Summary of submissions received on consultation paper 'Options For Enabling Transmission Alternatives'

Call for cross submissions

December 2005

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1. Executive summary

1. The Electricity Commission's (**Commission**'s) 'Options for Enabling Transmission Alternatives' consultation paper of 31 May 2005 (**Consultation Paper**) received responses from 20 submitters. The Commission has decided to seek cross submissions from interested parties on the content of the original submissions.

2. The submitters included: five electricity generator-retailers, three electricity lines companies, two large electricity consumers, four member organisations, Transpower New Zealand Limited (**Transpower**), the Energy Efficiency and Conservation Authority (**EECA**), two other energy-related businesses, and two individuals.

3. The submissions received expressed the following preferences:

   a) Four primarily favoured option 1 (market response), with or without some modifications/market developments;

   b) Two primarily favoured option 2 (universal central procurement);

   c) Three primarily favoured option 3 (minimal central procurement);

   d) Two primarily favoured option 4 (limited decentralised procurement), one of these with modifications;

   e) None primarily favoured option 5 (regional capacity contracts mechanism); and

   f) The remainder of submitters did not state a preference for any of the options proposed.

4. In response to the Consultation Paper, submitters raised a number of issues regarding the problem definition, evaluation criteria, options, cost benefit analysis, and linkages with other work streams, as well as making some comments regarding the process that has been followed.

Problem definition and market design considerations

5. Regarding the problem definition, submitters' main issues related to the existence or otherwise of the free rider and commitment problems (and what submitters believed to be the underlying causes of these), whether the scale of the problem was sufficient to justify enabling arrangements, and the definition of Transmission Alternatives (**TA**s).

6. The Commission remains of the view that the free rider and commitment problems are significant barriers to investment in TAs, and that the scale of the issue is sufficient to continue working towards the removal of inefficient barriers. It accepts that some submitters have identified alternative responses to these problems, particularly involving enhanced market design (for example, capacity pricing), and notes that it will be proposing a work programme to consider market design issues including capacity market arrangements and decentralised procurement.

7. The Commission agrees that there are also strong linkages between existing work streams (such as locational pricing) and the TA work stream. It notes that it will continue to consider such linkages while undertaking this work.

Evaluation criteria

8. A number of submissions were made on the Commission's evaluation criteria. Following consideration of these, the Commission considers that the criteria are broadly appropriate, and has suggested only minor changes.

Dynamic efficiency concerns

9. Submitters were asked for their views regarding potential dynamic efficiency effects of TA procurement. Some responded that the risk was overstated, and others that the risk was sufficiently large as to prevent development of TA enabling arrangements. Following further deliberation, the Commission has concluded that dynamic efficiency risks are a key issue with the development of TAs, but it does not agree that the risks are so large that enablement of TAs should not be considered further. Dynamic efficiency risks will be considered further in developing the final decision paper and in any subsequent rule change development.

Cost-benefit assessment (CBA)

10. Several submitters raised concern that a quantitative CBA had not been undertaken prior to consultation. The Commission notes that it will complete a CBA following a decision on the high level approach to TAs and prior to any rule change. The rule change process requires the consideration and assessment of alternatives, so undertaking the CBA at this time does not presuppose selection of an option prior to undertaking the analysis.

Conclusions

11. The Commission concludes that there are significant barriers to the development of TAs under current regulatory arrangements, and that being able to effectively manage dynamic efficiency risks will be key to the development of any TA enablement mechanism.

12. In the long term, the development of market based measures such as capacity mechanisms and locational transmission pricing may be sufficient to address barriers to TAs. However, the Commission believes that it may be necessary to implement an interim solution to enable TAs.

13. If an interim solution is required, the Commission's preferred interim approach is some form of minimal central procurement (minimal CP). The Commission considers that minimal CP is preferable to universal central procurement, as minimal CP is targeted at the problems and has much lower dynamic efficiency risks. Minimal CP is preferable to current arrangements as it allows the procurement of cost effective TAs both to substitute for transmission investment and to manage risks around transmission upgrades.

14. The Commission proposes to further consider the need for enablement of transmission alternatives following cross submission and consultation on this Summary of Submissions document and following progress on the consideration of Transpower's initial Grid Upgrade Plan (**GUP**).

Questions for consultation

Q1.	Are there major arguments in any of the submissions that you disagree with? If so, can you please explain the reasons for your disagreement and a discussion of what your argument would imply for TAs?
Q2.	Do you agree with the Commission's response to the submissions? If not, please explain which section you disagree with and why.

2. Introduction

15. The Government Policy Statement on Electricity Governance (**GPS**) requires the Electricity Commission (**Commission**) to "consider whether there would be net benefits in providing for a mechanism whereby investments in transmission alternatives receive payments reflecting some or all of the value of avoided transmission investment" (paragraph 90).

16. The Commission's work stream on enabling Transmission Alternatives (**TA**s) specifically seeks to advance this policy requirement.

17. On 31 May 2005, the Commission published a consultation paper entitled 'Options for Enabling Transmission Alternatives'.

18. The purpose of the consultation paper was to assist with establishing the Commission's high-level policy direction regarding enabling TAs, by presenting analysis and seeking submissions on the options for facilitating TA investment.

3. Purpose

19. The purpose of this paper is to:

    a) provide a summary of the key issues raised by submitters;

    b) provide a proposed response on each issue; and

    c) seek cross submissions on the original submissions.

20. Following receipt of comments on this paper and cross submissions a final decision paper will be prepared.

3.1 Format for submissions

21. The Commission invites cross submissions on the original submissions and the summary contained in this paper including but not limited to answers to the specific questions contained in this paper by **5pm** on **Monday 20 February 2006**.

22. The Commission's preference is to receive submissions in electronic format (Microsoft Word and/or pdf). It is not necessary for parties submitting to send the Commission hard copies of their submissions, unless it is not possible to do so electronically. Electronic submissions should be emailed to info@electricitycommission.govt.nz with 'TAs further submission' in the subject header. Any hard copies of submissions should be posted to the address below.

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

24. Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, submitters should note that the Commission is subject to the Official Information Act 1982.

4. Submissions summary and discussion

25. This section of the paper provides a summary of the issues raised in the submissions. It draws conclusions on how each issue should be addressed and identifies further work that may be required. The broad headings are:

    a) Submissions regarding problem definition;

    b) Submissions regarding evaluation criteria;

    c) Dynamic efficiency issues;

    d) Submitters' evaluations of the options, including preferred option and other options proposed;

    e) Discussion regarding cost benefit analysis;

    f) Discussion regarding linkages with other work streams; and

    g) Submissions regarding process that has been followed.

26. The summary focuses on the key issues raised during consultation. Some of the questions that were asked during consultation are not summarised here, particularly those that focussed on the design and implementation details of a procurement regime. Generally, implementation issues will be considered in detail at the time of the development of any rule change. Although, it may be necessary in some cases to consider some implementation issues earlier, to the extent they impact upon the merits of the options.

4.1 Submissions regarding problem definition

4.1.1 The consultation paper

27. The Commission's problem definition can be summarised as follows:

    a) The Commission must use the Grid Investment Test (**GIT**) to determine whether to approve a Grid Upgrade Plan (**GUP**). This requires consideration of whether TAs are more efficient than grid investment.

    b) As substitutes for grid reliability investment, the Commission needs confidence that TAs will eventuate if it is to reject a grid reliability investment.

    c) Though some TAs have emerged historically, the Commission believes that free-rider[1] and commitment problems may have prevented many efficient TAs from being developed. It believes that the development of TAs is even less likely in future without procurement, particularly on the core grid.

28. Submitters were asked:

    a) whether they agreed with the problem definition; and

    b) whether they believed the optimal level of transmission and TA investment has occurred in the past.

4.1.2 Submissions

29. More than half of the submissions commented on the problem definition put forward by the Commission in the consultation paper. Of these, approximately 50% agreed or mostly agreed, and 50% disagreed with the problem definition.[2]

30. The remainder of this section of the paper discusses the main themes relating to problem definition in the submissions.

TAs as substitutes for grid investment

31. Several parties, including MRP/NERA, Meridian, and Orion noted that the wording in the consultation paper implies that TAs are direct substitutes for grid investment, but does not consider that TAs and grid investment could be complementary.

[1] Free riding on transmission charges for generators, and on both transmission charges and nodal prices for the demand side.

[2] Mighty River Power (**MRP**)/NERA, Genesis Energy (**Genesis**), Transpower New Zealand (**Transpower**), Meridian Energy (**Meridian**), and the Sustainable Energy Forum (**SEF**) disagreed with the problem definition. Contact Energy (**Contact**), Orion New Zealand (**Orion**), Solid Energy, Comalco, the Major Electricity Users' Group (**MEUG**)/New Zealand Institute of Economic Research (**NZIER**), and EECA agreed or mostly agreed with the problem definition. The Electricity Networks Association (**ENA**) and Trustpower agreed with some aspects of the problem definition.

32. Submitters noted that to be of value, TAs do not necessarily need to substitute for transmission, and this is unlikely to be where they are of most value. TAs can:

    a) provide significant deferral value, by enabling transmission investment to be delayed for some years. Particularly in the early years, this can have a significant value due to the 'lumpy' nature of grid upgrades;[3]

    b) be useful for managing uncertainty during transmission construction periods; and

    c) be useful for emergency risk management.

33. It was suggested that any arrangements for TAs should focus on developing an approach that encourages the most efficient solution, which may include a combination of grid investment, demand-side initiatives, and additional generation capacity.

Scale of the problem

34. Several submitters commented on the scale of the problem that the Commission is working to address.

35. Some submitters did not believe that the consultation paper adequately demonstrated that there is a problem that needs to be solved or that there are real barriers to investment in transmission alternatives. For instance, the paper does not provide any evidence that regulatory processes would have delivered different or lower cost outcomes, and it provides no examples of where TA investment would have been more efficient than grid investment. These submitters do not accept that free rider problems have led to fewer than optimal TAs emerging in the past, and they note there are many factors that impact on the commercial viability of TAs.

36. Meridian noted that the report it commissioned from Charles Rivers Associates (**CRA**)[4] suggests that potential generation and demand-side TAs are already commercially viable or nearly so. Regulatory processes to enable TAs would not therefore be expected to deliver a different result to that produced under normal commercial decision-making processes.

37. Several submitters provided further examples of TAs that have occurred but were not listed in the paper.[5]

38. Several submitters held the opposing view, suggesting that there has not been an optimal level of investment in TAs in the past. One submitter suggested investment in TAs that has occurred was driven by benefits other than transmission cost avoidance, rather by arbitrary transmission pricing

[3] Note the Commission views TAs as substitutes for grid investment, rather than complements, if they defer grid investment.
[4] Appended to its submission.
[5] See Mighty River Power's submission, specifically. Examples cited include a runback scheme at Te Awamutu (paid for by Genesis Energy to avoid paying for grid upgrades between HAM and KPO), Marsden A voltage support, and the Tauranga demand inter-trip scheme (funded by Trustpower and Unison).

methodologies. It noted that investment in alternatives in response to a pricing signal has been limited to local generation and ripple control schemes, both of which receive benefits through avoided transmission payments.

Validity of free rider issues

39. Approximately half of the submitters that commented on free rider issues[6] agreed that it is a valid problem, while the other half did not agree.

40. MRP/NERA considered that free-rider problems are not market failures but problems arising from the Commission's approach to the GIT and transmission pricing. They note that a number of TAs have been developed despite free rider issues.

41. Transpower considered there has not been a market failure in terms of generation locational investment decisions, though there has been in terms of transmission investment.

Free rider: transmission charges

42. A number of submitters disagreed with the assessment of free rider problems in regard to transmission charges:

    a) Meridian and MRP noted that transmission charges are only one of many factors considered in making investment decisions, and are unlikely to be sufficient to merit the proposed intervention; and

    b) Genesis noted that it does not consider there to be a significant transmission pricing free rider problem for energy market investments, though there may be for a narrower subset of TAs that provide solely transmission services.

43. The opposing view, and the premise of the free rider problem, is that free rider problems have undermined incentives to invest in TAs. Several submitters noted that the use of locational transmission pricing would mitigate any free rider problem. This issue is discussed later in the paper.

44. Contact noted that some free rider issues arise as a result of grid owner inability to selectively disconnect customers at times of shortage.

Free rider: nodal pricing

45. The same submitters that disagreed with the assessment of transmission charging free rider problems also disagreed with the assessment of nodal pricing free rider problems, arguing that it is not a significant problem (particularly for generators). Meridian suggested that the change to the level

[6] Paragraph 11 (a) of the consultation paper describes free rider problems as follows: "All consumers in a region benefit from the actions of other consumers or local generators who reduce demand for transmission and thereby reduce nodal prices and transmission charges for all consumers." The paper goes on to say that "In theory, the free rider problem should not constrain investment by generators as they are able to capture benefits from rising nodal prices at times of transmission constraint. However, under a postage stamp transmission charging methodology, generators are unable to capture the full avoided cost of transmission from their investment in TAs."

of nodal prices following an investment are not generally substantial and the effect is outweighed by additional revenue received at the average national price.

46. Other submitters agreed that there is a nodal pricing free rider problem, though some believed it was only a problem for the demand side. However, these same submitters did not necessarily agree with the Commission's assessment that the free rider problem can be managed by generators through amending their offers:

    a) One submitter suggested that this does not work because most new generation is "must run";

    b) Contact suggested that there are some informational and political impediments that prevent generators developing offer strategies which address the nodal pricing free rider problem; and

    c) Orion suggested that the idea that generators can adopt offer strategies to deal with the free rider problem indicates a degree of market power that is undesirable.

Validity of commitment issue

47. As with the free rider problem, several submitters suggested that the "commitment problem"[7] is not a market failure but a problem arising from the Commission's approach to the GIT and transmission pricing:

    a) Genesis suggested that the commitment problem is incorrectly stated, noting that "proper" application of the GIT and GUP processes will provide investors sufficient certainty to proceed with economically efficient investments without risk of subsequent stranding by a regulated transmission investment; and

    b) Transpower noted that it does not disagree with the stated commitment problem, but considers that putting in place arrangements to procure TAs would adversely affect the situation by delaying TA contracting until after the GIT process is complete. It proposed that this could be addressed by requiring the Grid Owner to include consideration of TAs within its GUP, including (if necessary) contracting with TAs to provide services.

48. One submitter suggested that it is incorrect to state that transmission can strand generation investments.

49. Genesis suggested that the commitment problem for generation investments is more to do with other uncertainties, such as resource consents, land, and fuel supply uncertainty, than it is funding issues. ENA suggested that it is caused by institutional barriers such as grid pricing and the Electricity Industry Reform Act 1998 (EIRA).

[7] Paragraph 11 (b) of the consultation paper describes the commitment problem as follows: TA providers, particularly generators, are less likely to commit to large sunk investments if Transpower can strand their investment by subsequently undertaking its own investments and recovering costs through regulated means." The consultation paper does not refer to the commitment problem as a market failure.

Validity of regulatory certainty issue

50. Question 7 in the consultation paper asked whether submitters agree with the Commission's assessment of the regulatory certainty issue[8].

51. MRP and Transpower did not agree with the Commission's assessment of the regulatory certainty issue. Transpower argued that it is the market and not the Commission that requires certainty. This certainty is best achieved by not interfering through regulated procurement of TAs. MRP noted the comment in the consultation paper, that the repeated nature of grid investment decisions will enable the EC to reduce or eliminate commitment problems over time. MRP also noted that there will be a trade-off between static efficiency gains and the dynamic efficiency losses from regulated procurement and that the Commission should give greater weight to dynamic efficiency.

52. Trustpower believed that regulatory certainty concerns may be overstated, though it suggested that there may need to be more certainty around regional capacity issues, achieved by contracting appropriately with TAs.

53. MEUG/NZIER agreed that the regulator does require certainty that a reliability investment will happen, but noted that this applies equally to transmission investments as to TA investments.

54. Orion agreed that the regulatory certainty issue may indeed exist, but suggested that the risk of insufficient certainty could be mitigated by adopting locational transmission pricing.

55. Several other submitters noted that they believe regulatory certainty to be a valid issue.

What do submitters believe are the key problems?

56. Many submitters, (including both those that agreed that free rider and commitment issues exist, and those that did not agree), suggested that the key problems with encouraging investment in efficient TAs actually arise from the Commission's approach to the GIT and transmission pricing.

57. With regard to transmission pricing, the following points summarise the general views put forward:

    a) the choice of transmission pricing methodology is very important to provide the correct price signals to achieve optimal investment. Without clear information on the cost of transmission into a region, incentives to

[8] Section 4.2 of the Consultation Paper discusses the regulatory certainty issue. Regulatory certainty arguments for procurement are based on the premise that it may be difficult for the Commission to justify a decision to deter reliability investment proposals from Transpower *on the prospect* that TAs will eventuate within timeframes required to avoid supply shortages. The Commission's assessment of this issue (paragraph 172) is that it does provide some rationale for procurement, provided dynamic efficiency losses from procurement are less than the cost savings from utilising TAs in preference to grid investment.

investigate some energy supply solutions are not strong enough, and the optimal level of TA investment will not occur; and

b) locational pricing of interconnection transmission services, together with some other measures, could enhance market response. Similarly, replacing the use of anytime maximum demand with coincident peak demand in the pricing calculation would provide better investment signals.

