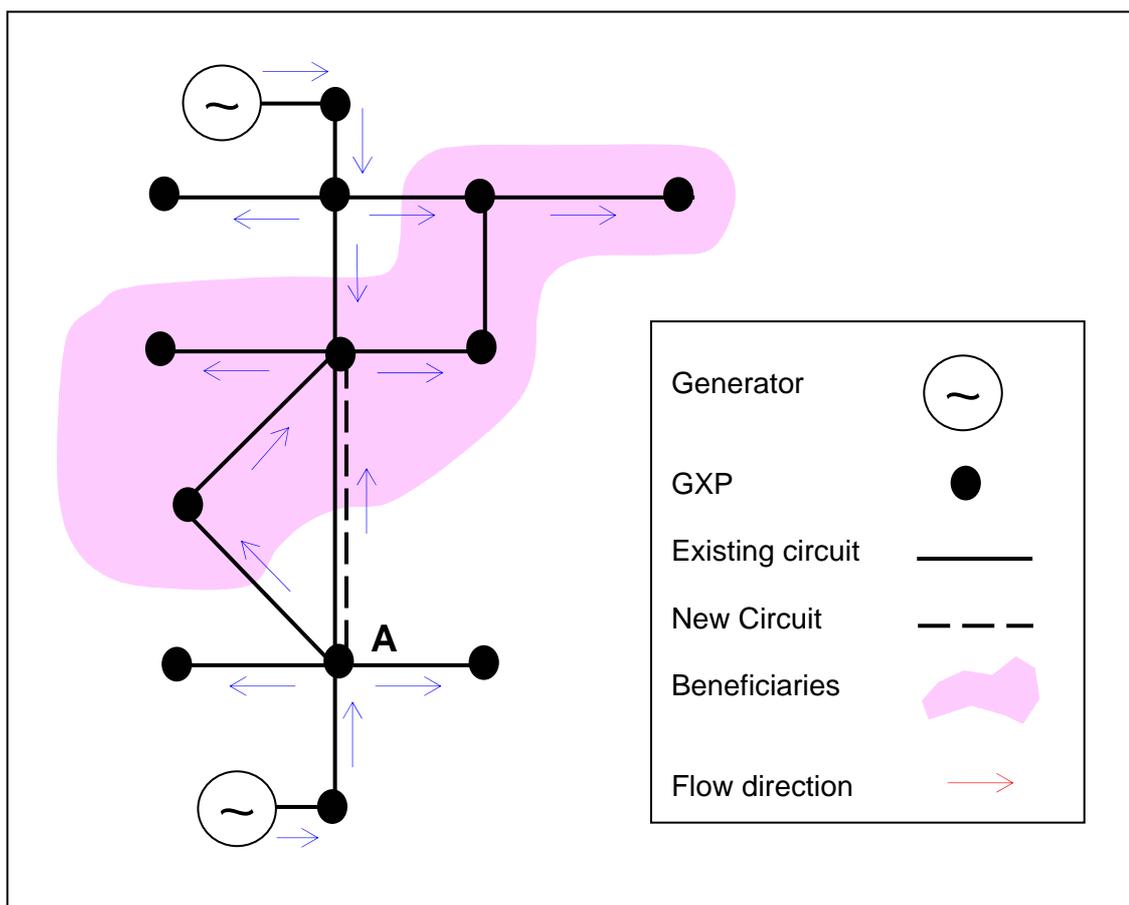
Identifying beneficiaries

110. Figure 3 on the next page shows a hypothetical network, with an associated new investment in transmission. In order to identify beneficiaries of core grid investments, the following algorithm is applied:
- a. Identify power flow directions on the grid based on say 2 years of historical data. For example, identify individual circuits that are more than 70% unidirectional;¹³
 - b. Label all such circuits with the appropriate directional arrow, leaving circuits blank if they have flows that are only 50% -70% unidirectional;

¹³ The value of 70% is chosen arbitrarily here. Detailed analysis would be required to determine the threshold if the algorithm is implemented.

- c. To identify GXPs that benefit from the investment, start at the upstream node of the investment circuit ('A' below), and move stepwise downstream, following all routes until a circuit with an opposing power flow is reached. All GXPs that are passed through in this process are defined to be beneficiaries of the investment; and
- d. If the predominant flows expected on the core grid new investment circuit are only in the range of 50% to 70%, then the beneficiary of that investment would be determined following the above algorithm, though starting from either end of the investment. This may result in all GXPs being identified as beneficiaries, which is likely to be reflective of actual beneficiaries given the bi-directional flow regime.

Figure 3 – Identifying beneficiaries



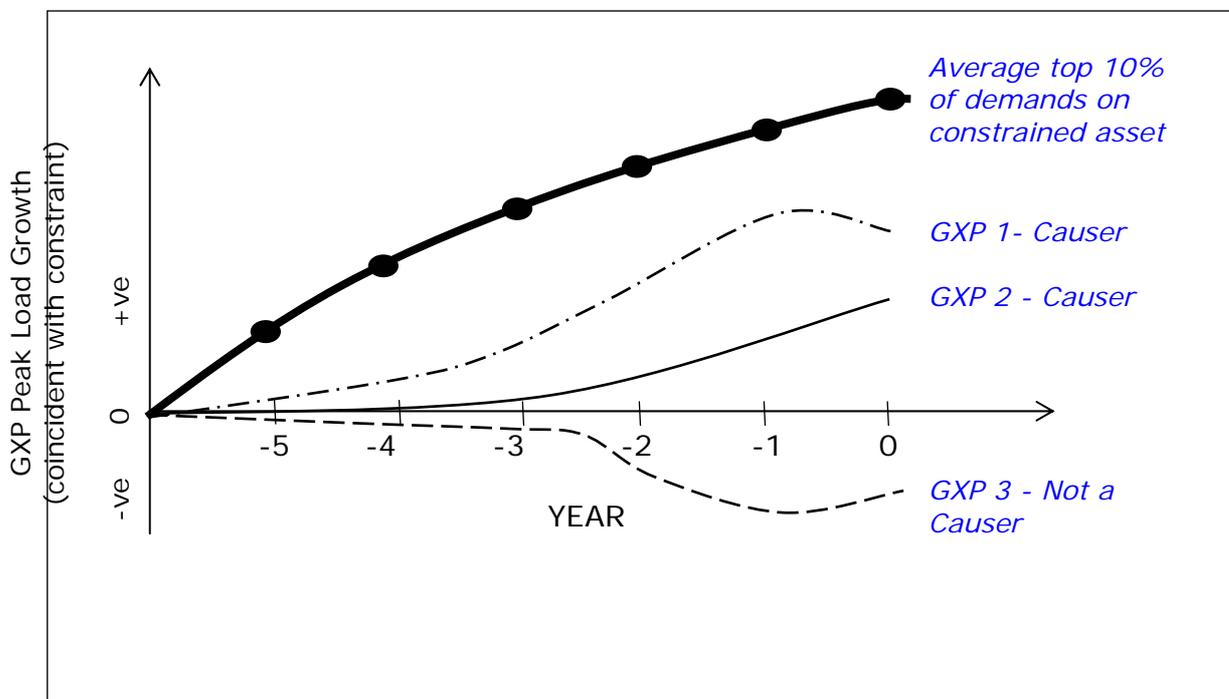
Identifying causers

111. Once the benefiting GXPs are identified, it is necessary to allocate costs amongst the GXPs that are specifically causing the investment. These are called causer GXPs, and are a subset of beneficiary GXPs. Causer GXPs can be defined as those GXPs whose demand during times of constraint, say coincident with the top 10% demands on the asset in question, has increased year on year, say for the last x years. Figure 4 on the next page is drawn on the basis of $x=5$ years.¹⁴

¹⁴ X would need to be long enough to average out yearly variability due to temperature effects, etc. Alternatively, the data could be normalised based on national demand peaks coincident with those times of constraint for the asset in question.

112. Note that this approach allocates cost based on increments of load at each GXP over the last x years, and not on total load at each GXP. Thus, consumers at a causer GXP that respond to information in the SOO about grid investment, and avoid or reduce their load growth at that GXP, can avoid or reduce their charges.

Figure 4 – Identifying causers



Q11: Would the proposed method for location charges be able to be implemented in practice? If not, why not? Are other approaches to location charges more effective?

c) Key design issues

Determining the gap

113. As indicated in section 4(d), the role of location-based grid charges is to correct for purported deficiencies in the overall signalling framework (i.e. location signals provided by nodal pricing and the grid investment test are not sufficient).¹⁵ In other words, location charges are to be used to 'fill the gap' left by nodal pricing and the GIT.
114. The 'gap role' for location charges in New Zealand is very different from the role they have been used for in other jurisdictions, such as in Australia and in England and Wales. Those jurisdictions do not have nodal pricing, and so location charges are intended to be the sole source of location signals. This is easier to design than a 'gap filling' signal required in New Zealand.
115. The following steps are required for the New Zealand regime:

¹⁵ This is not to say that either nodal pricing or the GIT are deficient, just that they are only a part of the overall location signal, it is purported that they are not sufficient without a further signal for the incremental cost of transmission capacity.

- a. Determining the source of the gap. Section 4(c) discussed several potential deficiencies with the location signal from nodal pricing and the grid investment test. It will be necessary to decide which of these deficiencies are real and relevant. This is likely to be difficult given that little empirical evidence is readily available to do so;
- b. Determining the size of the gap. This requires a quantitative assessment of the location signals provided by nodal pricing and the grid investment test, relative to optimal location signals; and
- c. Determining the magnitude of differential grid charges needed to 'fill the gap.'

116. Each of these tasks is complex, and significant judgement may be required.

Q12: What gaps left by nodal pricing and the operation of the grid investment test would location charges of option 2 fill? Would it fill all material gaps? Would it fill them efficiently?

