

Reasons for Decision set out in Notice of Intention to Approve Transpower's North Island Grid Upgrade Proposal

23 February 2007

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1 EXECUTIVE SUMMARY

1.1 Context of decision

- 1.1.1 The Electricity Commission (**Commission**) is responsible for regulating the operation of the electricity industry and markets (wholesale and retail) in accordance with the Electricity Act 1992 (**Act**).
- 1.1.2 The Electricity Governance Rules 2003 (**Rules**)¹ are promulgated under the Act. Section III of part F of the Rules includes rules dealing with upgrades to and investments in the national electricity transmission grid owned by Transpower New Zealand Limited (**Transpower**) in “grid upgrade plans” (**GUPs**) that Transpower submits to the Commission for approval.
- 1.1.3 In summary, the Rules seek to facilitate timely investment in transmission infrastructure in an efficient and cost-effective way.
- 1.1.4 The Rules seek to balance the need to ensure a reliable transmission network with the need to avoid over-investment (i.e. investing too early, or in excess of need). Over-investment imposes avoidable costs on those required to pay for such investment including, ultimately, consumers of electricity. The transmission network and associated services are essential, but are provided by a monopoly, Transpower.
- 1.1.5 The Rules seek to ensure the appropriate balance is achieved by requiring an investment proposal to meet a number of tests. The Rules do not require Transpower to identify and propose the cheapest option for grid enhancement. Rather, in broad terms, an investment proposal must meet the reliability standard set by the Rules, comply with good electricity industry practice in doing so, and must be cost-effective by minimising the expected net cost to the market or by maximising expected net benefit to the market, in comparison with a number of alternative projects.

1.2 Decision on Proposal

- 1.2.1 On 20 October 2006, the Commission received a North Island Grid Upgrade Proposal (**Proposal**). The Proposal forms part of the GUP submitted by Transpower on 30 September 2005 (**2005 GUP**), and replaces Transpower’s North Island 400kV upgrade project (**Original Proposal**). The Proposal is a “reliability investment”, as defined in Part A of the Rules.
- 1.2.2 After receiving the Proposal, the Commission carried out analysis and considered the Proposal as required by the Rules.

¹ Unless otherwise stated, all references to rules in this paper are to rules in section III of part F of the Rules, references to schedules are to Schedules in section III of part F, and references to clauses are to clauses in schedule F4 (Grid Investment Test).

1.2.3 The Proposal demonstrates a much better understanding by Transpower of how the Commission interprets and applies the Rules than was the case in relation to the Original Proposal. The Commission has also benefited from a better understanding of the rationale for Transpower's investment proposals. This greater level of understanding has led to a substantial level of agreement between the Commission and Transpower.

1.2.4 The Commission now considers it has sufficient information to make a decision in relation to the Proposal.

Rule requirements

1.2.5 Rule 13.4 provides that, subject to rule 15, the Commission may approve a reliability investment if the Commission is satisfied that the investment:

- (a) reflects good electricity industry practice (**GEIP**) in meeting the grid reliability standards (**GRS**) set out in the Rules;
- (b) complies with the processes set out in the Rules; and
- (c) meets the requirements of the grid investment test (**GIT**).

1.2.6 Rule 15 requires the Commission to publish notice of its intention to approve some or all of the investment proposals in a GUP. The Commission's notice of intention triggers rule 15.2, which enables certain parties to request a public conference. The purpose of a public conference is to provide a final opportunity for comment.²

1.2.7 A public conference has been requested and will be held in May 2007.

Does the Proposal reflect GEIP in meeting the GRS?

1.2.8 The Commission is satisfied that the Proposal reflects GEIP in meeting the GRS.

Has Transpower complied with the processes set out in the Rules?

1.2.9 The Commission is satisfied that Transpower has complied with the processes set out in the Rules.

Does the Proposal meet the requirements of the GIT?

1.2.10 Applying the GIT to the Proposal requires the Commission to agree various "analysis parameters" (such as the appropriate market development scenarios), estimate appropriate costs, and determine the variables used in the sensitivity analysis conducted by the Commission as part of its review of the Proposal. The direction and likely magnitude of material market benefits or costs that cannot be quantified must also be identified.

² Rule 15.3.