58. With regard to the GIT, the following points summarise the general views put forward:

a) the current GIT sequencing[9] is an issue. It is disjointed, which exacerbates the "either grid investment or TA" paradigm, and is likely to discourage Transpower from considering TAs as part of preparing a GUP; and

b) considering TAs at the same time as transmission could allow for combined (transmission, generation and demand-side) solutions. This could be carried out by the Grid Owner[10] or by the Commission when it evaluates Transpower's GUP.

59. Both locational transmission pricing and the GIT process are discussed further below in the section on 'Other Options', under the heading of 'Enhanced Market Response Option'.

60. A number of other reasons were put forward to explain why (aside for the reasons proposed in the Commission's problem definition) there may not be sufficient incentives for investment in TAs. Whereas the transmission pricing and GIT issues outlined above were discussed in many submissions, the following items were noted by fewer submitters:

a) *Capacity pricing*: Several submitters suggested that signals or investment are not complete because capacity is not explicitly valued. Not having "VoLL pricing"[11] in shortage situations results in less than optimal signals for capacity expansion. Just as the market does not provide incentives to locate generation where it is needed from a transmission perspective, it has also failed to provide sufficient capacity, because there is no reward for doing so;

b) *Distribution company valuations*: A submitter suggested that disincentives to invest in alternatives arise from the optimised deprival valuation (**ODV**) rules for network assets. Under these rules, alternative distribution lines are not recognised, as they are often considered redundant and are therefore, required to be optimised out of the asset base of the lines company;

[9] Transpower proposes a GUP, which the Commission considers separately from it's consideration of TAs.

[10] Similar to the approach taken in the National Electricity Market in Australia. Under such an arrangement, the Grid Owner is authorised to contract for TAs, and recover the costs.

[11] Value of Lost Load pricing. Under VoLL pricing, capacity shortages are reflected in final prices by solving SPD using a generator in the constrained region offered at the VoLL price. Without VoLL pricing, SPD is resolved in order to achieve a feasible solution, and shortages are not reflected in final prices.

c) *Price threshold regime and network price signals*: Submitters suggested that because the price threshold regime has capped prices, it has made it more difficult for line companies to make a return on capital investments. One noted that, prior to the introduction of this regime, lines businesses faced incentives to pass on both transmission and distribution pricing signals. This has now reduced for transmission pricing signals, given the pass-through arrangements applying under the regime. In addition, several submitters suggested a key problem is insufficient use of transmission and distribution capacity price signals in the pricing methodologies applied by distribution companies ;

d) *Uncertainty*: One submitter believes that uncertainty is the key problem, including uncertainty with regard to fuel supplies, government policy on carbon taxation, and Resource Management Act 1991 (**RMA**) processes;

e) *Demand side response*: A submitter suggested that markets not enabling significant demand side responses is a key problem;

f) *Lack of interval metering;* and

g) *EIRA (1998)*: Several submitters suggested that EIRA (together with the Commerce Amendment Act 2001), through not allowing network companies to generate or retail electricity, reduces TA investment.

4.1.3 Discussion

61. While many submitters agreed with the problem definition proposed by the Commission, many of them also agreed that the problems could be at least partially addressed through the use of locational transmission pricing and amendments to the grid investment test. A number of other proposals for market developments to address these issues were also put forward.

62. From an efficiency perspective, the Commission notes that it is often preferable to address inefficiencies by targeting intervention at the source of the issue, rather than the problems that arise as a result of the issue. In the case of TAs then, it may be preferable to address free rider problems directly (if it is accepted that there are free rider problems, and submitters are divided on this point), rather than addressing one of the outcomes of the problems (i.e. the lack of TA investment).

Submitters' proposals

63. Several of the proposals put forward are worthy of further consideration, and these are discussed in more detail in the section on 'Other Options', under the heading of 'Enhanced Market Response Option'. These include:

a) locational pricing of transmission, which has previously been put aside by the Commission in favour of postage stamp pricing, partially because it is considered very complex. Although, the Commission notes that development of the details of a TA procurement scheme may also be complex;

b) lack of an explicit value for capacity; and

c) legislation that prevents distribution companies from making significant investments in local generation.

64. As noted, locational pricing is discussed elsewhere in this paper, but the Commission notes that it would be unwise to stop work on developing a TA framework, until transmission pricing is resolved.

65. The Commission does not consider that the sequencing of the GIT raises barriers to the development of TAs. As set out in Appendix 1 of the consultation paper, the GIT explicitly requires the consideration of TAs and Transpower is able to propose TAs as part of the GUP. There is no barrier to integrated consideration of transmission investment and TAs.

Approach to the GIT

66. As previously indicated, the Commission intends to consider further the sequence and form of approval given for large grid investment projects to allow it to take a final decision committing construction costs closer to the time the grid upgrade is required and therefore provide opportunity for generation and other alternatives to come forward. The Commission is proposing to consult on a rule change shortly to enable a revised approval process for grid upgrades and to impose conditions on approval. However, this approach could impose additional costs on consumers if the project did not proceed and still may not provide an appropriate time scale, especially for demand side or network alternatives.

67. More importantly, announcements of new generation (with appropriate resource consents) still leaves the Commission exposed to the risk that plant may be deferred or abandoned by the generator, without consideration of the consequences for the grid and too late for a grid upgrade to occur. This may make it difficult for the Commission to defer approval of transmission, even if it considers that generation is a cost effective alternative to transmission investment.

68. In regard to Transpower's proposal to require the grid owner to consider TAs within the GUP, the Commission note that Transpower is able to consider TAs within the current GUP process.

Evidence regarding TAs

69. The Commission considers that there is clear evidence that TAs have the potential to avoid or defer costly transmission upgrades and that it is unlikely that TAs will compete effectively against transmission upgrades under current regulatory arrangements. The Commission notes that previous TAs have been developed in an environment where the grid operator has to obtain agreement from the beneficiaries to proceed with grid investment and that many of the TAs have occurred for connection rather than interconnection assets.

70. The regulatory ability for Transpower to recover costs removes the constraint on Transpower of having to demonstrate to beneficiaries of the upgrade, that an upgrade is optimal and that TAs are not a reasonable or cost effective

solution. While the new regulatory settings address free rider issues with transmission upgrades, they also dampen the incentives for the development of TAs. Therefore, the citing of examples of TAs under the previous regulatory settings endorse rather than contradict the Commission's problem definition.

71. In particular, the Commission notes the example of the proposed Bay of Plenty capacity reserve (demand inter-trip) scheme. This scheme was developed by Norske Skog in response to Transpower proposed transmission upgrade of $50 million (the scheme was estimated to cost approximately $1.5 million). The capacity reserve scheme was estimated to provide around five years delay to the transmission upgrade. Norske Skog had strong incentives to develop the capacity reserve scheme, as under previous grid arrangements it needed to fund the upgrade or persuade other users to do so. In response to the proposed scheme, Transpower developed a tactical transmission upgrade and deferred the proposed $50m upgrade. Subsequently, new generation and reduced demand further delayed the need for any investment.

72. The Commission notes the submission from Todd Energy for Auckland TAs, on the potential for constructing a number of gas-fired power stations as a substitute for the Auckland grid upgrade as further evidence of the potential for TAs to be developed as a substitute for grid investment.

73. Transpower is proposing to spend $1.5 billion upgrading the National Grid by 2010 and more than $100m per annum from then until 2020. In light of this significant and sustained grid investment and evidence of cost effective TAs, TAs clearly have significant potential value.

Risk management

74. The Commission agrees that proposals which may be considered as transmission alternatives may also be useful for risk management, either in emergencies or during construction period for new transmission investment. However, Transpower is able to take account of these opportunities either as part of a GUP or in its system operator role. The Commission proposes to consider potential of transmission alternatives for risk management in the draft decision paper.

4.1.4 Conclusions

75. Following consultation, no arguments were delivered that lead the Commission to believe that the problem definition is fundamentally incorrect, particularly in regard to certainty for regulatory decision-making. Many of the criticisms of the problem definition suggest that the Commission should consider alternative approaches to addressing the problem such as amending the regulatory framework. The Commission accepts that it is valuable to consider these approaches further, but continues to believe that the problems inhibiting the development of TAs may need to be addressed more directly, at least for an interim period.

76. A list of areas that submitters believe should be addressed is discussed from paragraph 151 of this paper.

4.2 Submissions regarding evaluation criteria

4.2.1 The consultation paper

77. The evaluation criteria listed in the consultation paper[12] are as follows:

a) promote a level playing field between grid investments and TAs, and between alternative types of TAs, so that the lowest cost options are achieved consistent with grid reliability standards;

b) maximise opportunities for innovation in the provision of TAs to reduce the cost of electricity over the long run;

c) provide reasonable certainty that TA investments will occur within required timeframes (and will operate when required);

d) promote certainty for investment in the grid and investment by grid users;

e) minimise adverse affects on the competitive sectors of the market (i.e. minimise 'slippery slope' risks);

f) be consistent with the GIT and other work streams; and

g) minimise administration and compliance costs.

78. The consultation paper (question 1) asks submitters whether they agree with the evaluation criteria and the weighting given to each criterion. It asks that if submitters disagree, they suggest what criteria and weightings should be used.

4.2.2 Submissions

General comments

79. Several submitters noted that the criteria were a good cross section of the issues, though some questioned the weighting applied to each.

80. Others were not satisfied with the criteria or the weightings, suggesting they were not consistent with Government policy and the Rules:

a) MRP suggested that the criteria confuse "means" with "ends", for example, level playing field for transmission and TAs is a means for minimising the cost of electricity supply. It suggested that evaluation criteria should be driven off the Commission's principal objectives;

b) Meridian suggested that the emphasis of the criteria conflicts with central economic efficiency themes set out in the Electricity Act, the GPS, and the GIT. It proposed that criteria be revised to more transparently reflect these objectives and focus on the problem that the regulation is seeking to address;

[12] Paragraph 14 of the consultation paper.

c) Bryan Leyland suggested that the GPS's requirement for downward pressure on prices should be examined explicitly, rather than assuming that market arrangements will deliver this;

d) EECA noted concern that the Commission's and EECA's objectives with regard to demand side management, electricity efficiency and renewable generation are not explicitly included in the evaluation criteria. Similarly, SEF suggested that more weight should be given to the objectives of environmental sustainability and efficiency;

e) Genesis noted that it disagrees with the approach of using selection criteria rather than a cost benefit analysis that includes allocative, productive and dynamic efficiency assessments for each option; and

f) Solid Energy suggested that the evaluation criteria include the acknowledgement of "fatal flaws" in the evaluation scores, where a fatal flaw under any criteria results in a maximum negative score.

Specific comments

81. The following specific proposals to amend the evaluation criteria were made:

a) *Orion*: Amend criterion (a) to reflect the potential for combination (generation, demand-side management (**DSM**) and transmission) solutions, by inserting the words "combination of" prior to the word "options". Reduce the weighting given to criterion (e) "slippery slope";

b) *Comalco*: Increase focus on maximising dynamic efficiency in TA and transmission investment by weighting criterion (a) "level playing field" highest, and criterion (c) "Promoting certainty of investment" also highly. Remove criterion (b) "maximising innovation opportunities", with a lower weighting, and retain the remaining criteria;

c) *MEUG/NZIER*: Reword criterion (a) to remove the reference to "lowest cost options" and replace it with "options ranked highest under the GIT". Restate criteria (b) and (e) – both of which relate to efficiency objectives – in broader market efficiency terms. Merge criteria (c) and (d) as these overlap. Delete criterion (f) relating to consistency with other work streams, as it is a case of "the tail wagging the dog". Assuming the intent was to refer to consistency with the GIT and other transmission/security of supply policies, this already fits under criterion (a). Delete criterion (g) regarding minimising administrative and compliance costs as this is part of the overall net benefits under criterion (a) and should be incorporated into the GIT as one aspect of overall costs. These proposed changes result in only three criteria remaining. Weight criteria (a) and (c/d) higher than criterion (b/e); and

d) *Transpower*: Delete criterion (a), "promotes level playing field" because transmission is regulated, but TAs are part of the competitive market, so there should not be a level playing field. Add the following criteria:

i.) "Is of national benefit to NZ" (i.e. broader than net industry benefit);

ii.) "Is a consistent component of an overall integrated market and regulatory design";

iii.) "Assures that Grid Reliability Standards will be met"; and

iv.) Subjects electricity costs and prices to downward pressure.

4.2.3 Discussion

82. As a general comment, some submitters believe the evaluation criteria should in effect be the principal objectives and specific outcomes required of the Commission by the Electricity Act and the GPS. As the evaluation criteria proposed in the Consultation Paper are intended to provide a more specific interpretation of the Commission's principal objectives, as they relate to the issue of transmission alternatives, there appears to be little value in adopting higher-level efficiency objectives.

83. The Commission does not believe that the level playing field criterion (criterion a) should be deleted, as some forms of TA are, to some degree, competitive with grid investment. We also note the level playing field criterion is only relevant to those selected TA types.

84. We believe that the other comments regarding criterion (a) are useful, and it should therefore be amended to state: Promote a level playing field between grid investments and TAs, and between alternative types of TAs, so that the combination of options ranked highest under the GIT are achieved, consistent with grid reliability standards.

85. The Commission suggests that criteria (b) and (e) should be retained in their current form. Combining them and adopting a broader market efficiency term, as suggested in the MEUG/NZIER submission, reduces the transparency of decision-making because the effects of the options on criteria (b) and (e) are often in opposite directions. It is easier to show these effects separately, rather than combine them but then explain their individual components.

86. Although criteria (c) and (d) are both about uncertainty, it is not clear that they should be combined, as suggested by MEUG/NZIER. Criterion (c) refers to providing reasonable certainty *to regulatory agencies* making decisions about grid investment versus TA investment, whereas criterion (d) refers to promoting certainty *for grid investors and grid users*. These are quite different issues. In this context, reducing uncertainty for grid users depends on the framework and manner in which the Commission and other regulatory bodies make grid investment decisions, whereas uncertainty for the Commission depends on the nature of the TA regime and the manner in TA providers make decisions.

87. If criteria (c) and (d) were combined into one criterion it would be necessary to increase the weighting of the criterion to ensure uncertainty is weighted appropriately, particularly as the uncertainty in (c) is part of the fundamental concern about relying on market responses for TA investment (option 1).

88. In our view, it would be better to retain separate criteria but revise their wording so that it is clear they refer to different aspects of uncertainty. Criterion (c) could be restated to read: Provide reasonable certainty to the

Commission and other regulatory agencies that TA investments will occur within required timeframes (and will operate when required). Criterion (d) could be restated to read: Promote certainty for grid investors and grid users.

89. We suggest that criterion (f) should be restated as: Be a consistent component of an overall integrated market and regulatory design.

90. The Commission suggests that criterion (g) should be retained, as it is not covered under criterion (a). Criterion (a) refers to promoting a level playing field, which will bring efficiency benefits, whereas criterion (g) will bring other efficiency benefits in the form of lower resource costs associated with administration and compliance activities.

91. With regard to Transpower's proposal to add a "national benefit" criterion, the Commission notes that this is outside the Commission's jurisdiction. This issue was previously considered by the Ministry of Economic Development as part of the development of part F and by the Commission as part of the development of the GIT.

92. The Commission notes that grid reliability standards and downward pressure on costs and prices are already captured within the GIT process. Furthermore, grid reliability standards are included in criterion (a), and downward pressure on costs and prices are implicit in criterion (b) – that is, innovations either reduce costs and prices directly or enhance the quality and variety of goods and services available to society.

4.2.4 Conclusions

93. The Commission agrees that some minor amendments to the evaluation criteria are desirable, as a result of comments from submitters. An initial assessment of changes is outlined in the discussion section below.

4.3 Dynamic efficiency (slippery slope) issues

4.3.1 The consultation paper

94. The Commission identified 'slippery slope' risks[13] arising from undermined incentives for market participants to deliver required outcomes, and poor quality information making it difficult to target intervention to the source of the problem.

95. The Commission considered that concerns about slippery slope risks had some validity and that the detailed design of any TA procurement regime was important to address this issue.

[13] The Commission defined slippery slope issues in the consultation paper as the potentially adverse effects on the competitive sectors of the market. The Commission considered that the slippery slope risks might arise from undermined incentives for market participants to provide the desired outcomes and from the regulator having poor quality information.

96. The Commission's consultation paper asked whether submitters agree with the general framework regarding slippery slope risk, and if not, what alternative framework should the Commission consider, and whether submitters agree that slippery slope risks depend greatly on the details of the TA procurement regime. They were also asked whether they believe that slippery slope risks can be managed under the minimal CP and limited DP options.