Determining the look-ahead period

117. To be effective, the location charging regime must be forward looking to provide cost signals to generators and consumers well before grid expansion is required. These signals may be informational, or price based. The SOO and the GIT play a key role here, as illustrated in Figure 1. In particular, the provision of forecasts of transmission costs is likely to be important.
118. The appropriate look-ahead period depends on complex judgements about how rapidly generators and load will respond to cost signals, and on judgements about how rapidly spare capacity is depleting. An example of an LRMC based location transmission pricing methodology is given in appendix 3, which illustrates the complexity of these issues.
119. Figure 3 illustrates the approach to identifying beneficiaries, based on average power flow directions. This approach is believed to be feasible because average power flows directions are very stable over time. In addition, because constraints typically only occur for a very small percentage of time, relieving the constraint will not materially affect average flow directions in most cases.¹⁶

Application to generation

120. Section 4 discussed potential deficiencies of nodal pricing in regard to providing location signals, and nearly all of them applied to both generation and load. Correcting these deficiencies via grid charges on generators risks distorting their bidding behaviour in the energy and reserves markets, particularly if location charges are levied on peak demand or growth in peak demand.¹⁷ The indicative location charge regime discussed above does not apply to generation, which means these deficiencies, if they exist, will not be reduced.

d) Effectiveness of location-based charges

Complements nodal pricing

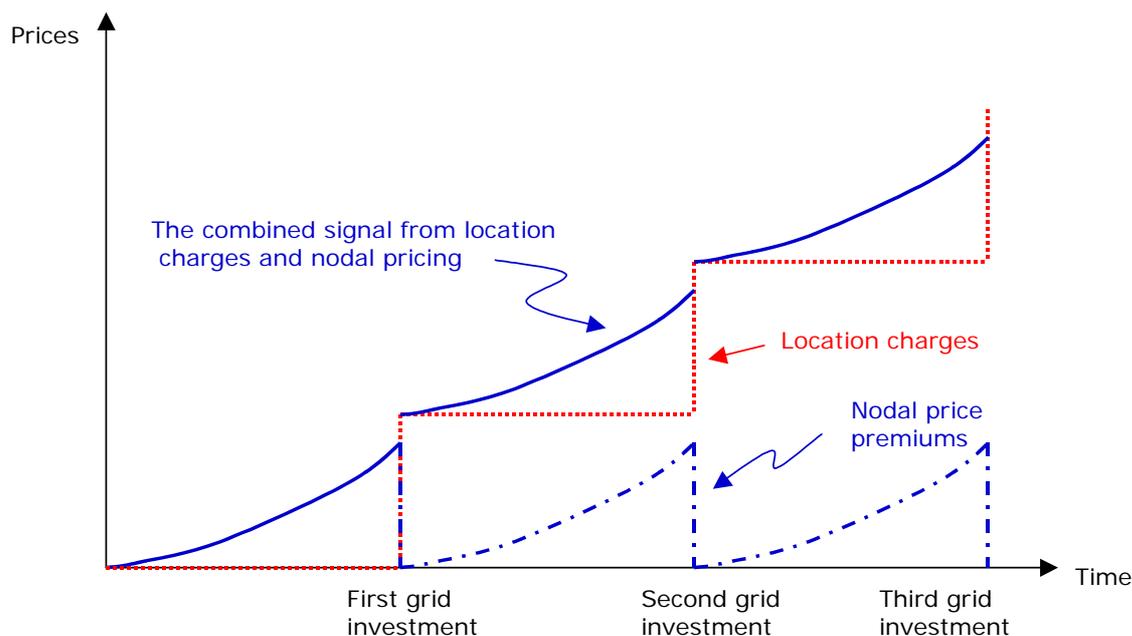
121. Figure 3 illustrates the combined effect of nodal pricing and location charges based on the causer-pays approach. Location charges are zero upon their

¹⁶ The GIT may also by default identify beneficiaries, however this is not clear at this early stage.

¹⁷ The TPAG report discusses these issues in more detail.

introduction. Over time, average nodal price separation becomes larger as grid congestion occurs more frequently and for longer durations. Under the causer-pays methodology, additional location charges are imposed as each additional investment occurs, as illustrated by the step-wise increases in the dotted line in Figure 5. After each investment, nodal price separation collapses to zero, and then reverts to positive premiums as load growth absorbs spare capacity. This demonstrates that location charges complement nodal pricing.

Figure 5: Investment, location charges, and nodal prices



The significance of location charges

122. There is doubt that grid charges are a significant enough cost for many consumers to alter their behaviour. For example, on a postage stamp basis grid charges account for only 10 – 15% of the total cost of delivered electricity across all consumers. If the location component of charges amounted to 50% of average transmission charge, the actual quantum of the price signal would be less than 7% of delivered electricity costs (see also appendix 4).
123. It is difficult to determine at this stage the magnitude of location charges under the causer pays approach, because charges for grid expansion will be levied on a subset of consumers at a subset of GXPs – that is, on parties that increase demand at beneficiary GXPs. It is possible location charges for some customers could exceed 50% of average transmission charges.
124. While it must be said that marginal changes in prices for most goods and services may not alter the behaviour of many consumers, they still perform a valuable role because they affect the behaviour of a few consumers.

Q13: Do respondents see that there will be material differences in the strength of signals to distributors relating to alternatives to transmission and embedded generation, depending on whether option 1 or 2 is implemented?

Other location factors more important for large load

125. Large load investments attract strong public policy interests outside of transmission, because of the significant externality effects they have on local environs. For example, resource consenting issues will typically outweigh concerns about impacts on grid costs.

Strength of the location signal

126. The causer pays approach attributes the full cost of grid expansion to customers causing the need for the expansion. Under this approach the identified party faces the avoided cost of grid expansion, and therefore faces incentives to locate elsewhere on the grid if that is feasible. This is however likely to be highly controversial as causers are highly incentivised to dispute the basis of determining causality.
127. Under the beneficiary approach, the total cost of expanding a component of the grid is spread across all grid users likely to benefit from the investment. This smears the cost of grid expansion, providing weak incentives for beneficiaries to reduce grid usage.¹⁹

Accuracy of the location signal

128. The location signal for causer pays is likely to be much more accurate compared to other options, as it depends only on the accuracy of estimating a single grid expansion cost at a time, and one that will occur in the near term; this requires little forecasting of costs and behaviour. The potential inaccuracy with causer pays is associated largely with the ability to reasonably identify causers.

Rent-seeking incentives

129. Grid charges are not market-determined prices, but rather centrally determined by the Commission and Transpower. This applies to both location and postage stamp charges. The Commission, or the Minister of Energy, can change the methodology without any recourse for investors, provided appropriate consultation processes have been followed.
130. The unpredictability and complexity of location-based charges, and the fact that they apply differential charges to grid users, renders them more susceptible to rent-seeking activity than postage stamp charges. Large parties, in particular, have strong incentives to seek technical changes to the methodology, from which they stand to benefit greatly.²⁰

Credibility of location signals

131. The regulatory nature of grid charges may limit their effectiveness as an instrument to provide location signals. That is to say, the risks of unexpected rule changes and decisions may undermine participants' ability to respond to a price signal, rendering that signal ineffective. Considerable time may need to pass before investors gain confidence that location charges are permanent, and invest on that basis. In the meantime, the Commission will need to assess large grid upgrade proposals that may not be needed within the original timeframes if generators and load make efficient location choices.

¹⁹ Note that cost smearing also occurs under the postage stamp approach to a far greater extent because investment costs are spread over a larger group of users.

²⁰ For example, similar considerations apply in regard to tax policy. New Zealand has operated a relatively simple income tax system since 1986, and it has remained robust to rent-seeking activity. In contrast, the complex system operated prior to 1986 was constantly changed in response to lobbying.

132. Postage stamp charges are also subject to similar risks, but their simplicity and transparency is likely to make them less susceptible to change.

Q14: Are postage-stamp grid charges less susceptible to rent seeking activity and risks of unexpected rule changes and decisions than location-based grid charges?

7. Option 1A: Regulated Funding of Alternatives to Transmission

a) Purpose of this section

133. The previous section discussed issues with designing transmission charges to provide location signals to generators and load. Another approach is to adopt postage stamp charges and to fund or mandate alternatives to transmission. Alternatives to transmission may include investment in local generation, energy efficiency, demand-side management, and augmentation of distribution networks.
134. In principle, alternatives to transmission may receive regulated funding directly from Transpower (raising revenue through its pricing methodology), or they may be mandated to collect revenue according to an approved transmission pricing methodology. This paper uses the term “regulated funding” to capture both approaches.
135. Significant further work is required to determine how alternatives to transmission might be procured, and identifying complications associated with that. Therefore the Commission intends to consult on these issues before the end of this year.
136. The Commission is aware that readers may argue for/against option 2 on the basis that intervention is required, and that option 2 is better/worse than regulated funding of alternatives to transmission. However, it could still be desirable to procure alternatives to transmission for other reasons even if option 2 is selected. The Commission has therefore decided to provide a brief discussion of option 1A in this paper. It notes that the proposed guidelines for Transpower's pricing methodology do not preclude Transpower funding alternatives if the costs of these are approved as part of a grid upgrade plan.
137. The Commission initially viewed regulated funding as an extension of option 1 because option 1 leaves open the possibility of the Commission subsequently approving a policy of funding alternatives to transmission. However, such a policy could also be adopted to cover for the risk that location charges turn out to provide ineffective location signals.

b) The policy context for regulated funding of alternatives to transmission

Part F and other requirements

138. The rules define transmission alternatives as “alternatives to investment in the grid, including investment in local generation, energy efficiency, demand-side management and distribution network augmentation set out in part F.”
139. The current rules do not provide for the Commission or Transpower to fund or mandate alternatives to transmission. Rule 2.2 of section III of part F specifically states that a purpose of section III is to *assist participants* to identify and evaluate investment in alternatives to transmission. No mention is made in part F that the Commission or Transpower should consider funding or contracting for alternatives to transmission.²¹
140. Nevertheless, the draft Government Policy Statement (GPS) issued in September 2004 requires the Commission to consider whether there would be net benefits in

²¹ Part F refers to transmission alternatives in the following rules in section III: 2.2, 6.2, 9.1.2, 11.2, 13.3.3.4, and 14.3.2.2.

providing for a mechanism whereby investments in transmission alternatives receive payments.