- 1.2.11 In exercising its judgment in relation to these matters, which collectively comprise the inputs and assumptions used to apply the GIT, the Commission must have regard to its statutory functions, objectives, and outcomes set out in the Act, the objectives and outcomes in the Government Policy Statement on Electricity Governance (**GPS**),³ and the purposes of the Rules.
- 1.2.12 However, none of these statutory instruments determine the exact inputs or assumptions that must be used, or the value attributable to those inputs or assumptions. Rather, the statutory instruments may assist the Commission to determine the inputs and assumptions, and related values, that it will use when faced with a number of possible alternatives.
- 1.2.13 Accordingly, the Commission emphasises that, although the models used by the Commission and Transpower are extremely sophisticated and are designed to produce an exact NPV number, that number may give a false sense of precision as to the expected net market cost, or expected net market benefit, of a proposed investment and relevant alternative projects.
- 1.2.14 In relation to the Proposal, while Commissioners agree on a substantial number of inputs and assumptions, one Commissioner differs with the other Commissioners in exercising his judgment to set some of those inputs and assumptions.
- 1.2.15 The differing views as to those matters led to three Commissioners concluding that the Proposal meets the requirements of the GIT, and one Commissioner concluding that it does not.⁴
- 1.2.16 Accordingly, by a majority, the decision of the Commission is that the Proposal meets the requirements of the GIT, and therefore satisfies rule 13.4.1.3.

1.3 Intention to approve the Proposal

- 1.3.1 By a majority, the Commission concludes that the Proposal satisfies the requirements of rule 13.4.
- 1.3.2 On 31 January 2007, the Commission issued notice of its intention to approve the Proposal.
- 1.3.3 As part of its decision, the Commission wishes to put forward to Transpower three recommendations. They are:
- (a) The Commission expects that Transpower will use efficient project management techniques to manage project costs and risks and, on an ongoing basis, will review the need date for the Proposal in light of changing circumstances, keeping in mind the need to avoid unnecessary

³ A revised GPS was published on 26 October 2006. A copy of the GPS is available on the Ministry of Economic Development's website, www.med.govt.nz.

⁴ Only 4 Commissioners (Deputy Chair Peter Harris, and Commissioners Close, Dell, and Pinnell) were entitled to vote in relation to the Proposal. Commission Rodger, who recently joined the Board of the Commission from the Board of Transpower, did not take part in discussions, or vote on issues, related to the Proposal.

early expenditure while ensuring that the relevant assets are commissioned before they are needed. As part of efficient project management, the Commission also expects that Transpower will demonstrate the need to incur costs before committing to costs, and will publish regular reports that set out the progress of implementing the Proposal against both expected costs and costs with contingencies, and the reason(s) for any divergence.

- (b) The Commission expects Transpower to use reasonable endeavours to obtain consent under the Resource Management Act 1991 for the Pakuranga substation to be equipped with air insulated switchgear (**AIS**) rather than gas insulated switchgear (**GIS**). The Commission notes that it is not clear that GIS will be required at Pakuranga, and although the Commission's approval will cover the construction and commissioning of a GIS switchyard, the Commission views this as effectively a contingency. The Commission expects Transpower to diligently seek to minimise project costs and, if the construction of an AIS switchyard results in lower overall costs, the Commission expects Transpower to actively seek this outcome.
- (c) The Commission expects that Transpower will provide to the Commission as soon as possible an asset capability statement regarding the intended rating of the assets to which the Proposal relates, their electrical characteristics, and the reliability and availability expected for the assets. The asset capability statement must be consistent with performance assumed in applying the GIT. For example, the asset capability statement should include the expected single circuit and double circuit forced outage rates, with an expected repair time. The asset capability statement must also be consistent with the proposed interconnection rules.