4.3.2 Submissions

97. A number of submitters argued that the consultation paper understated the slippery slope risks for the generation market, investment and dynamic efficiency, resulting from regulation. Submitters argued that it would be difficult to distinguish between genuine TAs (that would lower transmission costs and would not have been introduced if the market had being relied on) and other potential transmission alternatives.

98. A number of submitters questioned whether the slippery slope risks would be manageable, under options 2 to 5. One submitter argued it was unclear how the Commission proposed to target the source of the market inefficiency or how it would use incentives on, and the information of, market participants. Another argued that, to the extent that TAs extend the influence of the Commission into the energy market, it will create substantial risks that central planning will become a reality. This submitter argued that the proposed tests for the minimal CP option would not manage the slippery slope risks as these could still be gamed by participants and that, although limited DP manages these options better, it still introduced unwarranted complexity and administration costs through penalty reward and payment.

99. Genesis argued that there should be a clear demarcation between regulated intervention for TAs and energy market investments that occur in response to price signals. In the absence of a clear distinction between transmission investment and energy, Genesis considered that all funding mechanisms in the consultation paper may delay market investment, result in gaming and introduce a central decision making dimension to energy market investments.

100. Transpower argued that a central TA procurement regime could introduce significant price impacts in deliberately constrained regions and that the Commission would have to restrict generator offers. It argued that this would severely damage the energy market and distort price signals for the market to manage congestion efficiently and therefore system security.

101. Orion considers that the 'slippery slope' arguments promulgated by major generators are somewhat overstated. It noted that the generation market is itself an administrative creation and that where transmission investment and generation can be viewed as substitutes, administrative decisions on transmission investment will inevitably affect the generation market. It considered that there is no evidence to suggest that central planning of TAs will inevitably undermine the competitiveness of the generation market, or that it will have a materially different impact on the generation market than central planning of transmission through the GIT process.

102. Orion considered that the 'slippery slope' problem has been framed as one of extremes, whereas it is more likely to be a question of degree. It believes it is possible to develop principles to prevent generator gaming and crowding out of competitive generation by centralised decision making. It considered that this can be achieved by a clear framework that sets limited criteria for making payments to generators and which constrains the behaviour of generators receiving payment such as restrictions on generation TAs setting spot prices where they are used as network support. It considered the Commission's proposed tests for minimum CP to be very difficult to implement and that the implementation of the tests has not been fully described.

103. Contact considers that most of the slippery slope issues have been addressed well in the consultation paper, but its key concerns are:

    a) Under CP options, only generation plants that receive contracts will receive payment, although all plant that contributes capacity at a time of need provides value. This will adversely affect investment and retirement decisions of non-centrally procured generators and will send distorted signals to consumers relating to the cost of consumption at different times of the day;

    b) Centrally procured plants will have fewer opportunities for capturing synergies of operating not only to deliver capacity, but also to operate in the energy market, provide dry year reserve and optimise the use of gas reserves; and

    c) CP mechanisms will be exposed to significant risks of gaming, as proponents of schemes take advantage of the informational asymmetries between the regulator and providers to extract rents.

104. A number of submitters agreed that the Commission's approach to the 'slippery slope' risk was reasonable and that the risks depend on the details of the scheme and could best be managed under a minimal CP scheme.

105. Other submitters considered that the 'slippery slope' risk is overstated as most generators cannot choose their location and will end up locating where there is no incremental benefit. One submitter considered that the simplicity of the universal CP option will make 'slippery slope' issues more apparent, if they arise.

106. NZIER (on behalf of MEUG) considered the 'slippery slope' risk to be part of a wider issue of ensuring that markets for electricity operate in an efficient manner.

107. One submitter argued that the meaning of the term 'slippery slope' is unclear and that it may mean the current regulatory regime, and, in any case, it was not obvious that central planning would lead to worse outcomes than a market based approach.

4.3.3 Discussion

108. The Commission acknowledges the significant potential 'slippery slope' risks in the procurement of transmission alternatives. A procurement arrangement

that involves purchasing generation capacity will create risks around the potential distortion of market outcomes and the substitution of the judgement of a central authority for market interactions. However, restricting the procurement of TAs to avoid potential risks to the energy market forgoes the opportunity to make efficient trade offs between generation and transmission. The Commission agrees that while all procurement options have some potential slippery slope risks, that the details of the procurement arrangements will determine the extent of the risk.

109. The Commission agrees that slippery slope issues are part of the wider issue of dynamic efficiency. For the avoidance of doubt, the Commission will refer to slippery slope issues as dynamic efficiency issues. However, it should be noted that the particular focus is on 'regulatory creep' risks.

Wealth transfers versus efficiency effects

110. It is important to distinguish between the wealth transfer and efficiency impacts of transmission alternatives[14]. TAs are intended to improve efficiency rather than minimise wealth transfers between consumers and generators. TAs may result in higher prices at constrained nodes than if transmission had been constructed. To the extent that generators are able to exercise market power at the time of constraints, then consumers will pay higher prices and producers will receive higher profits. The efficiency loss is limited to consumers who choose not to consume electricity at the higher price, but who would have been prepared to purchase at price equal to cost. The efficiency losses from higher prices will be much less than overall losses to consumers arising from wealth transfers to generators.

111. The transfers may be much smaller than apparent from electricity prices, as TA providers will take account of this revenue when bidding for TA contracts. If the market for TAs is competitive, then the expected gains from selling energy during constrained periods will be bid into the tender price. Overall, consumers will not be worse off. However the impact on individual consumers will vary, with consumers exposed to higher spot prices worse off and consumers who benefit from reduced transmission costs better off.

112. There is a risk that higher prices may lead to pressure to introduce price caps. The Commission acknowledges this risk, but it is not proposed to regulate prices in any option, aside from the universal CP option.

Gaming risks

113. There are two gaming risks: TA providers receiving payment for plant/load reduction they would have provided anyway; and existing generators who may retire plant early to obtain TA payments for providing previously available capacity. The former risk concerned a number of submitters. This risk is best addressed by a competitive tender process for capacity. Provided the tender is competitive, providers will not be able to extract additional returns from providing capacity they would have provided. For example, if there were a

[14] The Commission that acknowledges that both effects may need to be considered when assessing options for enabling transmission alternatives.

number of competing generation TAs that could go ahead without payment (and assuming they were not included in the GIT), then TA suppliers would offer at or close to a zero price in the TA tender. The TA provider would benefit from pre-empting the entry of competing generation plant, but would be unable to extract additional payments from acting as a TA, due to the threat of rival bidders undercutting them.

114. If the tender process is not reasonably competitive, then the TA provider may be able to extract payment above it's cost from the tender process. However, such an outcome does not necessarily reduce efficiency; it is a wealth transfer from consumers (who ultimately pay transmission and energy charges).

115. Efficiency may be reduced if the TA procurement process adversely changed the decision process of a generator or other TA provider. For example, a generator decides not to offer a potential generation plant due to uncertainty about fuel supply at the time of the TA tender and a rival generator wins the tender process to provide a TA with a higher cost plant. Entry is no longer viable for a second plant until market conditions change. However, in the absence of the TA process with a firm timeline set by the Commission, both generators may have waited and the more efficient generator may have entered first.

116. From the perspective of the generation market alone, the TA procurement process has induced an inefficient outcome by requiring a premature decision on new generation. However, such an outcome will only occur if the TA substituted for more expensive transmission investment. Therefore, taking account of both the transmission and generation markets, the TA procurement process has reduced costs and improved efficiency.

Plant retirement

117. A second gaming concern is that TA procurement may induce inefficient plant retirement decisions under the CP options. This risk does not occur under the decentralised procurement options because all generation within a constrained region receive capacity payments.

118. Under central procurement, retirement of existing generation within a constrained region may result in the procurement agent needing to procure more capacity. This may raise the possibility of generators announcing retirement of existing generation and seeking the TA contracts to provide the same generation. The extent of competition for TA provision may constrain such behaviour. A competitive market will increase the risk that withdrawn capacity would not be successful in a tender. However, as existing capacity will benefit from sunk costs, it is unlikely that new generation alternatives could compete with existing sources, although network or demand side TAs may be closer in cost.

119. This potential issue could be addressed by the Commission setting rules which make retired generation ineligible for TA payments. For example, any existing plant (or possibly level of existing capacity from a currently used site) could be made ineligible for TA contracts for a fixed period of time after their retirement (e.g. seven years).

120. Although this approach would deter withdrawal and re-entry of the same capacity as a TA, it would provide inefficient incentives for early withdrawal of existing capacity and replacement with new capacity eligible for TA contracts. This is because existing capacity is ineligible for TA contracts, whereas new plant is eligible. A firm considering the optimal withdrawal date for an existing plant and replacement with new capacity would choose to withdraw capacity at an earlier date (than if the rule did not exist), given the possibility of winning TA contracts for new plant. However, provided TA payments are small relative to the total cost of a plant, and in light of the significant sunk cost of new plants, the incentives for early retirement may be negligible.

121. An alternative approach would be to adopt the rule that any retired plant receiving a TA contract would be required to offer into the market at their short-run marginal cost (**SRMC**) and receive only their SRMC for energy supplied to the market. The latter would be achieved by specifying in the TA contract a requirement for excess revenues received from the Clearing Manager to be paid to the procurement agent.

122. This rule removes incentives for parties to artificially retire plant. If plant retirement is genuine then a TA contract will be attractive because without that contract the retired plant earns insufficient revenue above SRMC to justify staying in business. On the other hand, if plant retirement is artificial, then in the absence of a TA contract the plant can earn a return above SRMC sufficient to justify keeping the plant in operation. As the TA contract pays just enough to keep the retired plant in operation, generators will only choose the TA contract when market sources of revenue are insufficient to keep the plant in operation – that is, only when retirement is genuine.

123. The key to this approach is to accurately determine the SRMC of retired plant, which is probably not a significant problem for thermal plants. If the tender is not competitive then retired plant may earn an overall positive return, but as the plant has already sunk its fixed costs the procurement agency could enter into short-term TA contracts with existing plant (e.g. one year contracts) so that they had to compete frequently for the TA contract.

The Australian NEM approach

124. The Commission notes that the dynamic efficiency risks of central procurement are likely to be similar for the Australian National Electricity Market (**NEM**) model, which was proposed by a number of submitters. While under this model, the grid owner rather than the system operator is responsible for procurement, similar risks around gaming the procurement process appear to exist. A description of the Australian NEM model is attached as Appendix A.

125. As the NEM model involves capping prices[15] during times of constraint, the potential impact on the efficient workings of the wholesale market is likely to be greater than under the minimal CP option. While NERA argue that below cost dispatch is not possible as the TA also receives compensation via the TA contract, this ignores the possibility that generation may be dispatched where

[15] Generators providing a network support function may not be used to determine the dispatch price.

the marginal cost of the generation is greater than buyers' willingness to pay. This is inefficient, regardless of whether the generator also receives compensation via the TA contract.

126. The development of a framework for TAs is part of the Commission's work programme that will be completed before the implementation of the GIT. Therefore, it seems unlikely that uncertainty about TAs will have a material effect on generation investment, prior to the application of the GIT. All generation investment decisions will be affected by the uncertainty around grid investment.

127. Once a TA framework is adopted (if a CP option is selected), it may be argued that generators may hold out on investment in constrained areas in the expectation of receiving TA contracts. However, generation investment is likely to be determined by a GIT process for the grid upgrade, even in the absence of a TA process. The possibility of receiving payments under TA procurement may provide incentives for generators to delay construction of new plant. However, if the market is competitive, a delay may allow a competing generator to go ahead with a project and pre-empt the TA procurement process. Therefore, the Commission does not consider that TA procurement is likely to result in substantial delay to new generation investment. Finally, the TA framework may have the potential to induce additional generation investment, for example, Todd Energy's proposed Auckland generators.

128. The Commission does not consider that central procurement will be significantly less able to capture synergies from the offering plant in the energy market. It is expected that TA providers will take account of potential revenue from energy and reserve markets, when preparing TA bids. Participation in the dry-year reserve scheme will be limited by the rules around dry-year reserve and the requirement for reserve, under either central or decentralised procurement.

129. The Commission accepts that the tests for the minimal CP option will not be completely effective at managing free riding issues. However, on balance the tests are likely to be beneficial in mitigating the potentially distortionary impacts of central procurement. The tests will be further developed, if minimal central procurement is pursued further, following the decision paper.

4.3.4 Conclusions

130. The Commission considers that dynamic efficiency risks are a key issue with the development of TAs. However, it does not accept that dynamic efficiency risks are so large or invariant with the particular details of the options that enablement of TAs should not be considered further. The Commission will take account of slippery slope risks in the assessment of options in the final decision paper and in the development of any subsequent rule change (if required).

4.4 Submitters' assessment of options and preferred option

4.4.1 Options proposed in the consultation paper

131. This consultation paper considers five broad options for facilitating TAs:

a) *Option 1: market response*. Under this approach the Commission assists market participants to identify and evaluate investments in TAs,[16] but relies on investments in TAs occurring in response to market conditions and grid expansion decisions. This is the status quo under the Rules;

b) *Option 2: universal central procurement (universal CP)*. Under this approach a central body determines the total quantity of TAs to be procured in each region *to meet reliability of supply needs*, and conducts a tender to procure those TAs.[17] The procurement contracts under this option specify maximum prices that generator TAs are allowed to offer energy into the market, and place other operational constraints on them;

c) *Option 3: minimal central procurement (minimal CP)*. This approach is similar to option 2, but with no price constraints and fewer operational constraints. It also includes tests to try to avoid funding TAs that would occur in response to market conditions;

d) *Option 4: limited decentralised procurement (limited DP)*. As with the CP approaches (options 2 and 3), a central body determines the total quantity of TAs to be procured in each region *to meet reliability of supply needs*. Rather than conduct tenders, the central body assigns capacity obligations to demand-side entities (DSEs) to procure TAs, based on their share of regional peak demand. Under this option a central body monitors DSEs' compliance with their capacity obligations and verifies that TAs meet reliability requirements. Financial penalties are imposed on DSEs for not meeting their obligations; and

e) *Option 5: full decentralised procurement (full DP) or regional capacity contracts (RCC)*. Under this option DSEs, rather than a central body, forecast their own load and pay penalties for failing to meet their capacity obligation and for inaccurately forecasting demand (when compared with real time demand). In contrast to the limited DP approach, the central body would not be able to determine under-performance until real time. This option has been developed by Contact.[18]

132. The consultation paper proposed that, if option 2, 3, or 4 were selected, the System Operator would undertake the role of central procurement agency. The consultation paper also noted the Commission is only considering TA

[16] As required by rule 2.2 of section III of part F of the Rules.
[17] Note that the identity of the central body is discussed further in section 3.3.
[18] As Contact refers to the option it has developed as regional capacity contracts, the Commission adopts the same terminology when discussing Contact's option specifically. The Commission also refers to it more generally as a DP (decentralised procurement) option. Contact's proposal is detailed in a paper available on its website at: http://www.mycontact.co.nz/view?page=/forinvestment/publications/governmentsubmissions.

arrangements needed to achieve reliability of supply, rather than arrangements to facilitate TAs generally.

4.4.2 Submitter's preferred options

133. Meridian, Genesis, Transpower and MRP noted a preference for option 1 (market response), though they suggested that it should be redefined to include some market design enhancements to address identified issues. A list of suggested enhancements is contained in the 'Submissions - Other Options' section (below). Vector noted that it prefers a market-based alternatives mechanism, with under-investment in TAs directly addressed through market design.

134. Option 2 (universal CP) was the preference of Trustpower and Norske Skog, the former supporting this option only under a postage stamp transmission pricing regime. Trustpower noted that it believed the slippery slope concerns discussed in the consultation paper were overstated, and could be managed sufficiently to make this option desirable.

135. Option 3 (minimal CP) was the preferred option of Comalco, Solid Energy, and MEUG/NZIER. A variation on this option, involving inclusion of TAs in the Grid Owner's GUP, was the second preference of Transpower, and this variant is discussed in the 'Other Options' section of this paper below. The same variant was also noted by a number of other submitters as a possible option to be considered, though they were unconvinced that this approach does not also have slippery slope risks. Contact suggested that minimal CP could be applied for the purposes of emergency risk management only.

136. Option 4 (limited DP) was the preferred option of Contact, and a variation on minimal DP[19] was the preferred option of Orion. In the event that there is locational pricing, Trustpower also prefers the limited DP option.

137. Option 5 (regional capacity contracts) was Contact's second preference. No submitters stated this as their preferred option.