Implications for option 1A

141. The rest of this section is written on the presumption that it may be necessary to consider revising the regulations or rules to permit regulated funding of alternatives to transmission. Until such rule changes are made, option 1A should be treated as hypothetical.

c) Requirements for alternatives to transmission under options 1 and 2

Introduction

142. Under either options 1 and 2, the Commission is still required to assist participants to identify and evaluate alternatives to transmission. It is important, therefore, to carefully identify the additional steps and additional information required to fund alternatives to transmission relative to what is required under options 1 and 2.

Requirements under options 1 and 2

143. Under options 1 and 2, the Commission will decide on *grid planning assumptions*. In relation to alternatives to transmission, this requires the Commission to form views about:²³
- a. Committed projects for generation and demand-side management;
 - b. A range of credible future, high-level generation scenarios; and
 - c. A range of demand forecasts.
144. The Commission will also publish *a statement of opportunities*, which requires it to form views about:²⁴
- a. The future performance of the power system under the grid planning assumptions; and
 - b. Identify potential opportunities for alternatives to transmission.
145. The Commission is required by part F to use *the grid investment test* to review alternatives to transmission.²⁵ This requires the Commission to evaluate the benefits and costs of alternatives to transmission, and determine whether they are preferable to Transpower's grid upgrade proposals. The Commission may turn down a grid upgrade proposal if it finds an alternative produces larger net market benefits.

Information requirements under options 1 and 2

146. The Commission will need to acquire detailed information about the investment intentions of market participants, and will need to exercise judgement regarding the likelihood of committed projects proceeding according to plan. It will also need to form views about generic sources of new generation prior to investment

²³ Rule 10.3.1 of section III of part F.

²⁴ Rule 9.1 of section III of part F.

²⁵ Rule 6.2.4 of section III of part F.

announcements by market participants, and form views about their likely timing of entry.²⁶

147. Although part F requires the Commission to assist participants to identify and evaluate alternatives to transmission, the extent to which specific alternatives to transmission must be assessed under the grid investment test is not clear at this stage. The Commission assumes it will be sufficient to prepare generic models of alternatives to transmission, and conduct the grid investment test on that basis.

Decision-making under options 1 and 2

148. Although under options 1 and 2 the Commission is not directly approving or rejecting alternatives to transmission, its decision on Transpower's grid upgrade proposals is almost the same thing. In the presence of nodal pricing, and large economies of scale with grid investment, approving a grid investment removes the commercial drivers for alternatives to transmission. Conversely, rejecting or deferring a grid investment preserves commercial opportunities for alternatives to transmission.²⁷
149. Under options 1 and 2, if the Commission determines that alternatives to transmission are preferable to grid investment, it relies on proponents of alternatives to transmission to finance and install them. In this situation it would be prudent for the Commission to form contingency plans to deal with unexpected delays, and the cost of these should be included in the assessment of alternatives to transmission in the grid investment test.

d) Additional requirements for option 1A

Additional information

150. A decision to fund or mandate alternatives to transmission would increase information requirements for the grid investment test. The Commission or Transpower will need to apply the grid investment test to specific proposals for alternatives to transmission. It will be necessary to assess each proposal on its merits, based on information specific to that proposal.
151. With multiple proposals competing for regulated funding, it will be critical the Commission adopts transparent and rigorous processes for selecting the winning projects, particularly where regulated funding affects competitors in the energy market. Detailed information will be required about the projected costs of each proposal, the services they propose to provide, their technical feasibility, and assurances about the commencement of services.

An example

152. For example, suppose the commercially optimal decision for a generator is to locate a new gas-fired plant in New Plymouth, because forecast nodal price differences are not quite sufficient to justify placing the plant near Auckland.²⁸ The generator may apply for regulated funding to locate the plant near Auckland, to defer grid expansion. In evaluating this proposal the Commission and Transpower will need to compare the additional costs of locating near Auckland against the avoided costs of deferring grid expansion.

²⁶ Section 4.1.2 of Frontier's paper provides a discussion of the options available to the Commission for modelling generic projects.

²⁷ See section 6.2.3 in the Frontier paper for a numerical illustration of this point.

²⁸ Note that transmission charges are not relevant to this decision because they take the form of postage stamp charges under option 1A.

153. This proposal may need to be compared to proposals for a coal-fired plant near Auckland, with coal shipped from the South Island, or to proposals for local demand management. The Commission is likely to be required to consider a wide range of options under the grid investment test, each with their own specifics regarding service availability, reliability, completion timetables, and so on.²⁹

Determining the counterfactual

154. Under option 1A parties that would invest without regulated funding have strong incentives to claim their proposal is not commercially viable without regulated funding.³⁰ For example, a generator may seek funding to locate in a congested area on the basis that forecast nodal price differences after the investment provide insufficient commercial incentive to locate away from its fuel source.
155. In theory the grid investment test addresses this problem by measuring the net benefits of a proposal relative to what would occur if it did not receive funding (“the counterfactual”). But in practice it is difficult to correctly determine the counterfactual, because it involves the Commission judging the likely future actions of commercial parties.
156. Determining the correct counterfactual is critical for the test to accurately estimate the net benefits of regulated funding of alternatives to transmission. If the counterfactual is wrong, the test may yield positive net benefits when in fact they are zero, and may yield zero net benefits when in fact they are positive.

Processes for soliciting alternatives to transmission

157. Publication of the statement of opportunities is the first step to soliciting alternatives to transmission, as it provides the basis for parties to identify investment opportunities.
158. The Commission has not considered how it will formally solicit proposals for alternatives to transmission. One possibility is that proposals could be sought via a formal request for proposal (RFP), so that applicants provide appropriate information in a standard format readily useable by Transpower or the Commission. The RFP process may involve advertising to attract proposals, and perhaps funding or technical assistance to small parties to develop their proposals. A pre-qualification process would probably also be used to reduce proposals to a manageable number.
159. The Commission may also conduct a tender for specified alternatives to transmission, where this would reduce transaction costs for small parties and where services can be well defined in advance. For example, many demand-side management alternatives may be too small to participate directly in the grid investment test, but in aggregate may make a significant contribution to avoiding or deferring grid investment.

Criteria for short-listing proposals

160. Eligibility criteria are required because conducting the grid investment test will be a time-consuming and complicated task, making it impracticable to fully assess all

²⁹ Readers are referred to a paper prepared for the Commission by PB Associates, entitled “Probabilistic Transmission Planning – Comparative Options & Demonstration,” August 2004. The paper demonstrates the trade-offs between grid investment and transmission alternatives when the performance attributes of alternative investments are distinctly different.

³⁰ In contrast, under options 1 and 2 parties have incentives to accurately state their own cost and revenue estimates, as they bear the consequences of their own investments. For example, if they understate their commercial costs then they will end up earning lower returns than normal.

applications. The criteria would need to reflect views about the cost of assessing an additional proposal under the grid investment test versus the probability and cost of not identifying a more efficient outcome. Determining the latter will be difficult to judge in the early stages of the regime, but should become easier as the Commission and Transpower acquire experience with the test.

161. The appropriate approach in this case may be to conduct preliminary cost-benefit analysis of proposals to rank them based on initial calculations of net present value (NPV). The top 3 - 5 proposals for each grid investment region could then be assessed more rigorously under the full grid investment test, and compared with grid expansion.

Regulated funding

162. Proposals yielding the highest positive net present value (NPV) in the test would be eligible for regulated funding. In return, suppliers of alternatives to transmission may be required to agree supply contracts with Transpower, the Commission, or some other contracting party.
163. The Commission has not formally considered the appropriate level of regulated funding for alternatives to transmission. One approach would be for approved projects to receive the amount they bid in the RFP or tender.
164. If the market for alternatives to transmission were competitive, this approach would ensure regulated funding covers only the additional amount needed to secure the availability of the transmission alternative. For example, generators would bid only the amount they need to cover the *net costs* of locating close to load sources (rather than locating near their fuel source). The Commission expects that in most cases only a small amount of the total investment costs of a project would receive regulated funding.

e) Benefits of regulated funding of alternatives to transmission

165. The benefits of funding alternatives to transmission arise from ensuring that alternatives that maximise expected net market benefits do in fact proceed. Funding alternatives would also promote greater contestability and innovation, facilitating small-scale demand responsiveness, and reducing uncertainty. Some of these benefits are discussed in greater detail below.

Contestability and innovation

166. A key benefit of regulated funding is that it provides effective contestability for transmission investment. Transpower effectively has a monopoly on the provision of transmission services, under current arrangements, and so faces weak incentives to innovate and respond to customers' needs and preferences. The encouragement of alternatives to transmission by the Commission should stimulate more innovation by Transpower, and make it more customer focused. It should also stimulate more innovation by potential providers of alternatives to transmission.

Facilitate small-scale demand responsiveness

167. Regulated funding may assist entrepreneurs to aggregate small DSM options, which cumulatively could bring large savings in avoided grid expansion costs. For example, the Commission could conduct tenders for specified services, and funding and technical assistance could be provided for small parties to develop their proposals.