2 INTRODUCTION AND PURPOSE OF THIS DOCUMENT

2.1 Introduction

The Proposal

- 2.1.1 On 20 October 2006, the Commission received the Proposal from Transpower. The Proposal forms part of the 2005 GUP, and replaces an investment that was originally included in the 2005 GUP, namely the Original Proposal.⁵
- 2.1.2 The Proposal is designed to ensure electricity supply to the Auckland region after 2013. The Proposal comprises a suite of measures, the centrepiece of which is the construction of a 400kV-capable overhead transmission line between Whakamaru in South Waikato and a new substation in South Auckland. The proposed transmission line would operate initially at 220kV. If approved, construction of the proposed line would give Transpower the option to convert the line to 400kV operation at a later date.
- 2.1.3 The Proposal to which the Commission's decision relates includes acquiring designations, consents, and easements that would allow for a future upgrade to 400kV operation, but does not include the actual works required to convert the line to 400kV operation, such as new 400/220kV transformers or a new switchyard. Transpower and the Commission agree that converting the proposed transmission line from 220kV operation to 400kV operation requires separate consideration and, if appropriate, approval at a later date under the prevailing regulatory regime at that time.
- 2.1.4 However, the Commission has modelled the later upgrade of the line to 400kV operation, in order to assess the value of the option presented by constructing a 400kV-capable line, as part of applying the GIT to the Proposal.

The Rules

- 2.1.5 The Commission is required to consider and assess the Proposal in accordance with the Rules.
- 2.1.6 Specifically, rule 13.4 provides that, subject to rule 15, the Commission may approve a reliability investment if the Commission is satisfied that the investment:
- (a) reflects GEIP in meeting the GRS (rule 13.4.1.1);
 - (b) complies with the processes set out in the Rules (rule 13.4.1.2); and
 - (c) meets the requirements of the GIT (rule 13.4.1.3).
- 2.1.7 Rule 15 requires the Commission to publish notice of its intention to approve some or all of the investment proposals in a GUP. The Commission's notice of

⁵ The Original Proposal involved the construction of a 400kV double circuit line between Whakamaru near Tokoroa, and Otahuhu in South Auckland.

intention triggers rule 15.2, which enables certain parties to request a public conference. The purpose of a public conference is to provide a final opportunity for comment.⁶

- 2.1.8 If the Commission is satisfied that the requirements of rules 13.4 and 15 are met, it may approve the investment proposal. If the Commission approves an investment proposal, Transpower is able to recover the approved costs of that investment from designated transmission customers in accordance with the transmission pricing methodology set out in section IV of part F of the Rules.⁷

Notice of Intention

- 2.1.9 On 31 January 2007, the Commission issued a notice of its intention to approve the Proposal. The notice was issued in accordance with rule 15.1.
- 2.1.10 The Commission has received a number of requests under rule 15.2 for a public conference. The Commission has agreed to hold a public conference. The conference will be in May 2007.
- 2.1.11 In order to make the conference process as transparent and efficient as possible, the Commission has invited interested parties (whether intending to present at the public conference or not) to provide a written submission in advance of the conference in order to assist the Commission to finalise its decision.
- 2.1.12 Following the public conference, the Commission may:
- (a) confirm its decision in accordance with rule 15.5.1; or
 - (b) amend the Proposal in accordance with rule 15.5.1; or
 - (c) decline to approve the Proposal and publish reasons in accordance with rule 13.4.2.

2.2 Purpose

- 2.2.1 The purpose of this document is to:
- (a) present the Commission's analysis as to whether the Proposal meets the requirements of rule 13.4, including setting out both the majority and minority views of the Commissioners; and
 - (b) explain the reasons supporting the Commission's intention, as set out in the notice of intention issued on 31 January 2007, to approve the Proposal.

⁶ Rule 15.3.

⁷ Rule 17.1. Under section 57MA of the Commerce Act 1986, the Commerce Commission must "take into account" a decision under the Rules that relates to or affects the quality standards or pricing methodologies applicable to Transpower before exercising any of its powers under Part 4A of the Commerce Act (which relates to the regulation of Transpower's revenue requirements).

3 BACKGROUND

3.1 Role of the Commission and decision-making context

- 3.1.1 The Commission is responsible for regulating the operation of the electricity industry and markets (wholesale and retail) in accordance with the Act.
- 3.1.2 The Commission's principal objectives, as set out in the Act, are to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner, and to promote and facilitate the efficient use of electricity. The Commission must have the objectives and the specific outcomes listed in section 172N of the Act in mind in exercising its powers.
- 3.1.3 The Act also sets out a number of specific functions of the Commission, including to:
- (a) administer the electricity governance regulations and rules (section 172O(1)(b)); and
 - (b) give effect to GPS objectives and outcomes (section 172O(1)(j)).
- 3.1.4 In relation to transmission, part F of the Rules sets out a series of processes that the Commission must follow to produce comprehensive transmission pricing, transmission contracting, and transmission investment arrangements. Under section III of part F, the Commission has a key responsibility in considering for approval investments in the grid proposed by Transpower.
- 3.1.5 Rule 2 sets out the purposes of the rules in section III of part F as being to:
- “2.1 facilitate **Transpower’s** ability to develop and implement long term plans (including timely securing of land access and resource consents) for investment in the **grid**;*
 - 2.2 assist **participants** to identify and evaluate investments in **transmission alternatives**;*
 - 2.3 facilitate efficient investment in generation;*
 - 2.4 facilitate any processes pursuant to Part 4A of the Commerce Act 1986; and*
 - 2.5 enable the cost of approved investments to be recovered through the **transmission pricing methodology** applied in **transmission agreements**.”*
- 3.1.6 In summary, the Rules seek to facilitate timely investment in transmission infrastructure in an efficient and cost-effective way.