138. All other submitters did not state a preferred option.

4.4.3 Submitter's evaluation of the Commission's options

139. This section provides an outline of the rationale put forward by submitters in opposition to each option.

140. NERA (on behalf of MRP) opposed the procurement options in general, noting that it believes that they only address the barriers to optimal investment to a limited extent:

    a) While they may address the certainty issue to some extent, NERA considers that the certainty problem is actually caused by the Commission not requiring Transpower to consider TAs as part of the GUP;

[19] See 'Submissions - Other Options' section below for a discussion of the variation.

b) None of the procurement options address any cultural preference by Transpower for transmission investment over TAs; and

c) None of the procurement options address the GIT sequencing problem.

Comments specific to the DP options

141. Regarding decentralised procurement options in general, a number of practical implementation issues were noted by submitters, including quantity determination (doing this without making assumptions about transmission investment), practical issues relating to data and processes, including allocation, issues with verification and with integration into the dispatch process, and contract/counterparty issues.

142. NERA noted that the decentralised procurement options do allow local providers to choose between different TA providers and therefore do address information problems to some extent. However, the decentralised procurement options still involve initial decisions on the key issue of grid upgrades by the Commission and Transpower, so local participants are not really making a genuine choice between transmission investment and TAs.

143. Orion agreed that decentralised procurement options will result in lower procurement costs but disagreed that they will be administratively more costly, noting that this is inconsistent with its own experience.

144. Solid Energy suggested that decentralised procurement options will not provide sufficient investment certainty.

145. EECA noted that minimal DP will encourage innovation and diversity with respect to demand-side initiatives, while minimising slippery slope implications of procurement options in general.

146. Solid Energy noted that RCC may enable retailers to entrench positions, to the detriment of competition.

Comments specific to the CP options

147. NERA noted that central procurement options do not address Transpower's information problems (they will not have the best information on TA investments at the local level). In addition, these options do not address Transpower's likely issue regarding their perception of the riskiness of TAs compared with transmission investment.

148. Regarding minimal CP, Meridian noted that this option has fewer 'slippery slope' implications if only demand side is eligible for regulated approval.

149. Regarding universal CP, several submitters noted that this option has substantial 'slippery slope' implications. However, Trustpower considered that dynamic efficiency losses under this option are overstated in the paper.

Comments specific to the market response option

150. Solid Energy suggested that the market response option is fatally flawed in respect of TA investment and operational uncertainty.

4.4.4 Submissions – other options

Enhanced market response

151. Several submitters proposed revision of the market response option into a 'market response with enhancements' option, which amended aspects of the market design to address barriers to investment in TAs. A number of submitters suggested amendments to the grid investment processes and to the transmission pricing methodology, and a number of other enhancements were also proposed.

152. Proposed amendments to grid investment processes:

    a) Several submitters suggested splitting the approval process into two stages: (i) securing the route; and (ii) construction. Such an approach would enable more time for market-based new investment, and provide increased certainty for grid users. Under this proposal, transmission investment would be allowed to proceed up to the end of stage (i) even if potential TAs were identified. If TAs materialised, then the last stages of transmission investment could be delayed, but if not, transmission investment would proceed;

    b) Another submitter suggested amending the Rules to clarify that the Commission will not approve grid upgrades where TAs are considered adequate substitutes; and

    c) Another suggested that improved information provision would assist investors, by publishing part F information documents, and requesting Transpower improve its communications to grid users on grid upgrade plans.

153. A number of submitters suggested that changing the transmission pricing methodology to a locational pricing design would improve incentives for investment in TAs, such that a formal procurement mechanism may not be necessary. A range of options were suggested, including:

    a) Deeper connection/postage stamp interconnection;

    b) Locational pricing for new investments only;

    c) Locational pricing for interconnection or core grid assets only; and

    d) A simplified zonal locational pricing system.

154. It was noted that locational pricing can be difficult to design and implement, and may have perverse effects. For example, pricing at long run marginal cost (LRMC) would mean that transmission charges would be high when an upgrade is imminent, and low immediately after an investment is made. In addition, Contact noted that alternative forms of location-based charging for transmission (for example, charging users once an upgrade has occurred) will still suffer the free rider problem.

155. Other proposed enhancements to the market design that would improve the performance of the market response option (in terms of encouraging TA investment) included the following:

a) Several submitters suggested developing an explicit value for capacity, using capacity mechanisms and/or adopting Value of Lost Load (VoLL) pricing in the energy market for supply interruptions;

b) Several submitters proposed changes to electricity regulation to allow distribution companies to invest in generation and sell the output in a commercial manner;

c) One submitter suggested amending the Rules to make it mandatory for generators to offer available capacity, suggesting that this would address the reliability issues that many transmission investments are proposed to address.

Variations on the minimal CP option

156. Submitters put forward a number of variants on the minimal CP option, which may be divided into two areas:

a) A model based on that used in the Australian NEM; and

b) Placing limitations on the type of TAs that are eligible for procurement.

157. A number of submitters noted that, while they do not support procurement, if the Commission preferred a procurement option, the "NEM model" should be considered. Under this model, the Grid Owner is responsible for overall delivered transmission service and is entitled to recover the costs of TAs on the same basis as it does transmission costs. TAs are not allowed to set prices during TA periods and providers are funded outside of the market.

158. Submitters suggested that the NEM-type arrangement provides a much clearer contract and accountability model than the minimal CP option defined in the consultation paper. Constraints imposed on offer prices prevent TAs from exercising market power.

159. With regard to limiting the TAs that are eligible for procurement, several submitters proposed limiting the scope of procurement further than defined under the minimal CP option:

a) Meridian suggested that (though it does not support procurement) this could be limited to demand-side only,[20] and possibly funded through the Commission's energy efficiency fund. Alternatively, procurement could be limited to only non-core grid TAs;

b) Contact proposed that the Commission limit central procurement to emergency risk management projects to address urgent issues in Auckland and the upper South Island; and

c) Genesis suggested a much narrower definition of TA be adopted, where TAs include only those investments that provide equivalent services to transmission, and there is a clear delineation between competitive and regulated activities. They further suggested that if TAs operate in the energy market, they should not be able to set the price.

[20] Consistent with this, Meridian suggested that the Commission could consider undertaking some work on development of demand-side aggregators, and potential for using its energy efficiency fund to fund high value demand-side TAs.

Variations on the limited DP option

160. Orion noted that its preferred option is limited DP with enhancements to address the inconsistency of postage stamp pricing with decentralised procurement. The proposed enhancements are either:

    a) Implementing locational pricing; or

    b) Allocating capacity requirements between regions.

161. One submitter noted that, if a DP option is preferred, it would like to see further consideration given to implementing a CP option as an interim option until such time as the DP option can be implemented.

4.4.5 Discussion

162. We believe that some of the options developed by the submitters have potential to address the problems identified in the consultation paper.

163. The first of these is for the Commission to develop its understanding of the effect of postage stamp versus locational transmission pricing on incentives to invest in TAs. While a change to locational pricing would be likely to improve investment incentives, any locational pricing regime will also be imperfect. It is therefore important not to assume that this will provide the answer, but rather to investigate further the potential benefits of such a regime, and the degree to which these will be muted by imperfections in its real world application. As transmission pricing considers a broader set of issues than TAs it is possible that the optimal form of transmission pricing may not effectively address the problems with TAs. Further, it may be neither desirable or practical to defer consideration of the enablement of transmission alternatives until decisions are taken on transmission pricing.

164. The second area for further consideration is undertaking further investigations into the Australian (NEM) model for TA procurement by the Grid Owner. The Commission considers the NEM model to be a potential variant of the limited CP approach, although it notes the NEM model includes price constraints, which were part of the (more intrusive) universal CP approach.

165. While the Commission would like to consider the NEM option further, there are likely to be a number of potential issues with the grid owner acting as the procurement agent for TAs. NERA identified the following issues. Transpower may lack the appropriate incentives to develop and implement TAs, as price control arrangements may imply that they are unable to retain the cost savings benefits of TAs. Secondly, the grid owner may have a cultural preference for wires compared with non-wire solutions. Thirdly, Transpower will not have the best information about local power needs and potential least cost solutions in a given supply area.

166. The third aspect of market design we believe should be further considered relates to the value of capacity. In developing the RCC approach earlier this year, Contact was attempting to develop a regime that placed value on all capacity in a constrained region, as opposed to focussing on only new capacity. Funding only new capacity has dynamic efficiency risks as

discussed in detail in the consultation paper and earlier in this paper, particularly in regard to incentives for generators to game the procurement process, including as this relates to plant retirement. Centrally funding all capacity is not a desirable approach, but developing a market-based mechanism that infers a value for capacity could provide valuable incentives for new capacity investment. We believe that such an approach, including VoLL pricing for energy supply shortages, is worthy of further consideration.

167. A further area for work is the provision of information on opportunities for economic investment. Transpower is currently obliged to publish a grid reliability report (GRR) within six months of the publication of a statement of opportunities. The GRR sets out forecast demand and supply at each grid exit/grid injection point for the next 10 years and assesses whether the power system is reasonably expected to be in a secure state at each grid exit point over the next 10 year period and any planned proposals for addressing reliability issues. The Commission considers it may be desirable to produce a similar report for economic investment. This report would identify whether new investment is likely to be desirable in light of projected demand and supply over a 10-year period and any planned proposals to address this issue.

168. Finally, the Commission believes it should investigate arrangements to improve the ability and scope for distribution companies to invest in capacity.

4.4.6 Conclusions

169. The Commission proposes to investigate capacity arrangements and location transmission pricing as part of the market design work programme. The Commission considers the NEM option is a potential variant of minimal central procurement. Further details are provided in the general conclusion to this paper below.

4.5 Discussion regarding cost benefit analysis

4.5.1 The consultation paper

170. The consultation paper identified the following elements required estimation for a cost benefit analysis:

a) The avoided costs of transmission investment including capital and operating costs;

b) The value or cost of any quality differences between transmission and TAs, such as transmission losses, availability, and any improved trade-off between grid reliability and cost;

c) The option value of TAs due to the delay of transmission investment;

d) The administrative costs of procurement;

e) The cost of procuring TAs;

f) Any costs relating to sub-optimal procurement, such as procurement of the wrong type of TAs and procuring too many TAs; and

g) The impact on dynamic efficiency, such as the impact on investment in new generation.

171. The Commission considers that insufficient information was currently available to robustly estimate net benefits for any or all procurement options compared to the market response option. Therefore, the Commission did not estimate the net benefits on a quantitative basis for any of the procurement options.

4.5.2 Submissions

172. A number of submitters considered that the Commission should undertake a cost-benefit analysis (CBA) prior to taking a decision on the in-principle preferred option. MRP noted the approach of the Commerce Commission to undertake CBAs where feasible and the support of the Courts for this approach. Two submitters commissioned their own cost benefit analysis of the TA policy options.

173. Transpower commissioned a national benefit assessment of TAs by Castalia. Castalia estimated the following costs/benefits:

a) Benefit from deferred capital spending on transmission upgrade of $27m per annum;

b) Dis-benefit from higher transmission losses of $16m per annum;

c) Administration costs of TA procurement of $2m per annum;

d) TA provision costs of $3m per annum;

e) Static net benefits of $6m per annum; and

f) Dynamic efficiency losses of $70m per annum;

174. Transpower believes that the Commission's cost-benefit assessment needs to include: consumer price impacts, business investment confidence, and environmental impacts.

175. Meridian commissioned a net benefits analysis from CRA International. CRA concluded:

a) Generation TAs have potential to delay transmission investment for 1 to 5 years for a benefit of $18.1 to $79.6m, after allowing for reliability effects, and domestic demand response could delay transmission investment by 2 years for a deferral benefit $36.9m. Commercial interval/smart metering can delay transmission investment by 1 year to provide a deferral benefit of $18.2m;

b) There are some commercial incentives to pursue generation TA investment, although the viability of open cycle gas turbines (OCGT) and coal generation depend on the required rate of return and the viability of most other options depend on their assumed utilisation. The merits of subsidising generation TAs is questionable, given the commercial incentives to pursue these options; and

c) Commercial incentives to pursue demand management TAs are mixed and that even in cases where there are commercial incentives to pursue demand

management TAs, the available gains may not be sufficient to prompt firms and individuals to implement these options.

176. Contact considered that the CBA needed to account for the asymmetric price risk associated with too much versus too little capacity. While there is option value arising from the delay in transmission investment, it considered that an option analysis needs to allow for the long lead times and uncertainty over delays in commissioning. Contact considered that the CBA omitted to mention that some TA investment (peaker and reactive support) is likely to become redundant, if and when transmission investment occurs. Contact believed that the quality differences between TAs and transmission require further analysis, and considered that risks of sub-optimal and unnecessary procurement are unlikely to be managed effectively by the TA tender process, as TA's are potentially involved in a number of markets.

177. Orion agreed with the costs and benefits identified by the Commission, but considered that the Commission should take account of the security value that may be provided by demand side management and embedded generation options, both in the transmission construction period and after the transmission is installed.

4.5.3 Discussion

178. The Commission considers that a full cost-benefit analysis is required prior to any rule change to enable TAs. This will ensure that the Commission's proposed approach maximises net benefits compared to the counterfactual and other relevant alternatives.

179. In regard to the Castalia CBA, the Commission notes that:

a) Its 'cost of transmission' does not allow for any of the ongoing costs of operating and maintaining transmission, and nor does it appear to include any of the $65m physical contingency costs, which are part of Transpower's total cost estimate. It is also possible that easement costs would be avoided by deferral of transmission and this increases the benefits of deferral by one year would from $27m to $36m in 2010/11;

b) Contracting and administration costs of $2m per annum per 60 MW are estimated. The Commission considers these costs are likely to be much smaller as the procurement agent will use standard form contracts (share costs among different providers) and multi year contracts (share costs over years);

c) The estimated dynamic efficiency loss is predicated upon the Commission setting price caps on all generators within a constrained area. Most of the options developed by the Commission do not include such an approach. Castalia do not suggest or estimate dynamic efficiency losses without price caps. Secondly, the paper is unable to demonstrate a tight linkage between the potential problem arising from price caps and the size of the cost i.e. why is the cost 1% of new generation costs instead of 0.1% or 0.5% of new generation costs;

d) No sensitivity analysis has been included in the report, yet some parameters are subject to considerable uncertainty, such as the estimated long run marginal cost (**LRMC**) of new generation capacity of $75 per MWh; and

e) Excluding the dynamic efficiency losses (which are not applicable to options 3 to 5), Castalia find that TAs produce positive net benefits, in Auckland of $6m per annum and extrapolated across NZ of $15m per annum. Allowing for the additional benefits from deferral of easement costs, increases the benefits to $15m and $37.5m million respectively.

180. In regard to the CRA analysis of the net benefits of TAs, the Commission notes that

a) CRA assume that expenditure on resource consents and easements is sunk. However, it may be preferable for the Commission to apply the GIT prior to Transpower seeking approval for expenditure on easements and again prior to the need for construction of transmission lines. This means that TAs may avoid spending on easements as well as construction.

b) CRA did not include any avoided transmission operating and maintenance costs or the $65 million physical cost contingency.

c) CRA estimate significant unserved energy costs for coal fired plant (20% of deferral benefit) and combined cycle gas turbines (CCGT) (35% of deferral benefits). While these estimates may be reasonable, CRA do not explore combinations of generation, which will achieve higher levels of overall reliability.

d) CRA's analysis implies that if provided returns equal or exceed the weighted average cost of capital (WACC), investment will occur. However, in reality, firms will seek to maximise returns and may have other more attractive investment alternatives.

e) CRA's conclusion that some forms of generation appear viable at low WACCs, but that the majority are not viable at high WACCs, is consistent with the Commission's understanding that the amount of support required for generation TAs is likely to be small (and possibly zero) relative to cost. If no subsidy is required, the commitment problem may still need to be addressed by some form of TA enablement.

181. The Commission considers the asymmetric risks of too much versus too little capacity will be taken account in the GIT. Potential future redundancy of TA plant should be taken account of in the calculation of the cost of TAs.

182. The Commission accepts that TAs may provide additional security during construction of transmission lines.

4.5.4 Conclusions

183. The Commission considers that a cost benefit assessment is an important element in reaching a view on the appropriate means of enabling TAs. However, it remains of the view that a CBA should be completed following a decision on the high level approach to TAs and prior to any rule change (if required). This does not imply that the Commission will select an option in

advance of a full CBA. The rule change process requires the Commission to consider all reasonably practicable options, and the Commission is likely to consider a number of options for the rule change.

184. The Commission believes that the two reports quantifying some of the costs and benefits are helpful, but do not provide a full assessment of the net benefits of TAs. They do provide support for the view that the cost of TAs may be low relative to transmission investment and that there are potentially significant static efficiency benefits from TA procurement, but that care needs to be taken to manage dynamic efficiency risks.

4.6 Discussion regarding linkages with other work streams

4.6.1 Submissions

185. Several submitters noted a strong link with the choice of transmission pricing methodology, suggesting that:

a) decisions about a TA mechanism should not be made in isolation of decisions on the transmission pricing methodology as they are inextricably linked;

b) locational transmission pricing would address many of the issues that a TA regime has been proposed to address; and

c) there are some practical difficulties with implementing full locational pricing, but a TA procurement mechanism is also complex. Locational pricing should not therefore be decided against based on being too complex. A degree of locational pricing may be sufficient, e.g. new investment only, zonal interconnection basis, etc.