Reduce uncertainty

168. Regulated funding may also strengthen responses to location signals from the grid investment test, by reducing uncertainty for providers of alternatives to transmission. Compared to option 2 where alternatives to transmission bear the risk of unexpected changes to the location-charging regime, regulated funding provides contractual commitments to providers of alternatives – once they win approval via the grid investment test, providers can proceed with confidence they will receive regulated funding.
169. Greater certainty for alternatives to transmission also provides greater certainty for the Commission, because it knows which alternatives are committed to implementation. This should afford the Commission greater confidence to defer grid investments where they are more costly than alternatives to transmission. In contrast, if grid investment is deferred under options 1 and 2 the Commission has to rely on uncertain and uncommitted actions of providers of alternatives to transmission, although achieving timely grid investment may also be uncertain.

f) Effectiveness of regulated funding of alternatives to transmission

Information and incentives

170. Provided nodal pricing and the grid investment test provide accurate and timely location signals, generators and load have the information and incentives to make efficient investment and location decisions. The Commission acknowledges that it is desirable to rely on decentralised decision-making by market participants, as over time this would normally achieve superior outcomes.
171. As for option 2, the economic rationale for regulated funding is premised on nodal pricing and the grid investment test providing insufficient location signals. As for option 2, it is necessary to determine the source of the market failure problem, quantify it, and then determine how best to correct for it.
172. Provided bidding is competitive and the grid investment test is accurately applied, then an RFP or tender process would ensure regulated funding is just sufficient to 'fill the gap' left by deficiencies in nodal pricing.

Accuracy of the location signal

173. In practice the grid investment test could provide inaccurate results, as most of the information used in the grid investment test will be uncertain. Both the Commission and Transpower will need to exercise judgement about a wide range of decisions.
174. The Commission is currently developing high-level policies and procedures for funding or mandating alternatives to transmission, where a key focus is on policies that minimise these risks. Once that work is complete the Commission will be in a better position to judge whether option 1A can materially improve location choices relative those occurring under options 1 and 2.

The timeliness of funding

175. The availability of regulated funding may create incentives for potential providers of alternatives to transmission to delay investment decisions until their proposal can be approved or rejected by the Commission. This should not become a material issue, however, because only a small amount of the funding investors need for their projects is expected to come from regulated sources.

Scale neutrality

176. The compliance costs with regulated funding may be relatively large and fixed with respect to the size of alternatives to transmission, potentially creating barriers to entry for small providers. The Commission may consider ways to address these problems by conducting tenders for specified services, or by allowing regulated funding for entrepreneurs to aggregate small-scale options.

Interference with participation in the energy and reserves markets

177. Contracts for alternatives to transmission will need to specify the services they are expected to provide, and their participation in the energy and reserves markets. This contrasts with the approach in options 1 and 2, where new generators are free to participate in both markets as they see fit.
178. The Commission believes alternatives to transmission could be contracted as grid support ancillary services, similar to other ancillary service arrangements. Such contracts do not appear to have posed significant interference problems to date.

8. Comparative Evaluation

a) Evaluation criteria

Part F pricing principles

179. Rule 2 of section IV of part F specifies the principles the Commission must apply in approving the transmission pricing methodology. It is necessary, therefore, to evaluate options 1 and 2 having regard to the following principles in rule 2:
- 2.1 The costs of connection and use of system should as far as possible be allocated on a user pays basis;
 - 2.2 The pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options;
 - 2.3 Pricing for new generation and load should provide clear locational signals;
 - 2.4 Sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions made by grid users;
 - 2.5 The overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints; and
 - 2.6 Transmission pricing for investment in the grid should recognise the linkages with other elements of market pricing (including the design of the financial transmission rights regime under section V, and any revenues from financial transmission rights).

Static versus dynamic efficiency trade-offs

180. The above principles emphasise static and dynamic efficiency. The Frontier report provides a useful description of static and dynamic efficiency as it applies to transmission, and the report from TPAG elaborates on some of these issues.³²
181. The Commission appreciates there are many aspects of pricing that require a trade-off between both types of efficiency. The Commission believes the primary focus should be on dynamic efficiency, as it is widely accepted in economics that dynamic efficiency dominates static efficiency over the long run. A dynamic efficiency focus is especially important at a time when significant industry investment is required.

Q15: Do you agree with the Commission's assessment that the primary focus should be on dynamic efficiency? If not, what do you think it should be on?

Other considerations

182. Rule 3.1 of section IV requires the Commission to take into account practical considerations, transaction costs, and the desirability of consistency and certainty.

³² In simple terms, static efficiency refers to the efficient operation of the existing network, whereas dynamic efficiency refers to optimal investment to maximise net market benefits in the long term.

³⁴ The reference to connection costs in rule 2.1 is ignored for the purposes of this comparison, as all options propose the same approach to connection charges.

183. Rule 3.2 requires the Commission to resolve conflicts with the pricing principles in rule 2 with the objective of best satisfying the Commission's principal objective. This is:

... ensure that electricity is generated, conveyed, and supplied to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner. (s.172N, Electricity Amendment Act 2001)

b) Comparison of options

184. Table 1 on the next page summarises the analysis in sections 4 – 7, in terms of their consistency with the pricing principles in rule 2 of section IV of part F. Table 2 summarises the practical issues.

Q16: Do you agree with the assessments in Tables 1 & 2 relating to the consistency of the options with the transmission pricing principles and with the practical considerations? If not, what assessments do you think should be changed and why?

Table 1: Evaluation against pricing principles (as specified in rule 2)			
	Option 1	Option 2	Option 1A
<i>Rule 2.1: Costs of use of system allocated on a user pays basis (as far as possible)³⁴</i>	Not quite because grid expansion exhibits economies of scale, which means can't rely on nodal price separation to pay for use of system assets. Option 1 assumes 'postage stamp' charges are used to cover the revenue shortfall. This is a 'flat tax' approach, rather than user pays. ³⁵	Depends on type of location charge regime. Yes if adopt LRMC or causer pays approaches. No if adopt beneficiary pays approach.	Same as option 1. Funding alternatives to transmission does not alter this outcome.
<i>Rule 2.2: Provides strong incentives for beneficiaries of grid investment to identify least cost investment options</i>	Very weak incentives because postage stamp charges smear the costs of grid investment across all grid users regardless of whether they benefit from the investment or not	Depends on type of location charge regime. Strong incentives under LRMC approach. Moderate incentives under causer pays approach because costs spread against causer's share of peak demand. ³⁶	Mixed incentives. Strong incentives for some proponents of alternatives to transmission to identify least cost options, but strong incentives for other proponents to identify options merely to win regulated funding
<i>Rule 2.3: Provides clear location signals for new generation and load</i>	Yes, if believe nodal prices provide sufficient location signals. No, otherwise.	Yes, if location charges accurately fill gap left by nodal prices. No, if believe nodal prices provide sufficient location signals or believe difficult to target location charges at gap.	Yes, if funding accurately fills the gap left by nodal prices. No, if believe nodal prices provide sufficient location signals or believe funding likely to be poorly targeted.
<i>Rule 2.4: Sunk costs are allocated in ways that minimise distortions to production, consumption, and investment decisions made by grid users</i>	Yes, because postage stamp charges apply the same interconnection rate to all sources of peak demand.	Yes, if location charges applied only to new grid investment and postage stamp charges used to recover revenue for existing assets.	Yes, because funding for alternatives to transmission is only in regard to avoiding new grid investment. Postage stamp charges used to recover revenue for existing assets.
<i>Rule 2.5: Overall pricing structure provides incentives to minimise network constraints³⁷</i>	Yes, nodal pricing provides half-hourly incentives to minimise constraints.	Same as for option 1, provided location charges do not interfere with the workings of nodal pricing.	Same as for option 1, provided funding of alternatives to transmission do not interfere with

³⁵ Appendix 1 explains why nodal pricing would fully fund use of system assets if grid expansion exhibited constant returns to scale.

³⁶ Even weaker incentives would be achieved under a beneficiary pays approach as costs are spread against peak demand and against a larger number of parties.

³⁷ The Commission interprets this rule as referring to short term incentives to minimise network constraints, as rule 2.3 covers long-term incentives.

			the workings of nodal pricing.
<i>Rule 2.6: Recognises linkages with other elements of market pricing (e.g. FTRs)</i>	Yes, FTRs are more viable the more transparent and robust is the SOO and GIT.	Same as for option 1, provided location charges do not interfere with the workings of nodal pricing.	Same as for option 1, provided funding does not distort decision-making under the GIT.

	Option 1	Option 2	Option 1A
<i>Minimises transaction costs</i>	Yes, because postage stamp charges are easy for Transpower to calculate and easy for customers to check they have been charged correctly.	No, because location charges are more complicated for Transpower to calculate and may be complicated for customers to check they have been charged correctly.	Yes, in regard to postage stamp charges, but no in regard to funding alternatives to transmission. Transaction costs relating to funding may be large.
<i>Promotes consistency</i>	Yes, by applying the same pricing methodology to existing and new investments. No, if nodal pricing provides insufficient location signals, because then short-term signals achieved through nodal pricing are not consistent with long-term signals provided via grid charges.	Yes, if nodal pricing provides insufficient location signals (because then location-based grid charges are used to reinforce signals achieved through nodal pricing). No, in the sense that different pricing methodologies will apply to existing and new investments.	Yes, if nodal pricing provides insufficient location signals (because then funding is used to reinforce signals achieved through nodal pricing). No, because only some generation and load investments will be funded even though they all affect the need for grid investment.
<i>Promotes certainty</i>	Yes, because it extends postage stamp charging, which is well understood, to new investment.	Yes, once location charges bedded in. No, during implementation period.	Yes, once funding regime is determined. No, during implementation period.
<i>Difficult for parties to game the signal</i>	Yes generally, but large generators or load may be able to exploit gaming opportunities.	Yes generally, but large generators or load may be able to exploit gaming opportunities.	Yes generally, but large generators or load may be able to exploit gaming opportunities.
<i>Provides accurate signal</i>	Yes, if believe main factor undermining nodal pricing was the lack of transparent and robust processes for determining grid investment. No, if believe other factors undermine efficacy of	Depends on type of location charge regime and on how well location charges fill any gap left under option 1. Only LRMC charge provides accurate signal.	Depends on magnitude of errors incurred with conducting the GIT.