- 3.1.7 The Rules also seek to balance the need to ensure a reliable transmission network with the need to avoid over-investment (i.e. investing too early, or in excess of need). Over-investment imposes avoidable costs on those required to pay for such investment, including, ultimately, consumers of electricity. The transmission network and associated services are essential, but are provided by a monopoly, Transpower.
- 3.1.8 When exercising its powers under part F, the Commission must have regard to its statutory functions, objectives, and outcomes, and the objectives and outcomes specified in the GPS. However, while the Commission's functions, objectives and outcomes must be taken into account, they cannot override rules that do not permit any discretion.

3.2 Transpower

- 3.2.1 Transpower plays a central role in the New Zealand electricity sector. It owns and operates the transmission grid that transports electricity at high voltage from power stations to consumers. It has a crucial role in maintaining the reliability and stability of the transmission system.
- 3.2.2 Transmission planning is central to Transpower's abilities to discharge these obligations. Transpower has been signalling its view for some time that the transmission grid may, in places, be reaching the limits of its existing capability to provide a reliable or secure means of connecting generation to meet growing consumer demand. Transmission investment decisions are often characterised by complex technical analysis, comprehensive planning studies, and long lead times. Therefore, Transpower has initiated planning studies and is progressing a number of major options for augmenting the grid over the next 5 to 10 years.
- 3.2.3 Transpower has been actively considering and consulting on options for a major upgrade of the 220kV "backbone" of the national grid as a "System Vision" project since 2002. Initially, this focused on a proposed strategy to position the "core grid"⁸ at 330kV to accommodate growth to 2020 and beyond. Further consideration by Transpower culminated in it instead preferring a long-term vision of a 400kV core grid.
- 3.2.4 Transpower explains its "National Grid Vision" in the Overview to the Proposal. Specifically, Transpower states that its 40-year vision for the national grid is to move gradually to a 400kV backbone. Transpower states that "*New Zealand is following rather than leading international practices and eventually stepping up to a high voltage for its National Grid,*"⁹ and lists a number of countries that already have transmission voltages similar or in excess of 400kV, including the United Kingdom, France, Ireland, Australia (Victoria), and Singapore.
- 3.2.5 In support of the Proposal, Transpower also cites mitigating the impact of new lines. Transpower states that:

⁸ The "core grid" is set out in the Core Grid Determination in schedule F3A, which came into force on 16 February 2006.

⁹ Proposal, Transpower Overview, section 8.2, page 40.

“Transpower is aware that while public appetite for a reliable electricity supply is high, this does not equate to a hunger for new transmission lines. The 400kV development path responds to that concern by not only providing fewer lines over time than a 220kV path, but also allowing a greater planning flexibility in their introduction. So as part of our vision for the future, we are considering ways in which the impact of major lines can be mitigated for communities they affect”¹⁰

3.3 Background to the Proposal

Interim grid expenditure applied for

- 3.3.1 On 31 May 2005, Transpower submitted an investment proposal to the Commission for a 400kV double circuit transmission line between Whakamaru and Otahuhu under the transitional provisions in rule 16.
- 3.3.2 On 12 July 2005, the Commission declined approval of Transpower’s proposed Auckland 400kV investment under rule 16, because it did not consider the expenditure reasonably prudent or necessary to meet Transpower’s current grid reliability standards as required by rule 16. However, the Commission invited Transpower to submit a revised proposal for interim grid expenditure for any prudent expenditure on preparatory work, and required that Transpower include the main proposed Auckland 400kV investment as part of its first GUP.