186. Several submitters noted strong linkages with part F processes involving the GIT and GUP, and suggested amendments to these processes:

a) Genesis suggested an alternative approach to the GIT process whereby Transpower can proceed with proposed grid investments to a specified stage, even if a lower cost TA is identified. The final commitment to construction of the transmission wires solution would only proceed if the TA failed to materialise; and

b) Meridian suggested amending the transmission approval process by staging it in two milestones (securing route, construction) to enable more time for market-based new investment and increase certainty for grid users.

187. Several parties noted linkages with the wholesale market issue of energy market pricing, specifically, the lack of VoLL pricing. One submitter recommended initiating a specific work stream (sitting across transmission, wholesale and security of supply work streams) tasked with developing a capacity mechanism.

188. Several parties noted linkages with work on Grid Reliability Standards.

189. Linkages with other Commission work streams noted by submitters included:

    a) Financial transmission rights; and

    b) Auckland transmission upgrade (Contact, who proposed that TAs should be used in that urgent upgrade situation as a means of emergency risk management, and Vector, who suggested that any TA regime should only be considered after the immediate security of supply situation in Auckland is addressed).

190. Several submitters noted that it is important to take the time to assess the combined effect of the many governance and regulatory arrangements that have been put in place, and ensure that a coherent market design results from work undertaken under different Commission work streams.

4.6.2 Discussion

191. The Commission accepts that it is desirable to consider grid upgrades in a two stage process, separating the securing of the route from construction, as discussed by submitters.

4.6.3 Conclusions

192. The Commission proposes to take account of the linkages with other work streams, by developing a work programme on market design. This will enable the Commission to take account of the linkages between TAs and other work areas.

4.7 Submissions regarding process

4.7.1 Submissions

193. MRP considered the consultation paper to be more of a draft issues paper than a draft decision paper. MRP believed that there should be a high standard of proof required before the Commission decides to intervene. MRP considered that the Commission should redevelop the problem definition, develop further options (enhanced market response and refined grid upgrade), narrow the definition of TAs, review international experience and undertake a quantitative CBA, and that this work should form the basis of a draft decision paper.

194. Genesis considered that the consultation paper requires a quantitative CBA, and that the analysis in the paper was not an adequate basis for taking a decision on TAs. It considered further work is required on defining TAs, non-funding barriers to TAs, the impact of TAs on the electricity market and a holistic consideration of the impact of other workstreams.

195. MEUG/NZIER note that the consultation paper was extremely detailed in some areas and appears to go beyond what might be expected in a consultation paper. They suggested that the Commission advance further consultation on TAs in two steps. First, publish a decision on which of the five

options is preferred, along with the rationale for them, and then publish another consultation paper on implementation options for the preferred option.

4.7.2 Discussion

196. The Commission has responded to the concerns in regard to the problem definition, options and cost benefit analysis elsewhere in this paper. The Commission appreciates that the complexity and importance of TAs and the diversity of views requires careful consideration. It agrees that implementation details are best considered following decisions on the high level issues, although the Commission notes that this is likely to involve the consideration of more than one option at the implementation stage.

4.8 Other issues

197. The Commission notes that since the publication of the consultation paper on the enablement of transmission alternatives, Transpower have issued a request for information (RFI) for alternatives to a transmission upgrade for Christchurch and the upper South Island. In the RFI, Transpower indicate that it proposes to include a RFI on alternatives as part of its transmission planning process following identification of transmission needs in the GRR. The RFI for the Christchurch/upper South Island upgrade closes on 16 February 2006. Transpower propose to consider submissions and issue a list of options and proposed timing by the end of July 2006.

198. On page 23 of the RFI noted above, Transpower notes that “Presuming fuel supply is reasonably guaranteed Transpower could contract with the generator when to operate at specific times of day in specific seasons. This would enable Transpower to have reasonable certainty that the peak demands could be met.” And also: “Similarly, demand side initiatives may provide savings….”. This and comments Transpower has made in this submission (as noted in Para 17 above) indicate that Transpower is prepared to contract with generation or load as a transmission alternative where this results in lower costs.

4.7.3 Conclusions

199. The Commission proposes to publish a Summary of Submissions and seek cross-submissions on the submissions received on the consultation paper. Following cross submissions and consultation, the Commission proposes to publish a draft decision paper in 2006 and a final decision paper later in the year. If a rule change is required to implement the high level decision, the Commission will develop and consult on a rule change following the final decision paper.

5. General conclusion

200. Overall, the Commission remains of the view there are significant barriers to the development of TAs under current regulatory arrangements and that the Commission’s evaluation criteria are broadly appropriate. It is still of the view

that free rider and commitment problems are significant barriers to investment in TAs, but accepts that some submitters have identified alternative responses to these problems. It accepts that management of dynamic efficiency/slippery slope risks are central to the development of efficient TA enablement.

201. The Commission's accepts that enhanced market design and particularly capacity pricing, as suggested by submitters, may effectively address barriers to the development of TAs. The Commission is developing a work programme to consider market design issues. Clearly, this work programme will have significance to issues beyond TAs, such as hedge market design and transmission pricing. It is not anticipated that this work would be complete before end of 2006 and implementation will take place in the following years.

202. However, the Commission considers that an interim solution may be required to address TAs for grid upgrade proposals over the next three to five years. At a high level, the Commission's preferred approach, if an interim solution is required, is some form of minimal central procurement. The details of this arrangement would be developed as part of any rule change process. The Commission considers that this option encompasses the NEM model of the grid owner acting as the procurer of TAs (suggested by a number of submitters) and that it also encompasses the procurement of TAs for emergency risk management and for managing uncertainty during construction.

203. The Commission considers that it is appropriate to consider the framework for the enablement of TAs following further progress in the consideration of the initial GUP to enable the Commission to take account of experience with the current framework for transmission procurement and transmission alternatives. .

204. The Commission proposes to consider the need for an interim solution, following cross submissions on this document and a final decision on the first GUP.

6. Questions for submissions

205. The Commission would like cross-submitters to consider the following questions:

Q1. Are there major arguments in any of the submissions that you disagree with? If so, can you please explain the reasons for your disagreement and a discussion of what your argument would imply for TAs?

Q2. Do you agree with the Commission's response to the submissions? If not, please explain which section you disagree with and why.

Appendix A: The Australian NEM model

Introduction

1. Several submitters have suggested that if central procurement of TAs is necessary then such procurement should be modelled on similar arrangements in the National Electricity Market in Australia. In particular the arrangements whereby the Transmission Network Service Provider (TNSP) considers TAs as part of any grid upgrade proposal under the regulatory investment test. For New Zealand this would be equivalent to Transpower, as Grid Owner, considering TAs as part of any GUP put forward under the GIT and acting as the procurement agent for TAs.

Purpose and structure

2. This appendix provides background information of arrangements for procurement of transmission alternatives in Australia.

Summary

3. The Australian arrangements for TA procurement are based on allowing the TNSP to make appropriate tradeoffs between grid investments and TAs. This is backed by a regime of incentives on the TNSP to minimise the cost of delivered transmission services and maximise the quality.

4. The key differences between the Australian arrangements for procurement of network support and the proposed NZ TA procurement options are:

   (a) Responsibility for application of GIT

   (b) Financial Risk for Grid Investment Decisions

   (c) Performance Incentive arrangements

5. Some submitters have also argued that timing of when TAs are considered is also different as the Australian TNSPs consider TAs as part of their application of the regulatory investment test. However there is nothing to prevent Transpower considering TAs in its own application of the GIT before submitting a GUP to the Commission under the NZ arrangements. For the Christchurch and upper South Island, Transpower have issued a request for information for alternatives to transmission investment to meet demand beyond 2012.

Australian approach

6. The Australian transmission regulatory arrangements place responsibility for decisions on grid investment or TA investment on the TNSP. This is balanced by a regime that encourages them to make efficient investment decisions by having quality incentives and cost minimisation incentives.

Regulatory regime

7. The overall transmission regulatory regime in Australia is aimed at providing the TNSP with appropriate incentives to invest to maintain adequate service standards but to also minimise the costs of investments and operating costs.

8. It achieves this by allowing the TNSP a degree of commercial freedom in making grid investment decisions but balancing this with a degree of commercial risk for making poor investment decisions.

Revenue cap

9. The TNSPs income is subject to a regulatory revenue cap. The cap is set every 5 years and based on the regulators assessment of the optimal asset base and a regulated rate of return on this asset base. Within this revenue cap the TNSP has incentives to minimise costs in order to maximise profits. To balance the cost minimisation incentive from the revenue cap a performance incentive is applied.

Performance incentives

10. To ensure the TNSP has adequate incentives to both operate and optimally invest in their network a performance incentive is applied. A basket of 5 performance measures, based loosely on system minutes of lost supply, is defined and performance standards set. Up to 1% of the revenue for each TNSP is at risk against these performance measures.

Regulatory investment test

11. Before a network investment can be included in the regulated asset base for consideration under the revenue cap it must be approved by the regulator (currently National Electricity Code Administrator (**NECA**) but moving to the Australian Energy Regulator (**AER**). To have the investment approved the TNSP must convince the regulator that:

    (a) The investment is necessary to meet its performance standards; and

    (b) It has considered all options and selected the least cost option.

12. The approval process includes consultation of all affected parties. This provides incentives for truthful revelation of information on costs.

Commercial risk

13. The TNSP also faces a degree of commercial risk over poor investment decisions. As part of the 5 yearly revenue cap setting exercise the regulator undertakes a review of the TNSP assets to see if they are optimal for the current system situation. Should the regulator consider a particular asset is unnecessary, or more than necessary then only the costs of an “optimal” investment will be included in the regulatory asset base used for setting the revenue cap. Thus if a TNSP over invests, or makes a bad investment

decision it faces a degree of asset stranding risk on these investment decisions. An example of this the Haymarket Substation upgrade in Sydney. Where the TNSP claimed costs of $300Million but the regulator only approved costs of $100M to be included in the regulatory asset base.

TA (network support) procurement regime

14. This section summarises the Australian network support procurement regime.

TNSP contracts for network support

15. If a TNSP decides a generator or demand-side option is lower cost than a transmission investment option for a particular grid congestion problem it may enter into a network support contract with the relevant generator or demand-side participant. Network support is the equivalent of a TA procurement contract in NZ.

16. The TNSP would pay the generator or demand-side participant for provision of energy (or load reduction) at key times to protect against transmission security events, such as a contingent event. Typically these arrangements would be peaking contracts. At the time the generator is providing network support it must offer into the market at its marginal cost. It receives financial compensation for such lost profit opportunities from the TNSP.

17. The network support contract covers such issues as guaranteed availability, performance etc and the required cost / reliability trade offs are made by the TNSP in negotiating the contract. It has incentives to ensure the contract meets appropriate performance incentives because of its own performance incentives. It has incentives to minimise costs because of the risk of not having the costs approved, or having them optimised out later, in the regulatory asset base review process.

Decision on network support (TA) procurement

18. The key point with TA procurement regime in Australia is that it is the grid owner (TNSP) who is responsible for identifying any transmission alternatives and determining if they are lower cost than the proposed grid investment. At the stage of approval of a grid (or TA) investment the regulator's role is limited to determining the basis for the grid investment planning process, ensuring adequate consultation on the proposal is carried out, and approving or declining an investment. It has no role directing the TNSP what TAs it should consider in any investment decision process and as such no obvious mechanism exists for avoiding the inherent conflict of interest when TNSP's consider the merits of contracting to use alternatives rather than constructing grid assets.

Commercial risk on network support (TA) procurement

19. The above commercial decision making freedom of the TNSPs is balanced by a degree of risk for their investment decisions. The regulator gets a second

bite at the apple by being able to "optimise out" of the regulatory asset base any grid investment (or TA contract) they retrospectively decide is not optimal. This happens during the 5 yearly review of the revenue cap. Therefore, the TNSP faces a degree of commercial risk in any network support contract they enter.

Operating arrangements

20. Once contracted by the TNSP the network support generator comes under the operational control of the system operator. The network support contract requires them to offer their resource (generation) at marginal cost when called upon to do so by the system operator, i.e. when there is a short term forecast shortfall in the region. Their offer is not considered in setting the market price. The degree of financial compensation they receive from the TNSP network support contract effectively includes a forward estimate of the lost opportunity cost of not being able to exercise market power to obtain maximum electricity price at this time. The operating arrangements may allow the grid owner to pass the risk of non-performance to the TA provider.

Example

21. The overall Australian experience with the use of transmission alternatives to delay or minimise the extent of grid upgrade work appears to have been positive. In the case of the Powerlink upgrade of the central to northern Queensland link, a local Gas Turbine generator has been contracted to provide local peaking support and enable the delay of the transmission upgrade by approximately 2 years. This appears to be a win / win situation in that those paying for the upgrade can have confidence that the minimum cost option has been chosen and Powerlink can have confidence that the commercial risks of not recovering their investment are minimised.

Appendix B: Summary of submissions on 'Options for Enabling Transmission Alternatives' consultation paper

The following is a summary of submissions broken down by submitter with brief summations of their treatment of eight key issues that were raised. The eight key issues are: Problem Definition; Evaluation Criteria; Economic and Regulatory Arguments (Investment Certainty, Transmission – Free Rider Issue, Nodal Pricing – Free Rider and Deficiency Issues and Dynamic Efficiency / Slippery Slope Issue); Assessment/Preferred Option; Other Options; Cost-Benefit Analysis issues; Linkages with Other Work Streams; and Process.

Key Issue: ***Problem Definition***

Key Issue	Comment (paraphrased)	Response
Transpower	Transpower disagrees with proposed problem definition. Transpower considers there has not been a market failure in terms of generation locational investment decisions. They consider the market failure is in transmission investment. They do not accept that free rider problems have led to fewer than optimal TAs emerging in the past. Points to generator locational investment decisions and existing TAs as evidence of TAs emerging without need for regulatory intervention. It does not directly oppose the commitment problem but considers the Commission's proposed solution would aggravate this problem by delaying TA contracting until after GIT process finished. Proposes an alternative solution which addresses this by having Grid Owner include consideration of TAs within GUP and if necessary contract with them. It considers that the transmission section of the industry is a natural monopoly and role of regulator is to ensure efficient transmission	Responses to the points made here are included in the problem definition section of the Submissions Summary Paper.

Key Issue	Comment (paraphrased)	Response
	investment decisions. The regulator should not be involved in the generation section of the market. Express concern that proposed TA arrangements will lead to indirect Commission intervention in market processes for generator investment, eroding dynamic efficiency of this market process. Its preferred option is to add minor improvements to the current market processes to improve generation and demand-side market investment decisions, and suggests a range of possible measures to improve the market (as below).	
Genesis Power	Genesis disagrees with the Commission's problem definition. Genesis considers there is not a free rider problem with the broad definition of transmission alternatives adopted by the Commission, i.e. there is no free rider problem for generation investments. It accepts there are free rider problems with a narrow subset of transmission alternatives that supply only transmission services, not energy services. Genesis considers the commitment problem is wrongly stated, and that the GIT and GUP processes, if properly applied, will provide investors sufficient certainty to proceed with economically efficient (no free riding) investments without risk of subsequent stranding by a regulated transmission investment. It considers the commitment problem for generation investments is more to do with other uncertainties, such as resource consents, land, and fuel supply uncertainty, than funding issues.	Responses to the points made here are included in the problem definition section of the Submissions Summary Paper.

Key Issue	Comment (paraphrased)	Response
	Genesis is deeply concerned that any move to regulate procurement arrangements for transmission alternatives, if it involves generation investment subsidies, will erode the dynamic efficiency advantages of market-based generation investment decision processes.	
Contact Energy	Contact broadly agrees with the problem definition. It notes that some free rider issues exist as a result of the grid owner not being able to selectively disconnect customers at times of shortage. Contact considers that there are some informational and political impediments that prevent generators developing offer strategies that address the nodal pricing free rider problem. It also considers that postage stamp transmission pricing and anytime-maximum demand rather than coincident peak demand pricing distort decision-making.	Responses to the points made here are included in the problem definition section of the Submissions Summary Paper.
Meridian Energy	Meridian strongly disagrees with the problem definition. Meridian disagrees with the premise that some TAs may not have emerged due to free rider and commitment problems. It notes that most recent significant generation investments have occurred in the upper North Island, and suggests that it is not clear that regulatory processes would have delivered different/lower cost outcomes. The appended report from CRA suggests that potential TAs are already commercially viable or nearly so, particularly generation TAs. Meridian disagrees with the inference that TAs are direct substitutes for transmission, and suggests TAs should be considered complementary to transmission investments.	Responses to the points made here are included in the problem definition section of the Submissions Summary Paper.