Table 2: Practical considerations (as required by rule 3.1)			
	nodal pricing.		
<i>Provides predictable/stable signals</i>	Yes, if congestion rentals are not used to part fund postage stamp charges. No, if use congestion rentals to part fund Transpower's revenue requirements.	Depends on type of location charge regime implemented. Causer pays approach should provide reasonably stable signals LPMC approach provides unstable signals.	Same as option 1
<i>Provides effective signal</i>	Yes, if believe nodal prices provide sufficient location signal. No otherwise.	Yes, provided complexity of location charges does not make them susceptible to lobbying to tinker with the methodology	Yes, if funding accurately fills the gap left by nodal prices. No, if believe nodal prices provide sufficient location signals or believe funding likely to be poorly targeted.
<i>Provides signal to small and large participants</i>	Yes.	Can be designed to provide same signal to all sizes of participants.	Depends on whether an effective mechanism can be developed to facilitate access and funding for small scale entities.

9. Other Pricing Methodology Issues

a) The connection charge

185. Existing connection assets are sunk, and therefore static efficiency will be enhanced if connection charges are set so that they do not reduce usage of these assets. The Commission's view is that charges for existing connection assets should be fixed at no more than the willingness of customers to pay for the service.
186. The current approach recovers the cost of deep connection assets from those connected to them. Where there is more than one party connected at a single point then the costs are allocated among them on a peak demand or injection basis. The Commission considers this may reasonably reflect the price that grid users would be willing to pay for connection to the core grid and should not distort grid usage.
187. Significant year-on-year changes in connection charges will create an uncertain environment, and the Commission's view is that this should be avoided if possible.
188. The Commission believes the definition of connection assets should be reviewed to ensure the definition is as deep as practicable, and consistent with other elements of the transmission pricing methodology. The Commission also believes it is important the definition of connection assets is applied consistently across the grid.

Q17: Do you agree connection charges should be set to achieve static efficiency? If not, what other approach should the Commission consider?

Q18: Do you agree the definition of connection assets should be as deep as practicable?

b) The HVDC charge

189. The HVDC charge on South Island generators was imposed on the basis that they were beneficiaries of the link, were unable to avoid the charge, and were unlikely to be able to pass it on to customers through energy prices. This latter feature meant the charge would be statically efficient. In addition, since at the time the construction of additional generation in the South Island looked unlikely, it was considered that the method of charging would not interfere with investment decisions, and so was also likely to be dynamically efficient.
190. A further factor behind the current charging regime when it was adopted was that by not combining the HVDC charge with the HVAC charge into the interconnection charge, the likelihood of uneconomic by-pass of the grid to avoid interconnection charges would be lower, and this would also improve dynamic efficiency.
191. As recommended by Frontier Economics, the Commission is proposing for consultation that revenue for all core grid assets should in principle be raised through a single interconnection charge, without a separate charge for the HVDC link. The Commission accepts there may be significant transition issues, and agrees separate charges for existing HVDC assets should be gradually phased out.
192. The Commission is also of the view that the costs of any upgrade of the HVDC link should be recovered in the same way as new HVAC core grid investments.

Q19: Do you agree that the costs of any upgrade of the HVDC link should be recovered in the same way as new HVAC core grid investments, and if not, why not?

c) The base for the interconnection charge

193. The Commission considers that imposing charges to recover core network costs on generators may distort generator bidding and dispatch, and investment in generation. Since such charges will ultimately be passed through to consumers any way, the Commission considers that the interconnection charges should be levied on offtake customers as they are under Transpower's present pricing methodology.
194. The interconnection charge is currently imposed on the basis of peak demand at individual grid exit points (GXP). The Commission considers this approach to be appropriate, but also believes it may be worth considering greater aggregation in GXP loads to encourage peak load management across regions.

Q20: What should be the basis for interconnection charges?

d) The economic value adjustment charge

195. The Commission acknowledges that the economic value adjustment charge has been set to zero for 2004/05. The Commission does not believe this charge needs to be part of the pricing methodology for Transpower.

Q21: Do you agree it is no longer necessary for the pricing methodology to include an economic value adjustment charge?

e) The prudent discount regime

196. The Commission considers that a prudent discount regime should be in place to ensure that inefficient bypass of the existing grid does not occur. Currently Transpower has considerable discretion to adjust their charges to a particular user where there is a realistic risk that the user may bypass the grid. Frontier proposes Transpower be required to formalise its approach to granting prudent discounts.³⁸

Q22: Do you agree that a prudent discount regime should continue to be available to Transpower, and if so, what constraints, if any, should be adopted to ensure Transpower exercises its discretion wisely?

f) Interim part F expenditure

197. The approved costs incurred by Transpower in relation to an interim grid expenditure approved under Rule 16 of Section III of Part F of the Rules will be recoverable by Transpower on the basis of the pricing methodology approved by the Commission.

g) Rental rebates

198. Part F requires the Commission to implement an FTR market, at which point it will decide how surplus loss and constraint rentals and the proceeds of FTR auctions

³⁸ Page 55, section 7.1.3 of the Frontier report.

should be allocated. In the interim the Commission believes Transpower should continue with its current approach to allocating loss and constraint rentals.

Q23: Do you agree Transpower should, in the interim, continue with its current approach to allocating loss and constraint rentals?

Appendix 1: The Economics of Location Signals and Nodal Pricing

199. Appendix 1 discusses the circumstances in which nodal pricing provides efficient incentives for investment in the grid, and for providing efficient location signals. Section 4 of the paper discusses the rationale for transmission charges, and the circumstances in which nodal pricing may fail to provide effective and efficient location signals.

Difficulties defining physical capacity rights

200. Like other transport services, transmission conveys energy from locations where it can be produced relatively cheaply to locations where it is valued highly by consumers. But 'loop flow' effects on the core grid make it fundamentally different from many other transport services. In effect, the core grid is a shared asset because it is difficult to define (and sell) physical capacity rights to circuits on the grid.
201. With 'loop flow' effects it is not possible to identify particular generators supplying particular offtakes – in physical terms, generators supply electricity to a pool and offtake parties withdraw electricity from that pool. This makes it impossible to attribute transport costs to consumers or generators on the basis of bilateral contracts agreed between them.
202. Likewise, it is not possible to quarantine to individual customers the expansion in *grid services* that arises from grid expansion. All customers downstream of a grid expansion receive the expanded service, in the form of reduced losses, reduced frequency and duration of binding constraints, and reduced probability of supply interruption. Moreover, the extent of the additional service varies by node, making it difficult to define and sell physical capacity rights for the grid.

Contract carriage versus common carriage

203. Contract carriage occurs when parties contract for conveyance of their goods, in effect booking or reserving physical capacity. For example, potato farmers book capacity on trucks, trains, airlines, and ships to transport their crop to market. The transport firm prevents other farmers loading their goods onto their trucks, to avoid congestion for existing users.
204. The difficulties with defining physical capacity rights makes contract carriage very difficult to achieve in transmission.³⁹ The current approach is known as common carriage, which is where the grid owner does not distinguish whose goods are being conveyed and does not reserve any portion of transmission capacity for any individual grid user.

Market pricing under contract carriage

205. Under contract carriage, goods are sold by independent auction at each location.⁴⁰ Each auction derives its own price, without any physical coordination between them.
206. Nevertheless, prices across locations are strongly interrelated. For example, suppose potatoes from Richmond (at the top of the South Island) are the

³⁹ Several jurisdictions in the United States are investigating the development of 'flow gate' rights, which attempt to overcome the problem by defining physical rights across multiple paths, but this concept is still in its infancy.

⁴⁰ The sales method need not be an auction, but it is useful to couch the discussion in these terms.

marginal source of potatoes to Auckland. The opportunity for traders to make arbitrage profits ensures the price of potatoes in Auckland equals the price of potatoes in Richmond plus the cost of transport between Richmond and Auckland.

207. If transport capacity out of Richmond is restricted for some reason, perhaps due to a strike, then potato prices in Auckland rise above the cost of transport from Richmond. In this case potato prices in Auckland would rise to the level required by local suppliers, such as those from Pukekohe.

Nodal pricing under common carriage

208. In contrast, under the common carriage regime, prices at each location/node are derived in a coordinated manner by the scheduling, pricing, and dispatch (SPD) model.⁴¹ The model contains estimates of the variable cost of transport (i.e., electrical losses), and is programmed to dispatch generation throughout New Zealand in ways that minimise the total cost of energy and reserves. SPD also provides for situations where transmission is congested or interrupted.⁴²
209. In effect, nodal pricing solves the problem of the lack of long-term physical capacity rights by auctioning generator access to the grid on a half-hourly basis.⁴³ SPD conducts coordinated auctions across all nodes, such that nodal price separation reflects the short run marginal cost of transmission when the grid is unconstrained, and the cost of local sources of energy when grid constraints are binding.
210. This is analogous to outcomes under contract carriage, where price separation is achieved via the decentralised actions of traders. With nodal pricing, price separation is achieved centrally via SPD.