2005 GUP

- 3.3.3 On 30 September 2005, Transpower submitted the 2005 GUP. The 2005 GUP proposed the following grid augmentations:
- (a) the Original Proposal, namely a 400kV transmission line from Whakamaru to Otahuhu, with an estimated nominal capital cost of \$622 million, as presented in the second volume of the 2005 GUP; and
 - (b) an upgrade to the high voltage direct current (HVDC) inter-island link, with an estimated nominal capital cost of \$795 million, as presented in the third volume of the 2005 GUP.
- 3.3.4 In October 2005, Transpower submitted two smaller (but significant) investments as a fourth volume of the 2005 GUP. These are thermal upgrades in the central North Island and to the Bunnythorpe-Haywards 1 and 2 lines, with estimated nominal capital costs of \$20.3 million and \$7 million respectively.
- 3.3.5 Those projects were previously submitted by Transpower as “tactical transmission upgrades” under rule 16, before being resubmitted as part of the 2005 GUP.
- 3.3.6 The Proposal was submitted in October 2006, as discussed further below.

¹⁰ Proposal, Transpower overview, section 8.1.3, page 37.

- 3.3.7 Finally, on 11 December 2006, Transpower submitted as volume 5 of the 2005 GUP an investment proposal comprising the construction of a new 220kV GIS switchyard adjacent to, but physically separate from the existing 220kV AIS switchyard at Otahuhu.

Decision-making in stages – the Original Proposal

- 3.3.8 The Commission decided to consider the 2005 GUP in stages starting first with an analysis of the Original Proposal.
- 3.3.9 On 27 April 2006, the Commission gave notice under rule 15.1 that it intended to decline to approve the Original Proposal. The Commission also issued a draft decision document in April 2006 (the **April 2006 Draft Decision**) setting out reasons for its decision. The Commission then commenced a consultation process on the Original Proposal and its draft decision to not approve the Original Proposal.
- 3.3.10 On 31 May 2006, Transpower informed the Commission of its intention to amend the Original Proposal. Transpower also asked the Commission to suspend consideration of the Original Proposal, and the Commission agreed to that request.
- 3.3.11 From June to mid-October 2006, the Commission engaged with Transpower with a view to providing Transpower a greater degree of clarity as to:
- (a) how the GIT is applied by the Commission;
 - (b) the level of analysis the Commission expects Transpower to undertake prior to proposing an investment; and
 - (c) the key inputs and assumptions used by the Commission when it applies the GIT to a proposed investment.

Transpower prepares and submits Proposal

- 3.3.12 In early October 2006, Transpower advised the Commission that it intended to provide another proposal for the Commission to consider, and that it no longer wished to progress the Original Proposal to which the notice of intention issued on 27 April 2006 related.
- 3.3.13 Accordingly, the Commission revoked its notice of intention to decline to approve the Original Proposal. On 20 October 2006, Transpower submitted the Proposal to the Commission.
- 3.3.14 In accordance with rules 13.3.2 and 13.3.5, on 24 October 2006 the Commission initiated a comments period (**Comments Period**) by giving notice that it was providing designated transmission customers and parties substantially affected by the Proposal with an opportunity to:
- (a) provide written comments on the Proposal; and

(b) request that the Commission consider alternatives to the Proposal.

3.3.15 Comments and requests were required to be received by 22 November 2006.

3.4 Analysis and information assisting Commission deliberations

Reports

3.4.1 The Commission was assisted in its decision-making by analysis by its staff and a number of advisers of the information provided by Transpower.

3.4.2 In particular, the report entitled "*Economic Analysis of the Revised North Island Grid Upgrade Project*", dated 23 February 2007 (**Commission Economic Report**) reflects more fully the analysis undertaken by the Commission and advice received from its independent advisers.