Key Issue	Comment (paraphrased)	Response
	Regarding the stated commitment problem, Meridian suggests that it is incorrect to state that transmission can strand generation investments.	
Mighty River Power (MRP)	MRP considers that the consultation paper does not adequately demonstrate that there is a problem that needs to be solved or that there are real barriers to transmission investment. MRP lists further examples of TAs that have occurred but were not listed in the paper. MRP considers that the commitment and free rider problems are not market failures but problems arising from the EC's approach to the GIT and transmission pricing. Further, these problems are only some of many factors that impact on the commercial viability of TAs. The paper does not provide evidence or examples of where TAs investment has not occurred but that would have been more efficient than upgrading transmission. The paper does not indicate the scale of the problems and the extent to which they would be a barrier in the future. MRP commissioned a report from NERA. NERA note that: • Optimal investment in the electricity sector requires optimal trade offs between transmission, generation and demand side; • Generation and demand can sometimes be substitutes and sometimes complements to transmission investment. The Commission should have recognised this in the Consultation Paper; • The lumpy nature of grid upgrades means that it can be worthwhile to delay transmission investment, particularly in the early years; • Achieving the optimal solution is likely to require both administrative processes and decentralised decision making. NERA identify potential barriers to optimal investment under current arrangements as: • NERA note that	Responses to the points made here are included in the problem definition section of the Submissions Summary Paper.

Key Issue	Comment (paraphrased)	Response
	1. Transpower is unlikely to possess best information on local power needs and potential least-cost solutions in a given supply area; 2. There are legal barriers to Transpower recovering TA costs; 3. Transpower may have incentives to prefer solutions it can control (transmission) over contracting with third parties for TAs, particularly given it is not clear how the Commerce Commission's threshold control regime would accommodate such risks; and 4. There may be a cultural issue, such that Transpower prefers lines-based solutions to less concrete alternatives such as TAs. • NERA consider that the sequencing of the GIT discourages Transpower from considering TAs as part of the GUP. • NERA note the possibility of implementing locational transmission pricing and state that it is unclear yet as to whether transmission pricing will be capable of sending the correct price signals. • NERA note that a number of TAs have developed in spite of free rider issues. It argues that demand-side participants have incentives to reduce demand, despite not capturing the price reduction benefits, due to the reduction in consumption.	
Trustpower	Trustpower agrees with the Commission's problem definition but thinks it needs to be expanded to include: • How can the Commission ensure that economically efficient TAs can develop and receive sufficient economic benefit to ensure they are developed? • Is it necessary to provide regulated funding for TAs and, if so, in what form?	The Commission considers both questions are already captured within the free rider aspect of its problem definition, i.e. if there is no free rider problem then the economically efficient TA would develop without the need for funding.

Key Issue	Comment (paraphrased)	Response
Orion	Orion generally agrees with the Commission's problem definition, making the following comments: • More attention should be paid to reaching efficient investment solutions involving combinations of TAs and grid investment; • It believes the 'slippery slope' issue is overstated (see comments in the section on 'Slippery Slope Issues'); • More attention should be paid to cheap demand-side alternatives, and to the existing incentives for some participants to encourage/discourage TAs; • Consideration needs to be given to the problem that demand-side initiatives would often be developed under short-term relationships, which undermines the medium- and long-term feasibility of such TAs.	These comments are addressed in the problem definition and Options sections of the Submissions Summary Paper.
Vector	Vector's submission is principally concerned with the immediate grid upgrade required to ensure N-1 security into the Auckland region. It suggests that N-2 security is more appropriate for the region.	Noted.
WEL Networks (WEL)	WEL submits that the definition of network TAs set out in the consultation paper is too narrow. It suggests that the definition be widened to include low voltage lines as network TAs when they: • Transfer load for congested to non-congested lines; and • Enable the System Operator to better optimise the network.	Noted. This is an implementation issue, which will be considered when the rule change is developed.
Electricity Networks Association (ENA)	ENA disagree with the problem as asserted in the consultation paper. ENA submits that sub-optimal investment in TAs has occurred because of institutional barriers. Specifically, the transmission pricing methodology (TPM) and the overall impact of the Electricity Industry Reform Act 1998 (EIRA). ENA believes that if these barriers did not exist, a number of generation projects would be very likely to be	Noted. This comment is discussed in the Options section of the Submissions Summary Paper.

Key Issue	Comment (paraphrased)	Response
	developed by lines companies where generator/retailers may not be interested or may not see the required rate of return.	
Energy Efficiency and Conservation Authority (EECA)	EECA agrees with the Commission's assessment that there has been sub-optimal investment in TAs in the past, and agrees that procurement is a way of encouraging investment.	Noted.
Solid Energy New Zealand (SENZ)	SENZ agrees with the Commission's problem definition but adds that, "historical investment has been relatively efficient for the policy and regulatory settings at the time of those investments." SENZ agrees with the Commission's assessment that there are significant free rider and nodal pricing problems with TAs.	Noted.
Major Electricity Users' Group) (MEUG) / New Zealand Institute of Economic Research (NZIER)	NZIER (on behalf of MEUG) broadly agrees with the Commission's problem definition, but disputes the certainty that the consultation paper gives to transmission upgrades approved via the GIT (this is explained further and responded to in the investment certainty section).	Noted.
New Zealand Council for infrastructure Development (NZCID)	NZCID's main focus is on the promotion of immediate investment in grid upgrades. NZCID submits that in respect to the Auckland and Upper South Island proposed transmission upgrades, the potential time for planning and implementation of TAs has lapsed. NZCID identifies the high capital costs and time consuming consenting process in the energy market as significant barriers to market entry and	Noted.

Key Issue	Comment (paraphrased)	Response
	competition. Furthermore, NZCID states that failure to upgrade the grid will cause localised monopolies that would directly contradict the Commissions objective of ensuring long-term benefits to end users.	
Comalco	Comalco submits that investment in alternatives have been sub-optimal not for the reasons outlined by the Commission, but rather because of: • Concerns over gas supplies; • Uncertainty over government policy on carbon taxation; • The RMA process deterring generation from renewables; and • Inefficient markets that do not enable significant demand-side response.	The Commission agrees that there are other reasons than just free rider and commitment issues for sub-optimal investment.
Green Zephyr	Green Zephyr submits that, "[h]aving seen Transpower's base measurements and predictions; uncontrolled peak load is as much an issue as daily capacity." It agrees with the need for TAs, noting that, "too much has been made of removing the [capacity] limit and not enough has been done to live within it." Green Zephyr would like to see a focus placed on a more efficient and responsible future direction for the industry.	Noted.
Brian Tolley	Mr Tolley submits that there has been market failure. He suggests that many of the present problems stem from the structure of the industry, relationships, statements of corporate intent, and lack of decision and direction.	Noted.

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Key Issue	Comment (paraphrased)	Response
Brian Leyland	Mr Leyland submits that if we accept that TAs are needed then the market has failed to provide sufficient investment. I.e. the market does not sufficiently reward those who hold reserve capacity or build power stations where they are needed (from a transmission perspective).	Noted.

Key Issue: ***Evaluation Criteria***

Submitter	Comment (paraphrased)	Response
Transpower	Disagrees with proposed Evaluation Criteria. Transpower proposes that the level-playing field criterion be deleted, as it considers that because transmission is regulated and TAs are part of the competitive market it is not appropriate to aim for a level-playing field. It considers that several other criteria should be added: ▪ "Is of national benefit to New Zealand", i.e. a wider test than net industry benefit as included in the GIT; ▪ "Is a consistent component of an overall integrated market and regulatory design"; ▪ The level of assurance that grid reliability standards will be met. This addresses the concern that TAs may not be as reliable as wires investments; and ▪ Subjects electricity costs and prices to sustained downward pressure. Transpower also considers that such a major policy change should be the subject of a rigorous cost-benefit analysis and not just as assessment against a set of criteria.	These comments are discussed in the Evaluation Criteria section of the Submissions Summary paper.
Genesis Power	Genesis disagrees with the approach of using selection criteria rather than a cost benefit analysis that includes allocative, productive and dynamic efficiency assessments for each option.	Noted.
Contact	Contact accepts the Commission's Evaluation Criteria. However, it has developed different weightings.	Noted.

Submitter	Comment (paraphrased)	Response
Meridian Energy	Meridian disagrees with the evaluation criteria, weightings and scorings. It notes that the emphasis of the criteria conflicts with central economic efficiency themes set out in the Electricity Act, GPS, and GIT. Suggests that criteria should more transparently reflect Act/GIT objectives and focus on the problem that the regulation is seeking to address. Materiality of benefits should be more prominently considered, and it should be clearer how qualitative benefits of transmission investment (e.g. supporting national market) are included in the evaluation process.	The Commission notes that these comments are discussed in the Evaluation Criteria section of the Submissions Summary paper.
Mighty River Power	MRP does not agree with the Commission's evaluation criteria or weightings. It considers that the criteria confuse "means" with "ends". For example, 'level playing field for transmission and TAs' is a means for minimising the cost of electricity supply. MRP consider evaluation criteria should be driven off the EC's principle objectives.	The Commission notes that these comments are discussed in the Evaluation Criteria section of the Submissions Summary paper.
Trustpower	Trustpower agrees with the criteria but disagrees with the Commissions assessment against the criteria. This is discussed further by Trustpower under Assessment of Options.	Noted.
Orion	Orion agrees that tables 1 & 2 reflect the criteria set forth by the Commission, but believe that such qualitative measures are too subjective. It would prefer to see a CBA to "provide an accurate assessment of the relative merits of each option". Orion emphasises that it sees demand-side management and local generation as being complementary to transmission, both assisting to defer grid investment through the management of peak transmission capacity and also in managing uncertainty.	Noted.

Submitter	Comment (paraphrased)	Response
EECA	EECA agrees with the evaluation criteria in the consultation paper but submits that the Commission's and EECA's objectives with regard to demand-side management, electricity efficiency and renewable energy should be included.	The Commission included an assessment of the proposals against its objectives in the consultation paper. However, these criteria are not sufficiently detailed for evaluation of TA options.
SENZ	SENZ submits that the Commission should consider, in assessment, a 'fatal flaw' approach that scores an option significantly negative if it has a serious flaw.	Noted.
NZIER	NZIER propose that the Commission's evaluation criteria be replaced with the following Evaluation Criteria, with extra weighting placed on the first two points: • Promote a level-playing field between grid investments and transmission alternatives, and between alternative types of transmission alternatives, so that the option ranked highest under the grid investment test consistent with the grid reliability standards is chosen; • Provide reasonable certainty that the optimal investments in the grid or in transmission alternatives will occur within required timeframes, and the services will be provided when required; and • Ensure that the investment decision-making process for transmission does not adversely impact on the dynamic or static efficiency of markets for electricity. They consider the Commission's assessment, that TAs occur where they are lower cost than transmission, is too restrictive. NZIER note that the evaluation criteria does not allow for any consideration of price-quality trade offs.	The Commission notes that these comments are discussed in the Evaluation Criteria section of the Submissions Summary paper.

Submitter	Comment (paraphrased)	Response
Comalco	Comalco disagrees with the evaluation criteria and weighting proposed in the consultation paper. It notes the following: • The focus should be on maximising the dynamic efficiency of investing in TAs and transmission assets; • It, therefore, follows that creating a level-playing field is a relevant criterion; • Promoting certainty of investment is a relevant criterion; • Maximising innovation and promoting TA investment are not relevant criteria All remaining criteria are reasonable.	The Commission notes that these comments are discussed in the Evaluation Criteria section of the Submissions Summary paper.
Sustainable Energy Forum (SEF)	SEF strongly disagrees with the evaluation criteria in the consultation paper. SEF believes that the criteria are an "entirely inappropriate" narrowing of the GPS and Electricity Amendment Act (2004). SEF posits that more accurate criteria would give a significantly larger weighting to environmental sustainability and efficiency.	See comment above under EECA.
Brian Leyland	Mr Leyland posits that each option should be tested against: • Its ability to overcome the defined problem; • The likely effect on prices; • The effect on the market; and • How easy it would be for market participants to game the market. Mr Leyland suggests that there are competition benefits from having a centrally co-ordinated transmission system. He raises the question of gaming issues with particular reference to: • Asymmetries in information that will allow the candidate for a TA to overstate their need for assistance; and • Gaming in respect to bidding up nodal prices using other stations at	Noted, see discussion in the 'Slippery Slope' section of the Submission Summary paper.

Submitter	Comment (paraphrased)	Response
	a node.	

Key Issue: ***Investment Certainty***

Submitter	Comment (paraphrased)	Response
Transpower	Transpower disagrees with the Commission's view of investment certainty and regulatory commitment issues. It considers that the key issue for investment certainty is investors' certainty of regulatory action, i.e. that the regulator will not interfere with the investment process through regulatory action. On the specific issue of the Commission's certainty that a TA will emerge if selected, Transpower agrees that the EC would need a high degree of certainty that a TA will emerge before rejecting a GUP transmission proposal.	See section of Submissions Summary Paper on Investment Certainty issue.
Genesis Power	Genesis disagrees with the Commissions assessment of investment certainty and commitment issues. It considers investment certainty would not be an issue if TAs were carefully defined. Consideration of the alternatives could be part of the GUP process. It suggests that under such an approach, the investment certainty problem largely disappears.	See section of Submissions Summary Paper on Investment Certainty issue and assessment of options.
Contact Energy	Contact submits that improvements in market design should be used to address the commitment issue.	See section of Submissions Summary Paper on Investment Certainty issue and assessment of options.
Meridian Energy	Meridian notes that in Australia's National Electricity Market (NEM), the Regulatory Test was recently amended so that only committed TAs with proponents are considered. The term "committed" requires that all required consents & licences have been gained, there is a firm construction commencement date, and contracts for major plant	See section of Submissions Summary Paper on Investment Certainty issue and assessment of options.

Submitter	Comment (paraphrased)	Response
	components and finance are both in place. Suggests that the GIT should not be conducted on a conceptual or generic TA for this reason, and also because each TA has different characteristics. Also notes concern that emphasis on TAs runs the risk of creating uncertainty in the transmission investment process, though transmission investment is urgently required.	
Mighty River Power	MRP does not agree with the Commission's assessment of investment certainty and regulatory commitment. It supports the statement in the consultation paper that the repeated nature of GITs will reduce or eliminate commitment problems over time.	Noted.
Trustpower	Trustpower agrees with the Commission's assessment.	Noted.
Orion	Orion agrees with the assessment of the issue of investment certainty in the consultation paper, but note that locational pricing could reduce the risks of investment uncertainty.	Noted.
Vector	Vector agrees with the Commissions assessment of the commitment problem.	Noted.
MEUG/NZIER	MEUG/NZIER note that Transpower currently has no legal requirement to implement an approved GUP, thus it questions the high level of certainty of transmission investments assumed in the consultation paper. NZIER posits that such a situation could occur because of: • Alterations the Commission imposes on a GUP; • Approval of only part of a highly inter-related (and contingent) set of	The Commission notes this point and accepts that the approval of the GUP does not imply absolute certainty, but notes that the relevant question is the comparable level of certainty between TAs and transmission investment.

Submitter	Comment (paraphrased)	Response
	GUPs; and • The restricted ability of Transpower to recover costs of investments through the price-path threshold regime.	

Key Issue: ***Transmission – free rider issue***

Submitter	Comment (paraphrased)	Response
Transpower	Transpower broadly agrees with the Commission's assessment of free rider issues on transmission pricing but notes some significant issues in designing a locational transmission pricing mechanism.	Noted.
Genesis Power	Genesis considers the free rider problem is not significant for investments that participate in the energy market. It is only applicable to a narrower set of TAs that solely provide transmission services.	See section in Submissions Summary paper on the transmission free rider problem.
Contact Energy	Contact agrees that the free rider problem undermines incentives to invest in TAs. It notes that if location-based charges levied at long-run marginal cost (LRMC) of grid expansion were adopted then the free rider problem would not exist, but that such charges can be difficult to implement and may have perverse effects (charges would reduce following grid upgrade). Contact notes that alternative forms of location-based charging (such as charging users once upgrade has occurred) will also suffer from the free rider problem.	See section in Submissions Summary paper on the transmission free rider problem.
Meridian Energy	Meridian disagrees with the Commission's assessment of free rider problems in regard to transmission charges. It notes that transmission charges are a lower order consideration in investment decisions. It suggests that it is not clear that the extent of the free rider problem is sufficient to merit proposed intervention.	See section in Submissions Summary paper on the transmission free rider problem.
Mighty River Power	MRP does not agree with the Commission's assessment of transmission free rider issues. MRP does not think that the free rider issue will 'make or break' investment decisions, and notes that a number of TAs have occurred in the past.	See section in Submissions Summary paper on the transmission free rider problem. In regard to the energy efficient

Submitter	Comment (paraphrased)	Response
	In regard to the example in the consultation paper of a manufacturer considering an energy efficiency investment, but who is unable to capture the full benefit of reduced electricity prices, MRP notes that the manufacturer would benefit from the drop in electricity consumption and the reduction in price. It considers the practical ability of any one user to reduce prices (except users like Comalco) to be nil. It also considers that this example is inconsistent with the consultation paper on demand-side bidding and forecasting, which claims that participants responding individually would collectively result in an excessive response.	manufacturer, the Commission notes that the key point is that the manufacturer cannot capture all the gains from their investment and therefore investment will not be optimal.
Trustpower	Trustpower agrees with the Commission's assessment.	Noted.
Orion	Orion agrees with the Commission's assessment of this issue and again notes that locational pricing would reduce the impact of this problem.	Noted.
WEL	WEL believes the Commission overstates this problem. It submits that the Commission should not attempt to eliminate the free rider problem as: • Determining free riders interferes in the market and requires the second guessing of investment decisions; • Investments not determined as being free riders are likely to be companies that have simply distorted financials to receive funding; and • There appears to be a complete lack of TAs, so the number of free riders would be small in practice.	The Commission does not agree and notes that the free rider problem impairs the development of cost-effective TAs. Gaming issues with regard to procurement of TAs are discussed in the paper, in the 'Slippery Slope' section.
SENZ	SENZ agrees with the Commissions assessment of this free rider issue and identifies TPM as a means by which this issue can be addressed.	Transmission pricing is discussed in links to other work streams.
MEUG/NZIER	MEUG/NZIER agree with the Commissions assessment.	Noted.