Peak and off-peak pricing

211. A standard result in economics is that it is efficient to charge different prices for a good produced with a common facility, depending on whether the facility is operating below capacity or at capacity:
- a. When the facility is operating below capacity, the efficient (off-peak) price is one that equals the short run marginal cost (SRMC) of operating the facility; and
 - b. When demand exceeds capacity, the efficient (peak) price is one that reduces demand to the level where it equals available transmission capacity.
212. In the absence of large economies of scale, the peak price in (b) yields profits sufficient to pay for the capital costs of the facility. Moreover, the peak price equals the long run marginal cost (LRMC) of capacity expansion.
213. With regard to the grid, the efficient peak price at any node is that which rations *net demand* for electricity at that node to the level where it equals grid capacity to that node.⁴⁴ The SPD model achieves this outcome because it dispatches generation in a constrained region up to the point where local supply equals demand that cannot be met from the grid.

⁴¹ The model is called the scheduling, pricing, and dispatch (SPD) model, which is a linear programming representation of the core grid.

⁴² In this case the grid is said to be 'islanded', and the national market for energy splits into two or more regional markets. In these cases the model dispatches generation to minimise the total cost of energy and reserves for each island.

⁴³ Note dispatch rights are always subordinate to the right of the system operator to alter their dispatch instructions.

⁴⁴ Net demand is total demand minus local generation.

Merchant transmission investment

214. In the absence of significant economies of scale, nodal pricing would provide appropriate incentives for grid expansion and it would be unnecessary to regulate transmission providers. Also, loss and constraint rentals would provide adequate revenue to fund grid investment.
215. To see this, consider the case of a merchant grid provider that buys electricity at injection points at price P_b and sells it at offtake points at price P_s . In the absence of economies of scale, the merchant grid provider has incentives to:
- Expand circuit capacity if a 1-megawatt increase in capacity yields more revenue than the LRMC of circuit expansion. This will be the case where $P_s - P_b > \text{LRMC}$; and
 - Reduce circuit capacity if a 1-megawatt reduction in capacity yields cost savings greater than forgone revenue. This will be the case where $\text{LRMC} > P_s - P_b$.
216. The results in (a) and (b) show that, in the absence of large economies of scale, profit-maximising behaviour by merchant grid investors results in $P_s - P_b = \text{LRMC}$. This means that loss and constraint rentals will be sufficient to fund merchant transmission investment, and there is no need to charge transmission fees.
217. This is the same outcome that would be achieved under a contract carriage regime. In competitive transport markets, transport firms charge cartage fees equal to their LRMC of capacity expansion.⁴⁵ In markets with contract carriage, arbitrage ensures $P_s = P_b + \text{LRMC}$, whereas SPD achieves $P_s - P_b = \text{LRMC}$. The two results are equivalent.

Location signals

218. In a competitive goods market with contract carriage, consumers shopping at a location pay the same price for their goods regardless of where producers are located.⁴⁶ This gives producers appropriate incentives to locate near their market, as they trade-off the transport costs of delivering goods to market against the benefits of alternative locations (e.g. cheap access to land and raw materials, access to better quality labour, access to lower energy prices).
219. A similar outcome occurs under common carriage when nodal pricing is used. In this case generators face appropriate incentives to locate near load experiencing grid congestion. For example, nodal pricing encourages generators to locate gas-fired plants near Auckland. They will do so if higher nodal prices in Auckland (relative to Taranaki, for example) justify the additional cost of locating in Auckland, such as the cost of transporting gas over the Maui pipeline.
220. Consumers also face appropriate location incentives. In a competitive market the price of potatoes in Auckland exceeds the price of potatoes in Richmond by an amount equal to the cost of transport. Consumers face appropriate incentives to locate near producers, as they trade-off the higher cost of goods in Auckland against the benefits of Auckland over other locations (e.g. proximity to higher

⁴⁵ This must occur otherwise transport operators incur losses and exit the business. To earn their hurdle rate of return over the long run, transport firms must charge average cartage fees equal to their long run average cost (LRAC) of operation. In competitive markets $\text{LRMC} = \text{LRAC}$, and so average cartage fees equal LRMC.

⁴⁶ For example, a consumer of potatoes in Auckland pays the same price for the same variety and quality of potato regardless of whether the potatoes come from a farm in Pukekohe (near Auckland) or a farm in Richmond (top of the South Island).

paid employment or proximity to higher valued amenities).⁴⁷ Consumers face exactly the same trade-offs with nodal pricing of electricity.

The role of financial transmission rights (FTRs)

221. Although nodal pricing solves the problem of lack of physical capacity rights, it does so on a very short-term basis. Financial transmission rights (FTRs) provide holders of FTRs the right to receive half-hourly congestion rentals that arise from nodal price separation. In essence, FTRs provide longer-term signals of future nodal price differences.
222. For example, a monthly FTR contract for 10 megawatts for December 2004 for the Haywards to Bunnythorpe nodes gives the FTR holder the right to receive congestion rentals associated with half-hourly nodal price separation between Haywards and Bunnythorpe on 10 MW for the month of December. FTRs would likely be traded on a secondary market, at prices that reflect buyers and sellers views of the average price separation between Haywards and Bunnythorpe during the month of December 2004.

Implications for transmission investment and pricing

223. Without large economies of scale, nodal prices provide efficient signals for grid investment, and competition among merchant transmission operators would protect generators and load from grid operators restricting capacity to earn monopoly profits. FTRs, and other types of transmission hedges, could be used to provide longer-term signals of nodal price differences.
224. More importantly for this paper, in the absence of large economies of scale *there is no need to charge transmission fees* because loss and constraint rentals would be sufficient to fund grid investment.

⁴⁷ This is deliberately a very simplified example. Obviously consumers buy a wide variety of goods and services, and generally will not make location decisions based on the relative prices of a single commodity.

Appendix 2: Experience With ‘Power Flow’ Based Location Transmission Charges

Introduction

225. This section discusses issues arising from ‘power flow’ based location charges. The usual intention with power flow modelling is to identify users of the transmission system, and allocate transmission sunk costs and new investments specifically to users.⁴⁸ This is similar to the ‘transport methodology’ employed by Transpower from October 1996 to March 1999, which allocated 50% of ‘use of system’ charges based on power flow analysis.

Economic efficiency

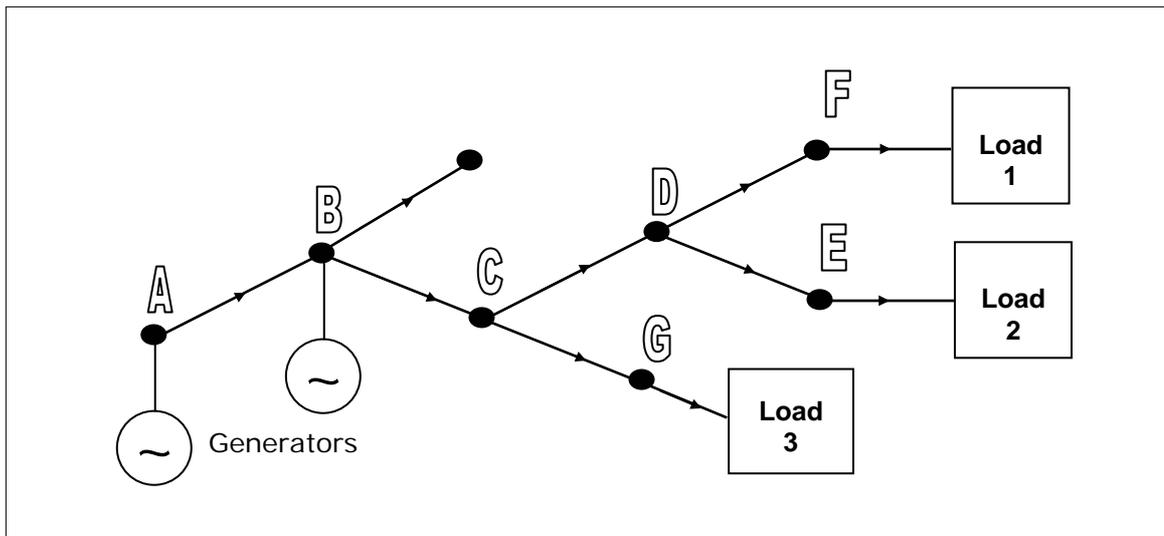
226. The power flow approach ensures no party is charged grid fees above their stand-alone cost, or below their incremental cost, which ensures cross subsidies are largely precluded. This is achieved because power flow analysis typically proxies ‘user pays’, and user pays is generally a good means to ensure costs allocated are below the stand alone costs and above the incremental cost of a service.

Stylised example

227. In Figure 5 below, a simplistic power flow analysis is used to demonstrate how costs could be allocated under this approach. The results are tabulated below.

	Uniquely (100%) allocated circuits	Shared Circuits (based on percentage of usage as modelled)
Load 1	Circuit D-F only	Circuits A-B, B-C, and C-D.
Load 2	Circuit D-E only	Circuits A-B, B-C, and C-D.
Load 3	Circuit C-G only	Circuits A-B, and B-C.

Figure 5 – Schematic of power flows.



⁴⁸ Power flow modelling typically involves analysing static ‘snapshots’ of the electrical power system (e.g. a single trading period), such that the use of each transmission circuit can be attributed to each relevant GXP.

228. In the example in Diagram 1, shared circuits are allocated to parties in proportion to their use of those circuits. Thus, the power flow analysis aims to identify which assets are used, and how much they are used, by each relevant GXP.
229. Power flow approaches typically model historical behaviour, as forecasting generator behaviour is much more difficult and often highly contentious. While this does make it easier, there are still significant difficulties with the power flow modelling approach. In particular, there are two key issues that are explored in detail below:
- a. Measuring historical usage of the system; and
 - b. Year-to-year variability (null points, and generation assumptions).