3.4.3 Other reports by the Commission's advisers include the following, which are available on the Commission's website:

(a) Transmission Augmentations into Auckland: Technical Review of Transpower's Amended Proposal, S001-05 Final Revision 0, System Studies Group NZ Ltd, 30 January 2007 (**SSG report**);

(b) Comments on the Effect of Constrained-on Generation on the 2013 Need-date for a New Line (Revision 1), System Studies Group NZ Ltd, 12 December 2006;

(c) Review of Calculations for Ultimate Thermal Capacity (Revision 1), System Studies Group NZ Ltd, 13 November 2006;

(d) Check of transmission augmentations in the calculation of losses for Transpower's 400kV proposal (Revision 1), System Studies Group NZ Ltd, 8 November 2006;

(e) Review of Transpower's Amended Proposal, North Island Grid Upgrade Project, Reference 24919, Revision 1, Connell Wagner Limited, 12 December 2006 (**Connell Wagner report**);

(f) Review of EMF Profile for 400kV Transpower Structures, 156258A-REPT-001.doc Rev 1, Parsons Brinckerhoff Associates, 22 November 2006 (**PBA EMF report**);

(g) North Island Upgrade Project: Review of the Capital Cost Estimates for Transpower's Amended Proposal of October 2006, Parsons Brinckerhoff Associates, 15 December 2006 (**PBA costs report**);

(h) Review of 400kV & 220kV Transpower Proposal, 156258A-REPT-003.doc, Parsons Brinckerhoff Associates, 12 December 2006 (**PBA design report**);

- (i) OTA-WKM A&B Cables and C105 Tower Review, 156258A-REPT-001.doc Rev 3, Parsons Brinckerhoff Associates, 30 January 2007 (**PBA duplexing report**);
- (j) Confidence Issues Related to Timing of Transmission Investments, Tim Hazledine, Department of Economics, University of Auckland, 18 December 2006;
- (k) Report on the Castalia Report to Transpower concerning Foreign Direct Investment effects of the upgrade of electricity transmission infrastructure serving Auckland, Tim Hazledine, Department of Economics, University of Auckland 21 November 2006; and
- (l) Comments on Castalia's report to Transpower entitled "Discount Rate for the Grid Investment Test", Graeme Guthrie, 23 November 2006.

Information requested and received under rule 13.3.3

3.4.4 After receiving the Proposal, the Commission asked Transpower a number of questions and sought further information from Transpower in accordance with rule 13.3.3. The Commission's requests, and Transpower's responses, are listed below and available on the Commission's website:

- (a) Commission's request for information 17 November 2006;
- (b) Transpower's response dated 29 November 2006 to the Commission's 17 November 2006 request for information;
- (c) Commission's request for information 8 December 2006;
- (d) Transpower's response dated 15 December 2006 to the Commission's 8 December 2006 request for information;
- (e) Commission's request for information 20 December 2006;
- (f) Commission's request for information 21 December 2006;
- (g) Transpower's response dated 17 January 2007 to the Commission's 20 December 2006 and 21 December 2006 requests for information;

Comments

3.4.5 The Commission has also taken into account comments received during the Comments Period. Where relevant, the Commission refers to comments received during the Comments Period later in this document. However, the general thrust of comments received is summarised below.

3.4.6 Vector and Northpower, two distribution companies that operate in the area that would be served by the upgraded transmission lines proposed by Transpower, give strong support for the Proposal on the grounds that it assures reliability of

supply. Their views are consistent with added emphasis on reliability in the GPS.

- 3.4.7 The major generator-retailers, including those which have plans to invest in generation in the upper North Island, give unequivocal support to the Proposal on the grounds of reliability and the effective operation of the electricity market.
- 3.4.8 Business interests are divided. Some support an upgrade, provided that it is done in a cost-effective way. Others are reluctant to contribute to the cost of an upgrade outside the areas where they are located. This latter concern may be more of an issue for transmission pricing than the GIT.
- 3.4.9 A small number of submitters supported the Proposal on the grounds that they believe it will facilitate the development of renewable forms of generation.
- 3.4.10 Finally, land owners and residents in the areas to be traversed by the transmission line to which the Proposal relates expressed strong opposition. Many of their concerns were in relation to disruptive commercial and social effects, and adverse environmental impacts, of the lines.
- 3.4.11 The Commission notes that its review of the Proposal under the Rules is not a substitute for the process carried out under the Resource Management Act 1991 (**RMA**). That process will be carried out separately in accordance with the provisions of the RMA.
- 3.4.12 As part of that process, land owners and other affected parties are able to engage with Transpower on a bilateral basis in relation to compensation for the effects of the lines, and costs associated with easements.
- 3.4.13 The link between the RMA process and the process under the Rules is that the amount Transpower assumes is necessary for compensation and costs associated with securing land access/the RMA process are included in the costs considered by the Commission in reviewing the Proposal. In this way, the Commission takes into account the effects of the Proposal on landowners and other parties who are directly affected by the route of the transmission line to which the Proposal relates.
- 3.4.14 The comments received by the Commission reflect the tension inherent in the judgment that the Commission is required to exercise when considering the costs and benefits of the Proposal.
- 3.4.15 On one hand, there is a convergence between the comments and the priorities expressed in the GPS for timely decision-making, business confidence arising from more certainty around long-term planning and infrastructure development, adequate capacity to allow for the development of renewable generation in as-yet unspecified locations, and the priority to be given to reliability over cost where there is an element of uncertainty.