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Submitter	Comment (paraphrased)	Response
Comalco	Comalco agrees with the Commission's assessment and notes that it is an "extremely important" issue.	Noted.
SEF	SEF agrees this problem exists. It gives the Auckland transmission upgrade as an example, as it believes that locational pricing would naturally promote TAs.	Noted.

Key Issue: *Nodal Pricing – free riding and deficiency issues*

Submitter	Comment (paraphrased)	Response
Transpower	Transpower does not agree that free riding on nodal price is a significant issue for demand-side TAs. It also considers that, to the extent that this problem might exist, it is better addressed through separate demand-side initiatives such as the demand-side bidding forecasting (DSBF) project.	The Commission does not believe that the DSBF project will address free rider issues.
Genesis Power	Genesis considers free rider problems on nodal pricing are unlikely to be a significant problem delaying non-grid investment.	Noted.
Contact Energy	Contact agrees with the Commission's assessment, except with regard to a generator's ability to use offer strategy to avoid the free rider problem. It considers lack of VoLL pricing significantly contributes to lack of TA investment.	Noted. This is discussed in the Other Options section of the Submissions Summary Paper.
Meridian Energy	Meridian disagrees with the Commission's assessment of free rider problems in regard to nodal pricing, as it suggests that the change in nodal prices following investment is not generally substantial and is outweighed by additional revenue received for the capacity at the average national price. It suggests this is, at best, a second order consideration. Meridian generally agrees with the assessment of nodal pricing deficiency issues, except to note that the concern for vertically integrated generators is nodal price variation (para. 196) rather than price.	Noted.
Mighty River Power	MRP does not consider that free riding problems exist with respect to nodal pricing. It agrees that generators can avoid a collapse in nodal	Noted. This is discussed in the Other Options section of the Submission

Submitter	Comment (paraphrased)	Response
	prices through their offer strategy. It reiterates its point (discussed in the previous section) regarding the risks of an excessive demand-side response in the demand-side bidding and forecasting paper. MRP agrees with the Commission's views that deficiencies in nodal pricing do not in themselves justify regulated procurement. NERA (on behalf of MRP) criticise the free rider nodal price test for the lack of detail on how the test will work. They also claim that ordinary plant (as opposed to TA plant) would be unable to set prices, as it would be constrained by other generators. NERA further question whether the procurement process would result in profits from TAs exercising market power being bid away and suggest that the Commission has not considered the impact of the high nodal prices in constrained regions on purchasers of electricity. NERA outline three potential options to address higher prices in constrained regions: • No regulation of TA prices (called the laissez-faire option); • Constraining TA prices during TA periods; and • Constructing new transmission lines. NERA note that all options will affect market prices and that it is not obvious which is the least distortionary. They claim that dispatch will not be efficient if market power is exercised, as may occur under the laissez-faire option. NERA reject the risk of below-cost dispatch under the second option, on the basis that the TA contract would provide compensation, if the TA were required to run at a loss.	Summary Paper. The Commission notes the comment from NERA. It observes that ordinary plant like TA plant may be able to set prices in constrained regions, during times of a constraint. The comment on below-cost dispatch ignores the point that despatch may occur below a plant's marginal cost and thereby reduce efficiency. It's irrelevant that a plant receives compensation for this loss.
Trustpower	Trustpower disagrees with the Commission's assessment as it considers nodal prices will generally collapse when a generator invests in a	Noted. See discussion on nodal pricing in Submissions Summary

Submitter	Comment (paraphrased)	Response
	constrained region.	paper.
Orion	Orion submits that the free rider problem in regard to nodal pricing is a problem for the market response option. In regard to nodal pricing deficiencies, Orion submits that these issues exist but are secondary because treatment by a central means will be inefficient.	Noted.
WEL	See WEL's comments in section on Transmission Free rider issues.	
ENA	ENA submits that nodal pricing is deficient in that it discourages investment in TAs as, "a relatively small increment of local generation will mean a collapse in nodal pricing."	Noted, see discussion on nodal pricing in Submission summary paper.
SENZ	SENZ agrees with the Commission's assessment of the nodal pricing free rider problem. It suggests that this problem impacts particularly on large-scale and "must-run" generation TAs.	Noted.
MEUG/NZIER	MEUG/NZIER agree with the Commissions assessment.	Noted.
Comalco	Comalco submits that generation TAs do not suffer from this free rider problem as the procurement of TAs will capture high nodal prices as a region becomes constrained. However, demand-side TAs will be prone to this free rider problem.	Noted.
Norske Skog	Norske Skog agrees with the Commissions assessment of the nodal pricing deficiency issue.	Noted.
Green Zephyr	Green Zephyr identifies that the under-valuing of electricity is causing wastage and that price volatility acts as a disincentive to investment.	Noted.

Key Issue: ***Dynamic efficiency / slippery slope issue***

Submitter	Comment (paraphrased)	Response
Transpower	Transpower disagrees with the Commission's assessment of 'slippery slope' issues as it thinks the Commission has underestimated the difficulty in managing these issues even with the minimal central procurement approach. Information asymmetry would make it difficult for the Commission to perfectly manage the issues, and the risks to the dynamic efficiency of the market-driven generation investment process are huge.	Noted. Discussed in the Options and Slippery Slope section of the Submissions Summary Paper.
Genesis Power	Genesis is very concerned about dynamic efficiency / 'slippery slope' aspects of any TA procurement arrangement. It considers the best way to contain such problems is to clearly define transmission alternatives to be investments that only provide equivalent services to transmission. To the extent that such investments might also provide energy, they should be ring-fenced and required to offer any energy into the energy market at $0.	Noted.
Contact Energy	Contact considers that the consultation paper addresses most of the 'slippery slope' concerns. Its main concerns are around the central procurement (CP) mechanism: • Central procurement will distort price signals in the market, as only a subset of participants will receive contracts for providing capacity, but all plants contribute capacity. Increasingly, plants will only be procured by the central procurement process; • Central procurement will restrict opportunities to capture synergies from operating in energy market and providing dry year reserve. It does not believe competitive tendering will enable synergies to be captured; • Central procurement mechanisms are exposed to significant risks of	Noted, discussed in the options and slippery slope section of the Submission Summary Paper.

Submitter	Comment (paraphrased)	Response
	gaming due to information asymmetries between regulator and sponsor of project.	
Meridian Energy	Meridian believes that 'slippery slope' risks are not given adequate consideration in the analysis. To intervene in the competitive market, the materiality of the underlying problem must be unambiguously established, and intervention must not impact on competitive market's price outcomes. The potential consequences of intervention in competitive markets are significantly negative. Meridian also expresses concern that the longitudinal nature of the NZ power system means that the scope of generation that potentially fits under the TA definition is wide. In addition, the ability of a regulator to put in place checks and balances to manage 'slippery slope' risks suffers from information asymmetry problems.	See comments in the Options and slippery slope section of the Submission Summary Paper.
Mighty River Power	MRP considers that the consultation paper understates 'slippery slope' risks. It believes it would be difficult to distinguish between genuine TAs (that require assistance) and other potential TAs (which would have occurred in any case). MRP considers that dynamic efficiency should be given greater weight than static efficiency. NERA identify a number of efficiency issues: • The procurement agency may procure TAs that would have occurred anyway and this may distort competition; • The procurement agency may procure too much or too little TAs due to political pressure; • Providing out-of-market payments to new generators, as opposed to locational market energy prices that signal the higher value of capacity in a constrained area, reduces productive efficiency since cheaper external generation cannot be substituted for expensive	See comments in the Options and Slippery Slope section of the Submissions Summary Paper.

Submitter	Comment (paraphrased)	Response
	local generation. Further, procurement of TAs will create ongoing perverse incentives for generation and load when making location decisions. NERA suggest that procurement of TAs will increase regulatory uncertainty by harming the potential returns of investors who are not subsidised. They claim that the Commission's argument that the GIT will take account of sunk investment is too optimistic and that political pressure may distort decision-making. Under the decentralised procurement (DP) options, Transpower would decide whether to invest in TAs or transmission, and NERA do not believe that this is appropriate.	
Trustpower	Trustpower agrees with the Commission's assessment but considers the problem is not as serious as some proponents suggest.	Noted.
Orion	Orion conjectures that inevitably there will be some regulatory influence in the generation market as a result of centralised decision-making, but this intervention will alter the market to a lesser degree than the extremes suggested in the consultation paper. Moreover, this intervention is required to attain efficiency when market failure exists. Because of this, Orion would like to see the weighting of the 'slippery slope' issues decreased.	Noted.
EECA	EECA recognises that this is a problem. As a result, it states a preference for the limited DP option.	Noted.
SENZ	SENZ agrees with the Commission's assessment of the slippery slope risks. It asserts that these risks are manageable under the minimum CP option but are more serious under a DP scheme.	Noted.

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Submitter	Comment (paraphrased)	Response
Comalco	Comalco agrees with the Commission's treatment of the 'slippery slope' issue.	Noted.
Norske Skog	Norske Skog agrees with the Commissions treatment of the dynamic efficiency issue.	Noted.
Brian Leyland	Mr Leyland disagrees with the consultation paper's treatment of 'slippery slope' issues. To accompany the Commissions treatment of the issues, Mr Leyland would like to see a quantification of the 'slippery slope' loses, as observed in the market through the construction of the Whirinaki plant.	Quantification of the 'slippery slope' issues will be considered as part of the CBA, to be undertaken as part of the rule change process.

Key Issue: *Assessment / Preferred option*

Submitter	Comment (paraphrased)	Response
Transpower	Transpower's preferred option is an enhanced status quo (i.e. the enhanced market response option) with the suggested market design enhancements as noted above. Its second preference is for limited CP, where the grid owner, as part of the GUP process, undertakes procurement. However, it notes that even this approach risks the slippery slope of increasing regulatory intervention in market processes.	See discussion of this in the Options section of the Submissions Summary Paper.
Genesis Power	Genesis's preference is option 1 (market response). Some enhancements to transmission pricing could also be considered (Genesis noted the free rider issues with postage stamp transmission pricing but did not consider this was a major issue). Its second, less preferred, option is to consider arrangements similar to those used in Australia's NEM, whereby procurement is undertaken by the grid owner as part of the grid upgrade process. Genesis also provides an analysis using the criteria provided to show how its different assessment of the level of free rider risks and level of dynamic efficiency risks of any regulatory intervention could lead to a markedly different scoring result.	See discussion of this in the Options section of the Submissions Summary Paper.
Contact Energy	Contact prefers limited DP, followed by regional capacity constraints (RCC). It considers that minimal CP should be considered only as an emergency risk management mechanism.	Noted.

Submitter	Comment (paraphrased)	Response
Meridian Energy	Meridian prefers option 1 (market response), together with some enhancements to current processes (see 'Other Options'). It opposes procurement options. To even consider implementing a regulated procurement mechanism, Meridian believes it must first be determined that there are sufficient TAs that generate materially greater positive net benefits than the transmission option, and which would not otherwise be developed. Meridian does not believe there are sufficient generation TAs to pass this test, and this assertion is backed up by the CRA report it commissioned on the viability of TAs for the Auckland situation.[21] Meridian notes a number of practical implementation issues, particularly with DP options. These include how quantities are determined without making assumptions on transmission investment, practical issues relating to data and processes, verification, integration into the dispatch process, and contract/counterparty issues. Meridian notes that Universal CP has substantial slippery slope implications, but that minimal CP has fewer slippery slope implications if only demand-side is eligible. It believes that all procurement options will affect market price outcomes.	See discussion of this in the Options section of the Submissions Summary Paper.
Mighty River Power	MRP prefers Option 1, with consideration of other options (see Other Options section) if the Commission requires further consideration of regulated procurement. NERA argue that options 2 to 5 only address the barriers to optimal investment to a limited extent. CP options do not address Transpower's	See discussion of this in the Options section of the Submission Summary Paper.

[21] The report shows that (a) large scale generation is already commercially viable, so does not require regulated funding to proceed; (b) Smaller initiatives may have short-term deferral benefits but these are insignificant in transmission planning timeframes; and (c) Few alternatives exist that require regulated funding to be commercially viable, and those that do are unlikely to produce significantly greater benefits than transmission investment.

Submitter	Comment (paraphrased)	Response
	information problems, as they give Transpower greater responsibility for the purchase of TAs. The DP options do allow local providers to choose between different TA providers and therefore do partly address information problems. However, the DP options still involve initial decisions on the key issue of grid upgrades by the Commission and Transpower. Therefore, local participants are not able to make a genuine choice between transmission investment and TAs. The CP options do not address Transpower's perceptions about the riskiness of TAs, and the DP options shift this risk to demand-side entities (who are required to undertake procurement under DP options). NERA believe that none of the options address any cultural preference by Transpower for transmission investment over TAs. They further note that none of the procurement options address the sequencing of the GIT. NERA consider that the TA options will address the certainty issue to some extent. However, as the Commission could have required Transpower to consider the TAs as part of the GUP, the Commission causes this problem. NERA provide some details of the Australian approach where the network business rather than the regulator assesses the efficiency of network investment, using cost benefit analysis, and including TA options where there is a clearly identified proponent.	
Trustpower	If postage-tamp transmission pricing is adopted, Trustpower prefers the CP approaches, particularly universal CP, as it does not consider the dynamic efficiency losses are as great as made out. It notes that if locational transmission pricing were adopted then it would prefer limited DP.	Noted.

Submitter	Comment (paraphrased)	Response
Orion	Orion's preferred option is a variation on the minimum DP option. Orion agrees that the DP options will result in lower procurement costs but disagrees that they will be administratively more costly. Orion agrees that postage-stamp pricing is inconsistent with the DP options but believes this can be overcome by: ▪ Requiring the central procurement agency to procure TAs where capacity is required, as determined via the GIT; and/or ▪ Allocating capacity requirements between regions. Orion believes that under this option, distributors should be the demand-side entities responsible for procurement as: • Distributors are natural aggregators of load; • Distributors can facilitate embedded generation; and • Retailers may not have appropriate incentives to fulfil the role (especially where they own generation interests)	See discussion of this in the Options section of the Submissions Summary Paper.
Vector	Vector prefers a market-based alternatives mechanism, because it believes that under- provision of TAs can (or should at least exhaustively attempt to) be solved directly by addressing problems with market design. Vector believes that TAs are a short-term insurance mechanism rather than a medium-term fix to security of supply.	Noted.
WEL	WEL states no preferred option, though notes that it supports incentives for TAs. WEL seeks clarification of the limited DP option as it views that there will be practical difficulties in allocating obligations for capacity to particular regions, and also peak demand at the distribution level is typically	The Commission agrees that the limited DP option would, like all the options, face some practical implementation difficulties. It is not clear with respect to what WEL seeks clarification, but the Commission is

Submitter	Comment (paraphrased)	Response
	controlled by lines companies through clear pricing signals.	happy to discuss this further with WEL if requested.
EECA	Based on an amended set of evaluation criteria (see section on evaluation criteria), EECA scores the minimal CP and limited DP options highest and notes a preference for these over the other options. It believes that these options minimise the slippery slope risks and encourage innovation and diversity with respect to demand-side initiatives. EECA submits that distributors are the most appropriate demand-side entity to undertake procurement as: • They control transmission and distribution pricing signals to consumers and potential TA providers; • They are a more permanent party in the market than retailers; • They have the most to gain from efficient investment in TAs; • Load and network TAs are a natural extension of their business; and • EECA's experience indicates that distributors will best fulfil the role.	Noted.
SENZ	SENZ prefers the minimum CP option as it believes that: • The market response option is fatally flawed in respect of TA investment and operational uncertainty; • Universal CP is fatally flawed in respect to slippery slope risks; • The limited DP option has investment certainty problems and is not consistent with other work streams; and • The RCC option suffers from the same flaws as the limited DP option as well as having the potential to allow vertically integrated generator-retailers to, over time, entrench retail dominance in specific region, with negative implications for retail competition. SENZ believes the conflict of interest between System Operator and	Noted.