Measuring historical usage of the system

230. The power flow approach uses static power flow analysis, which looks at snapshots of grid usage at points in time (say, on a trading period basis). Clearly, static power flow analysis can only approximate a highly dynamic system, and will be inaccurate. Greater accuracy can be obtained by examining a greater number of trading periods, but this increases the computational complexity of the analysis.
231. There are 17,520 trading periods in a year, and the combination of generation and demand scenarios can vary significantly from day to day.⁴⁹ There are two main ways to try to capture this variation in power flow:
- a. Use all 17,520 periods from a year to derive scenarios for average generation and average demand; or
 - b. Select and analyse a number of actual trading periods deemed representative of transmission usage.⁵⁰

The average approach

232. The average approach is reasonably simple and accurate for measuring grid usage by load parties, because load is highly predictable and cyclical, and so only a small number of load patterns require modelling.
233. This is not the case for generation, which is highly variable and unpredictable. Under the average approach, generation patterns can be created that often don't occur in reality. For example, some base load generation either operates near maximum output (e.g. at 80% load factor) or not at all. The average approach would model them at their average output throughout the year (e.g. 40% load factor for the year), which is erroneous. Likewise, modelling wind power as a steady 50% capacity factor output creates inaccuracies.

The representative approach

234. Generation is also difficult to model under the representative approach, because it is difficult to select representative generation scenarios. Under the representative approach only a small number of trading periods are modelled, and so the results are sensitive to the choice of generation scenarios. This is more of a problem in

⁴⁹ As noted, there are 17,520 trading periods in a year; analysing even 1% of these with detailed power flow analysis is an enormous task. Typically, several years of data may need to be analysed to mitigate aberrations such as dry years etc.

⁵⁰ Transpower's 'transport methodology' used a combination of these approaches where by the annual average generator output was used, though the load scenarios were the top 25% national demand scenarios (the generation results were scaled to meet load).

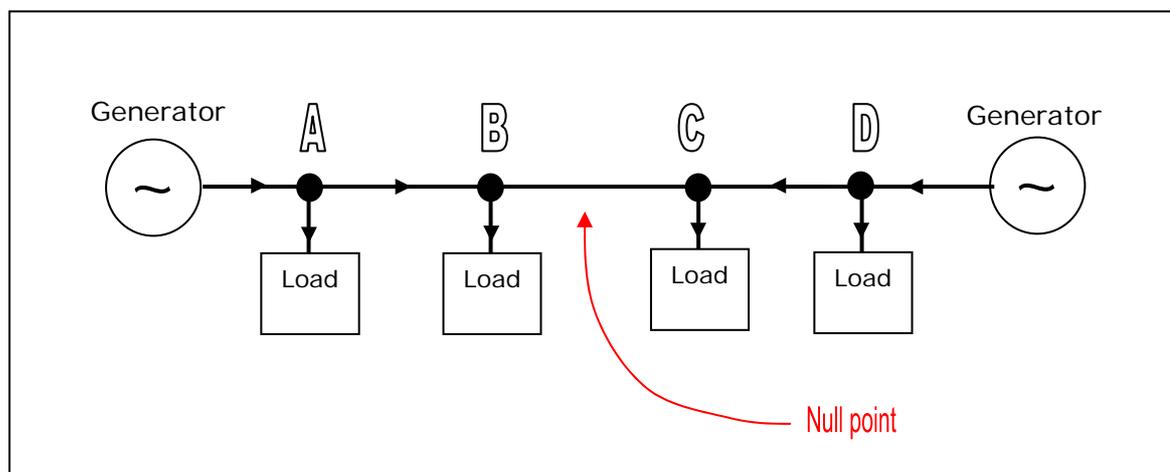
New Zealand compared to overseas jurisdictions given New Zealand's variable generation patterns, and 'long stringy' transmission system.

235. The representative approach also introduces a high degree of subjectivity into the modelling. This is highly undesirable as the assumptions of what is, and what is not, representative carry significant value implications for grid users and become highly contentious.

Year-to-year variability

236. Anecdotally, a key problem with Transpower's 'transport' methodology was significant year-to-year changes in transmission charges for some customers. This variability was inherent in the methodology, and not reflective of any changes in transmission costs. A key source of the variability is known as the 'null point' issue,⁵¹
237. The New Zealand power system has transmission circuits in parallel, and also generators located throughout the country. When modelling such a system using average power flows, there are points on the transmission grid where circuits are very lightly loaded. In the extreme there will be places in the model that show zero power flow, where equal amounts of power come from two different directions.
238. The 'null point' problem is illustrated in Figure 6, where there is a 'null point' somewhere between nodes B and C because there is no power flow in either direction.

Figure 6 – Schematic of null point issue



239. As noted above, the output of generators in reality is highly variable, and the modelling of generation in power flow analysis is subjective to some degree. A small change in assumed generator output could easily move the null point from between B and C, to either between A and B, or between C and D (or even further). When the null point moves, the allocation of transmission circuits also changes significantly for customers in the vicinity of the change.

⁵¹ Other drivers for variability are simpler to understand, and thus not explored in detail (e.g. new entrant generators changing power flows without affecting transmission costs, changes in generation modelling assumptions, and dry year outcomes affecting generation scenarios, etc).

Appendix 3: LRMC Based Location Charges

240. This appendix discusses the long-run marginal cost (LRMC) approach to location charges. This approach sets charges at each GXP to reflect the LRMC of transmission capacity for that specific GXP.
241. The LRMC approach provides a forward-looking price signal. This is achieved by imposing charges on load near circuits that require capacity expansion, at rates that reflect the LRMC of imminent investments. Consumers located near circuits with spare capacity face lower charges.

Complexity

242. LRMC based transmission pricing is very complex to implement. It is predicated upon having a robust and reliable forecast of demand and generation at a GXP level (i.e. not national, nor regional, but at each individual node). This forecast must be for a significant term, due to the significantly long life of transmission assets (along with other related industry investments), which are of the order of 20-40 years.
243. Transmission line flows are significantly dependent upon generation patterns, and thus forecasting generation investment over the necessary terms in a robust manner is a considerable challenge. While this is similar to the analysis required for the GIT, it is required annually, and across the entire grid, not just where investment is imminent. This is the primary complexity of the LRMC approach, and this may, at least for some regions, significantly limit the efficacy of the LRMC signals where forecasts are materially in error.

Variability of revenue

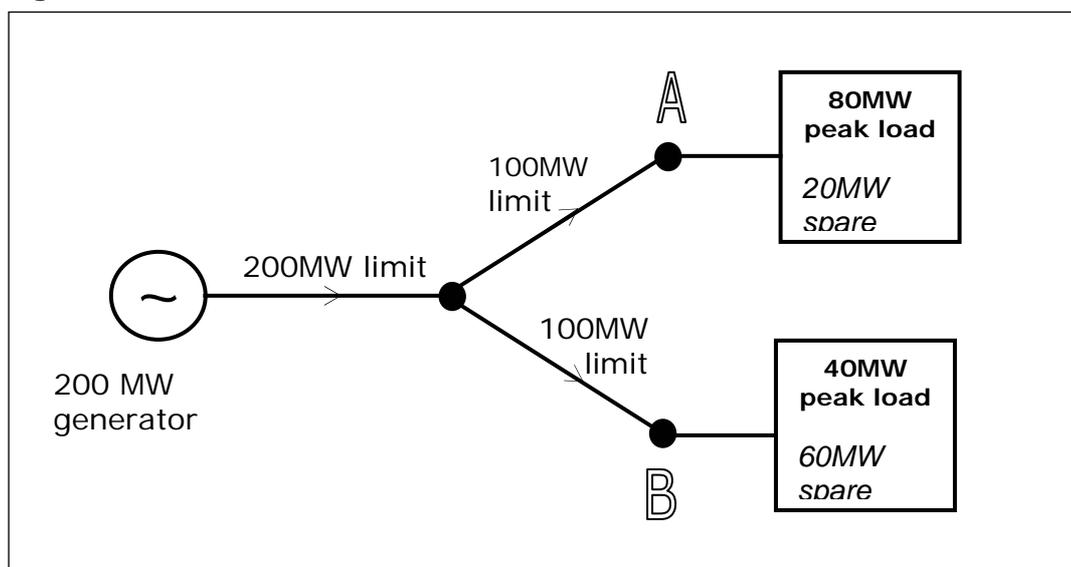
244. Given that LRMC charges signal impending grid investment, the total LRMC charge would vary with time depending on the average asset age, and load growth. For example, consider the situation just after major grid investment when significant costs have been incurred by Transpower. The LRMC at most, if not all, GXPs will be comparatively low, thus the overall transmission revenue would be low.
245. The variability of revenue has significant implications for Transpower who have a fixed revenue to recover in any one year. The likely consequence would be that the LRMC charges would be scaled to the level of Transpower's revenue requirement. In doing so, the efficacy of the signal would be lost, as it would no longer signal the actual LRMC at any particular node, rather just a higher or lower charge. Thus the efficient tradeoffs in location decisions would not be made as the magnitude of the signal would only be indicative at best.

Perverse location incentives for large load

246. It is not clear the LRMC approach achieves efficient location decisions for large load. Consider a hypothetical example with two GXPs (illustrated in Figure 7 below). GXP A has 20 MW of spare capacity at peak, and GXP B has 60 MW of free capacity at peak. These GXPs are identical except for their peak demand. The LRMC transmission charge at GXP A is higher than that of GXP B, as GXP B has more spare capacity.