Submitter	Comment (paraphrased)	Response
	Grid Owner makes it inappropriate for the System Operator to be the procurement agency.	
MEUG/NZIER	Given the Commission's criteria/weightings, MEUG/NZIER agree with tables 1 and 2 in the consultation paper. MEUG/NZIER as per their proposed weighting and criteria (see section on Evaluation Criteria), prefer and recommend the minimal CP option.	Noted.
Comalco	Comalco prefer option 3 – minimal CP – based on their evaluation criteria outlined above. Comalco also note their objection to the implementation of either the limited DP or RCC options.	Noted.
Norske Skog	Norske Skog prefers Universal CP with the caveat that a subsidised generation TA is required to offer to the market at zero price. This preference would be unchanged if location based pricing was adopted. Norske Skog believes, in respect to the question of which entity is the appropriate procurement agency, the conflict of interest between Transpower's dual roles as System Operator and Grid Owner is significant. For this reason it recommends that the System Operator role be made contestable and, in the interim, the Commission should be the procurement agent. Given the separation of the roles at Transpower, Norske Skog would support the System Operator as the procurement agent.	Noted.
SEF	SEF sets out a preferred option that the GIT should be amended so that distributed generation, demand-side management and reduction of network losses have equal competitive advantage to transmission upgrades. Coupled with this should be a review of current pricing methodologies.	Noted.

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Submitter	Comment (paraphrased)	Response
Green Zephyr	Green Zephyr submits that awareness and education are key, especially in respect to mechanical co-generation, co-location and demand-side use options.	Noted.

Key Issue: ***Other options***

Submitter	Comment (paraphrased)	Response
Transpower	Transpower proposes two other options. 1. Its first preference is for enhancements of the existing market processes including: • Mandatory offering of available generation capacity. Transpower suggests this addresses reliability issues that many transmission investments are proposed for. • Locational transmission pricing. It proposes a simplified zonal pricing system. • Adopting Value of Lost Load (VoLL) pricing when supply interruptions occur. • Publishing and following a coherent and integrated market design. Its second preference (not a preferred option, but offered as an alternative to the Commission's minimum CP option) is for Transpower to evaluate TAs as part of its GUP process as per the practice in the Australian National Electricity Market (NEM).	These proposals are discussed in the Options section of the Submissions Summary paper.
Genesis Power	Genesis proposes an alternative approach with: 1. A much narrower definition of a TA; and 2. A slightly amended GUP and GIT process, whereby TAs are considered by the grid owner within the GUP process.	These proposals are discussed in the Options section of the Submission Summary paper.

[22] Unlike other proponents of similar alternative options, Genesis does not explicitly state who the contract counter-party to such TA procurement contracts should be.

Submitter	Comment (paraphrased)	Response
	It suggests that TAs should only qualify to be TAs if they provide equivalent services to that provided by a transmission option. They should not be able to offer energy into the energy market other than at $0. It suggests that if TAs are procured[22], they shoulde face appropriate performance incentives. It also suggests the GIT process be amended to allow transmission investment to proceed as far as possible without final commitment to major expenditure (up to land purchase and resource consents) even if possible TAs are identified. If the TAs do materialise, the last stages of transmission investment can be delayed. If not, the transmission investment proceeds.	
Contact Energy	Contact believes that the Commission should use central procurement for emergency risk management projects to address urgent issues in Auckland and upper South Island and develop some form of capacity mechanism to improve market design to address free rider and commitment barriers.	See discussion in the Options section of the Submissions Summary paper.
Meridian Energy	Meridian suggests consideration be given to the market response option with market process enhancements: 1. Amend transmission approval process by staggering into two milestones (securing route, construction) to enable more time for market-based new investment and increase certainty for grid users. 2. Improve information provision by publishing part F information documents, and requesting Transpower improve communications to grid users on grid upgrade plans; 3. Assist demand-side alternatives. If it is decided that some intervention is required (which Meridian does not support) then	See discussion in the Options section of the Submissions Summary paper.

Submitter	Comment (paraphrased)	Response
	minimal CP focussed solely on demand-side. Could consider undertaking work on development of demand-side aggregators and potential to use EC's Energy Efficiency fund to fund high-value demand TAs. Meridian notes that, if a procurement option is selected, the NEM model should be considered, under which the Grid Owner is responsible for overall delivered transmission service (clearer contract & accountability model than that suggested in the consultation paper), and TAs are not able to set price during TA periods (enables exercise of market power, with potentially significant wealth transfer implications). Rather, offers are capped and funded in similar way to Huntly voltage support constrained-on in late-1990s. Alternatively, Meridian suggests that procurement could be limited to non-core grid only, and/or to demand-side only. It notes that clear delineation between competitive and regulated activities is required.	
Mighty River Power	MRP identify two options, which it notes are potentially complementary: • Enhanced market response: removing regulatory barriers to TAs by o Locational pricing of interconnection transmission services; o Amending the GIT rules to make it clear that EC will not approve grid upgrades where TAs are adequate substitutes; o Delaying decisions on transmission investment until latest feasible time; • Refined Grid Upgrade Proposal o Amend the Rules to allow Transpower to include TAs in GUP and for the Commission to authorise recovery of the cost of TAs on the same basis as transmission costs.	See discussion in the Options section of the Submissions Summary paper.

Submitter	Comment (paraphrased)	Response
Trustpower	Trustpower does not propose other options but disagrees with ruling out generation and demand side as candidates for funding as a transmission alternative as a variant of the minimal CP option.	Noted.
Orion	Orion would like to see further work on an option whereby Transpower is required to include demand-side management and generation TAs in its GUP. Transpower would be allowed to earn revenue on such efficient investments, as determined by the GIT. Orion would prefer if the Grid Owner (a more appropriate agent than the System Operator) were the central procurer.	See discussion in the Options section of the Submissions Summary paper.
ENA	ENA submits that the Commission should "pursue a policy and statutory environment that allows lines companies to invest in generation and sell the output or manage the risks associated with the output in a commercial and competitive way…" In particular the Commission should consider: • Allowing further vertical integration for lines companies; and • How the Commerce Act Amendment 2001 reduced the legal need for the restrictions in the EIRA.	See discussion in the Options section of the Submissions Summary paper.
EECA	EECA sets out the framework for another option that is voluntary and employs locational pricing combined with a centrally administered fund for TAs. The framework suggested is: • Transmission capacity investments funded centrally using revenues from location-based pricing; • The System Planner allocates funding for GUPs and TAs; • Distributors aggregate and package TA projects then tender them for funding from the System Planner; • The System Planner will contract with successful distributors, and	Noted. The issue of aggregation of TAs will be considered further, as part of implementation issues.

Submitter	Comment (paraphrased)	Response
	penalties will be applied in the event of non-delivery; and • Distributors contract with providers and will be responsible for monitoring compliance with the use of contractual penalties.	
SENZ	SENZ would like to see further work done on the use of a CP option in the near term until such time as a DP regime (if chosen) can be implemented (paragraph 160 of the consultation paper). SENZ notes that to truly 'level the playing field' there should be investment into developing and refining TAs so that they can compete for funding against transmission upgrades.	Noted.
MEUG/NZIER	NZIER dispute that the Rules (Rule 14.3.2.2 in section iii, part F) allow the Commission to "direct Transpower to investigate and apply the grid investment test to transmission alternatives". NZIER note the Rules allow only the Commission to "direct Transpower to investigate and apply the GIT to transmission alternatives". The Commission does not have the power to require Transpower to apply the GIT to reliability TAs. In actuality, the Commission holds no such power. NZIER state that Transpower should not be responsible for making decisions about what TAs should be purchased as they are the grid owner and have a conflict of interest.	Noted. The issue of Transpower as procurement agent for TAs is discussed in the other options section of the Submissions Summary paper.
Comalco	Comalco sees no need for the Commission to undertake further study of any "other options" the consultation paper listed.	Noted.
SEF	SEF identify that Auckland, Christchurch and the north of the South Island would benefit from "electricity efficiency" work and, as such, it should be included in the SOOs.	Noted. However, the Commission further notes that this point is outside the scope of this project.

Submitter	Comment (paraphrased)	Response
Brian Tolley	Mr Tolley submits that there should be a detailed examination of the distribution network capabilities and deficiencies. From this Mr. Tolley recommends the distribution system be changed to: • Overcome climate change challenges; • Integrate distribution generation into the network; • Introduce interval (time of use, or TOU) metering; • Activate distribution networks with more sophisticated secondary infrastructure; • Educate the importance of electricity; and • Introduce more social capital into the industry. Mr Tolley submits that a change should be made in respect to the regulation of lines companies, allowing them to vertically integrate. He posits that this will encourage TAs. Mr Tolley also submits that correct asset valuation and more accurate treatment in terms of depreciation calculations will result in more accurate pricing signals and encouragement of TAs. Mr Tolley suggests that interval (TOU) metering is essential in order to correct price signals. He submits that this will: • Improve load factors; • Facilitate DG; • Overcome the free rider problem; and • Facilitate transmission alternatives.	Noted Noted

Options for Enabling Transmission Alternatives – Summary of Submissions

Key Issue: Cost-benefit analysis (CBA)

Submitter	Comment (paraphrased)	Response
Transpower	Transpower provides a suggested CBA.	See discussion on this CBA in the CBA section of the Submissions Summary Paper.
Genesis Power	Genesis considers a CBA based on national benefits is required before such a significant policy decision. It does not provide any input information for the CBA.	See discussion on this CBA in the CBA section of the Submissions Summary Paper.
Contact Energy	Contact considers that: • Option analysis needs to take account of long-lead times for transmission and uncertainty over delays. • Asymmetric price risk of too much versus too little capacity also needs to be taken account of. • Some TA investment would become redundant if transmission investment subsequently occurred and this cost should be included. • More analysis of reliability differences between TAs and transmission is required. In particular, it questions whether demand-side measures are sufficiently reliable to defer transmission investment. • Administrative costs of minimal CP may be high due to the difficulty of applying the tests.	See discussion on this CBA in the CBA section of the Submission Summary Paper.
Meridian Energy	Meridian suggests that the qualitative evaluation in the consultation paper (in place of quantitative CBA) was inadequate given the nature of the decision. It suggests that the CBA needs to consider the benefits of enabling TAs against (a) the cost of not enabling them; (b) the cost of administering the tests and procurement processes; and (c) the costs of possibly causing costly delays in transmission investment.	See discussion on this CBA in the CBA section of the Submissions Summary Paper.

Submitter	Comment (paraphrased)	Response
	The CBA should also consider reliability levels, cost of subsidies, and option value resulting from a robust transmission system that supports a number of possible generation futures. It should also consider that transmission enhances competitive structure of the market, whereas procuring TAs could increase regionalisation with downstream consequences.	
Mighty River Power	MRP are concerned that the consultation paper did not include a cost-benefit analysis. They cite High Court rulings and Commerce Commission guidelines that favour quantifiable CBAs where possible. MRP consider that the Commission needs to complete a CBA before reaching a view as to the preferred option.	Noted.
Trustpower	Trustpower agrees with the Commission's assessment of likely sources of costs and benefits but notes more may emerge as options are developed.	Noted.
Orion	Orion agrees with the consultation papers CBA outline with the addition of a "security value" component, which recognises that TAs will provide security/reliability gains during the transmission construction period.	Noted.
EECA	EECA would like the CBA to consider how an option would encourage the development of renewable energy, and cost out any environmental externalities. Other than this, EECA agrees with the Commissions proposed CBA.	Noted
SENZ	SENZ would like four additional components to be included in the CBA: 1. WACC; 2. Time period of assessment; 3. Inflation; and 4. Depreciation.	Noted

Submitter	Comment (paraphrased)	Response
MEUG/NZIER	MEUG/NZIER believe that the CBA as set out in the consultation paper appears to cover the required elements.	Noted.

Key Issue: ***Linkages to other work streams***

Submitter	Comment (paraphrased)	Response
Transpower	Transpower notes linkages with the following work streams: • Transpower suggests that if a degree of locational pricing could be introduced then any regulatory involvement in TA procurement would be unnecessary. However, it notes some practical difficulties with full locational pricing and suggests a zonal interconnection pricing option. • Transpower expresses concern that if the Commission requires it to contract with TAs that it may not be able to guarantee its ability to meet grid reliability standards.	Locational Pricing is discussed in the Linkage to other works stream section of the Submissions Summary paper.
Genesis Power	Genesis noted linkages to financial transmission rights and transmission pricing, and also to the GIT process (see earlier comments regarding potential changes to this process).	Noted.
Contact Energy	Contact recommends a specific work stream be set up tasked with developing a capacity mechanism across transmission, wholesale and security of supply. It considers that the Auckland situation requires major transmission investment as soon as possible and that TAs should not be considered as alternatives but as emergency risk management.	See the discussion on capacity mechanisms in the Options section of the Submissions Summary Paper.
Meridian Energy	Meridian notes that it is important to take the time to assess the combined effect of the many governance and regulatory arrangements that have been put in place. It also notes that TAs decisions cannot be made until conclusions are drawn regarding TPM.	Noted.

Submitter	Comment (paraphrased)	Response
Mighty River Power	MRP notes a linkage with locational pricing for transmission (see earlier comments).	Noted.
Trustpower	Trustpower noted the link to the transmission pricing work stream.	Noted.
Orion	Orion agrees that postage-stamp pricing is inconsistent with DP options and would like to see a reconsideration of location-based pricing mechanisms for transmission.	Noted.
Vector	Vector submits that the primary focus for "expeditious resolution" are: • Grid reliability standards – these must be clear, must form specific requirements on Transpower and must be enforceable • Resolving transmission pricing and counterparty arrangements in such a way that signals regional constraints and, therefore, provides incentives for efficient location of generation investment.	Noted.
ENA	ENA identifies the transmission pricing work stream as a relevant and applicable area in that it deals with the nodal price free rider problem described above.	Noted.
EECA	EECA submits that "dampened price signals which weaken incentives to ensure the efficient investment of transmission alternatives" should be redressed by considering changes in transmission and distribution pricing methodologies.	Noted.
SENZ	SENZ agree that postage-stamp pricing of transmission is inconsistent with the DP options. They would like to see the transmission pricing and TA work streams optimised concurrently.	Noted.
MEUG/NZIER	MEUG/NZIER agree there is a linkage between TAs and transmission pricing.	Noted.

Options for Enabling Transmission Alternatives – Summary of Submissions

Submitter	Comment (paraphrased)	Response
Comalco	Comalco's submission notes links between TAs and the transmission pricing work stream. It submits that the current transmission pricing methodology "incorrectly allocate costs of transmission investment… Therefore, in order to reduce investment imperfections, with minimal intervention, the Commission must mandate the deepest definition of connection assets possible and mandate a location-based pricing component for the interconnection charge." Such a change would minimise the intervention required.	Noted.
SEF	SEF identifies a linkage between transmission pricing and TAs.	Noted.
Brian Leyland	Mr Leyland notes a linkage between dry year reserve and TAs work streams stating that the two overlap as "any station installed for one purpose can also serve the other."	Noted.

Key Issue: *Process*

Submitter	Comment (paraphrased)	Response
Transpower	Transpower expressed concern that the proposed change represented a major policy change and as such should be accompanied by a robust cost-benefit analysis. This should include analysis of options including their suggested option 1A "enhanced market design" and option 3B "grid owner contracting for minimal TAs".	Noted.
Genesis Power	Genesis suggests a cost-benefit analysis should have been provided with the first consultation paper.	Noted.
Mighty River Power	MRP considers that there should be a high standard of proof required before the Commission decides to intervene. MRP considers that international experience needs to be reviewed.	Noted. The Commission intends to review overseas models.
MEUG/NZIER	MEUG suggest two steps be taken: 1. The Commission publish a decision on which of the five options it prefers and the rationale for this choice. 2. The Commission issue a consultation paper on implementing the selected option. NZIER notes the comment in the consultation paper that the Rules (Rule 14.3.2.2 in section iii, part F) allow the Commission to "direct Transpower to investigate and apply the grid investment test to transmission alternatives". NZIER note the Rules only allow the Commission to "direct Transpower to investigate and apply the GIT to transmission alternatives". The Commission does not have the power to require Transpower to apply the GIT to reliability TAs. In actuality, the Commission holds no such power. NZIER state that Transpower should not be responsible for making	Noted.

Submitter	Comment (paraphrased)	Response
	decisions about what TAs should be purchased as they are the grid owner and have a conflict of interest.	
SEF	SEF submits that a study of market design should be undertaken with priority given to mechanisms that would enable sustainable energy services.	Noted.