247. Assume a new customer is considering whether to locate its new 40 MW load at GXP A or B.⁵² From an economic efficiency perspective, the customer should locate at GXP B as there is sufficient spare capacity at that GXP.
248. However, consider what happens if the new load located at GXP B. The new load would face very high transmission charges in ensuing years, as the new 40 MW load brings the GXP closer to constraint. This brings forward the necessary grid upgrade, which translates to a higher LRMC.
249. Now consider what happens if the new load located at GXP A. This would lead to an immediate grid upgrade, because additional capacity is required to accommodate the additional load. But once the upgrade occurs, the LRMC at GXP A drops significantly as spare capacity is now available (due to the lumpiness of transmission investment, the minimum capacity increment may be 100 MW). The rational choice for new load is to choose GXP A, which is an inefficient outcome.
250. Although the above was a contrived example, it serves to illustrate that large load may choose to locate at a GXP to inefficiently accelerate transmission investment at times simply to gain the benefits of a wealth transfer.

Figure 7 – LRMC investment scenario



Perverse incentives for alternatives

251. A further example of the complexity of LRMC charges arises when considering incentives for alternatives to transmission. Grid investments tend to be relatively large, and so relieve grid congestion for long periods of time. In contrast, alternatives to transmission are often quite small, and so relieve grid congestion for shorter periods of time. This means circuits operate closer to their rated capacity for prolonged periods of time, which leaves consumers at those GXPs incurring high transmission charges for prolonged periods of time.
252. As in the example above, offtake customers at those GXPs have incentives to discourage alternatives to transmission and accelerate the transmission investment, to reduce their LRMC charges. In addition, it is in the customers

⁵² It is assumed here that we are most interested in signalling to large load.

interests to lobby for transmission solutions that have significant spare capacity, which could lead to 'over building' if lobbying was successful.

Appendix 4: Location Charges Using the Indicative Model Approach

253. This appendix illustrates how location charges might work in practice for the indicative model presented in section 6 of this paper. All numbers used to illustrate the model are hypothetical.

Step 1: identification of beneficiaries

254. The illustrative example is a proposal by Transpower to invest \$5 million to upgrade a line to increase its thermal capacity. The first step is to identify GXPs that will benefit from the upgrade, by analysing the direction of flows on circuits over the past two years. Circuits with load flows in one direction 70% or more of the time are labelled with an arrow in the direction of the flow. Circuits with load flows in one direction between 50% and 70% are left blank.

255. Beneficiary GXPs are found by moving downstream from the investment in question until a circuit with an opposing power flow arrow is met. All GXPs that are passed through before the opposing load flow is reached are the beneficiaries of the investment.

256. We will assume that applying this method to the proposed investment in the upgrade results in the GXPs listed in Table 3 (below) being identified as the beneficiaries of Transpower's investment.

Step 2: determination of flows at peak times

257. The second step is to identify the top 10% of half-hour trading period demands on the asset being upgraded over each of the current and preceding five years, and then to record the flows at the beneficiary GXPs (and to various parties connected to each GXP) in these top 10% peak flow periods in each of these six years.

258. The data contained in the first six columns of Table 3 are these historical peak flow coincident data. The data are hypothetical. For illustrative purpose we assume that there are two parties connected at GXP D, a direct connect customers (D – Direct) whose offtake at peak times has been falling due to energy conservation measures it has been taking, and a distributor (D - Distributor), whose offtake at peak times has been rising.

Step 3: allocation of upgrade costs to customers

259. The final step is to allocate the investment upgrade costs among the various parties connected at the beneficiary GXPs. In Table 3 this is done on the basis of the proportion of the increase between the average peak time load in the last three years and the three years prior to that attributable to each connected customer at a beneficiary GXP. The calculations in the final six columns of Table 3 achieve this.

260. Customers that have held or reduced their demand between these periods, like those at D – Direct and G, do not contribute to the investment to deal with the increased load. Those, that have been significant contributors to the increased load, like the customers at A, B and H, bear a proportionately high share of the cost of the investment in the asset.

261. The allocation of costs among customers at beneficiary GXPs could be done on other bases, such as the change in load between the current year and five years

ago, but if load growth at the various GXPs over the five years is relatively constant then this will have little or no impact on the proportionate shares of investment costs assigned to each GXP.

262. In the example, since the total expenditure is \$5m, if the WACC Transpower seeks is 7% post-tax (10.45% pre-tax) and the assumed life of the capacitors is 20 years, then the total annual charge to cover the cost of the capacitor upgrades will start out at \$772,500. This means that the charge at D - Distributor under the hypothetical numbers would be \$31,634 and at H it would be \$213,915.

Table 3: Illustration of location charges under the indicative model

	T-0	T-1	T-2	T-3	T-4	T-5	Avg T-0 to T-2	Avg T-3 to T-5	Change	% Change	Increases	Allocation Under Locational Pricing %	Allocation Under Causer Pays \$
A	30.00	29.55	29.11	28.67	28.24	27.82	29.55	28.24	1.31	4.64%	1.31	18.61%	\$143,791
B	28.00	27.58	27.17	26.76	26.36	25.96	27.58	26.36	1.22	4.64%	1.22	17.37%	\$134,205
C	17.00	16.66	16.33	16.00	15.68	15.37	16.66	15.68	0.98	6.25%	0.98	13.92%	\$107,555
D - Direct	10.00	10.30	10.61	10.93	11.26	11.59	10.30	11.26	-0.96	-8.49%	0.00	0.00%	\$0
D - Distributor	5.00	4.90	4.80	4.71	4.61	4.52	4.90	4.61	0.29	6.25%	0.29	4.09%	\$31,634
E	4.00	3.88	3.76	3.65	3.54	3.43	3.88	3.54	0.34	9.57%	0.34	4.82%	\$37,203
F	7.00	6.65	6.32	6.00	5.70	5.42	6.66	5.71	0.95	16.64%	0.95	13.49%	\$104,198
G	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	0.00	0.00%	0.00	0.00%	\$0
H	23.00	22.31	21.64	20.99	20.36	19.75	22.32	20.37	1.95	9.57%	1.95	27.69%	\$213,915
Total											7.04	100.00%	\$772,500

Appendix 5: Materiality & Stress Testing Of Location Transmission Pricing

Introduction

263. Location transmission prices aim to send a signal to locate new load (and potentially generation) where it is most efficient from the electricity sector point of view in isolation.
264. It is worthwhile considering the magnitude of location transmission price signals in the context of other location signals, particularly for large load. This is a guide to the materiality of the signal, which should be kept in mind when considering the accuracy and complexity of implementing the location transmission price signals.
265. Large loads can be characterised into two generic types to illustrate the materiality of location transmission price signals; namely medium scale industrials, and large energy intensive loads.

Medium scale industries

266. According to the report by the Centre for Advanced Engineering, approximately 86% of commercial and industrial firms have electricity related costs of the order of 1%- 5% of their overall costs.⁵³ Table 4 shows that the location component of grid charges may account for only a very small proportion of total costs for typical commercial users. The impact on most major energy users is larger, but still small, at 1.5%.

Table 4: Materiality of grid charges

Cost component	Percentage of total costs	
	Commercial Load ⁵⁴	Major Users ⁵⁵
Delivered electricity charges as a percent of total costs	<5%	<15%
Grid charges as a percent of total costs (assuming transmission accounts for 20% of delivered electricity charges)	<1%	<3%
Location charges as a percent of total costs (assuming location charges are 50% of total transmission charges if interconnection revenue was used fully)	<0.5%	<1.5%

Large intensive electricity users

267. The impact of location charges on very large energy intensive loads is unclear as their location decisions will often be driven by factors other than transmission. The larger a plant becomes, the typically more reliant it is on transport infrastructure for raw materials (shipping or rail), workforce, and ability to gain environmental consents. In addition, by virtue of assuming a large energy intensive load, the proportion of the transmission costs to energy costs will be

⁵³ CAE Project Report, "Reliability of Electricity Supply," 1993, page 31.

⁵⁴ These figures apply to 86% of commercial and industrial firms.

⁵⁵ These figures apply to 70% of major electricity users.

even lower than for other types of plant; thus of the electricity costs the energy component will dominate.

268. Furthermore, if it is the case that a large load required grid upgrades wherever they locate (due to size), there may only be a very minor economic benefit in one location to another from a transmission perspective. This suggests transmission location signals are of low materiality to the location decisions of large loads.

269. Consider the example of large new load (i.e. energy intensive) deciding where to locate plant in New Zealand. The table below summarises the expected outcomes in terms of signals and incentives under each option.

Table 5: Location signals and incentives for large load

Option	Location Signals	Efficient Incentives	Inefficient Incentives
1 - Adopt postage stamp UOS charges. No regulated funding of alternatives to transmission.	No signal from UOS charges. Location signals from nodal pricing and the GIT.	Large load has appropriate incentives to manage demand to minimise energy prices.	Gaming problems may undermine location signals for large load.
1a - Adopt postage stamp UOS charges, and regulated funding of alternatives to transmission.	No signal from UOS charges. Location signals from nodal pricing and the GIT.	Large load has appropriate incentives to manage demand to minimise energy prices. Regulated funding may provide large load with appropriate incentives to locate to avoid inefficient grid investment.	Regulated funding provides large load with incentives to falsely claim they will not locate in an area without funding.
2 – Adopt location-based UOS charges for new investment, and postage stamp charges for existing assets. No regulated funding of alternatives to transmission.	Location signal from UOS charges. Location signals from nodal pricing and the GIT.	Large load has appropriate incentives to manage demand to minimise energy prices. Location charges may provide large load with appropriate incentives to locate to avoid inefficient grid investment.	The effectiveness of location charges may be undermined by regulatory risks.

Appendix 6: Format for Submissions

Submission Summary Table – TITLE of PAPER

Paragraph	Comment	Proposed amendment
<i>Para 12</i>	<i>Paragraph 4 does not....</i>	<i>We think that instead you should take the following approach</i>