- 3.4.16 On the other hand, there is a recognition that adequate reliability may be able to be secured by more than one form of transmission upgrade, and that there may be avoidable costs associated with an alternative to a very large upgrade in grid capacity. The Rules themselves at present require that, when a proposed investment is one of a number of possible alternative investment proposals, in order to be approved, the proposed investment must minimise expected net market costs, or maximise expected net market benefits when compared with those alternative investment proposals.
- 3.4.17 A complete summary of submissions is available on the Commission's website.

4 TRANSPOWER'S PROPOSAL

4.1 Summary of the Proposal

4.1.1 In its Application for Approval, Transpower described the measures for which approval is sought as follows:¹¹

- *“Procure, construct, commission and operate a 220kV switching station in the vicinity of Drury and upgrade the 220kV Otahuhu – Whakamaru C line by 2010.*
- *Procure, construct, commission and operate 350MVAR of new static reactive plant at Otahuhu substation by 2010.*
- *Procure, construct, commission and operate a new double-circuit, steel lattice tower, overhead transmission line of approximately 190km from a new substation near the existing Whakamaru substation to a new transition station in the vicinity of the South Auckland urban boundary, that is capable of:*
 - *220kV operation; and*
 - *future 400kV operation of around 2700MVA, subject to later Commission approval of and Transpower commissioning of 220kV-400kV transformers and associated switchyards near the existing Whakamaru substation and in the vicinity of the South Auckland urban boundary.*
- *Procure, construct, commission and operate two underground cables from the new transition station in the vicinity of the South Auckland urban boundary to Pakuranga substation that:*
 - *are capable of 220kV operation; and*
 - *have a continuous rating of around 660MVA per set of cables*
- *Procure, construct, commission and operate the necessary substation / transition station facilities near the existing Whakamaru substation (Air Insulated Switchgear [AIS]), a transition station in the vicinity of the South Auckland urban boundary (AIS), and Pakuranga substation (Gas Insulated Switchgear [GIS]).*
- *Plan the works, including the acquisition of designations, consents and easements to allow for future upgrade to 400kV operation through future addition of:*

¹¹ Proposal, Application for Approval (**Application for Approval**), page 5.

- *new 400/220kV transformers and associated works near the existing Whakamaru substation to interconnect with the existing 220kV system;*
 - *a new switchyard in the vicinity of the transition station with new 400/220kV transformers and associated works;*
 - *new overhead lines or underground cables to connect the new switchyard with the new transition station;*
 - *new 220kV underground cables to Otahuhu substation; and*
 - *extensions to the Otahuhu switchyard(s).*
- *Carry out the works necessary to convert and connect the existing 110kV Otahuhu-Pakuranga line to 220kV operation, for which it is already designed and consented;*
 - *Dismantle the existing 110kV Arapuni to Pakuranga transmission line*
 - *Obtain designations, easements, resource consents and property purchases necessary for all the above works.*
 - *Plan for a commissioning date for the major projects above of 2011 to prudently allow for potential delays due to delivery, designation, consenting and easement risks.”*
- 4.1.2 A copy of the Proposal and additional supporting information provided by Transpower is available on the Commission’s website: www.electricitycommission.govt.nz.
- 4.1.3 The Proposal was submitted by Transpower as a reliability investment on the basis that it is designed to reduce expected unserved energy.¹² In this regard, Transpower has relied on the needs analysis in relation to the Original Proposal, in which Transpower concluded “*there is some risk of electricity demand not being supplied into the upper North Island at times of peak loading from 2010 and that new investment is required to maintain security of supply into the region.*”¹³
- 4.1.4 The Commission is satisfied on the basis of the information it has to date that the Proposal would have the primary effect of reducing expected unserved energy and, therefore, it is appropriate to consider it as a reliability investment under rule 13.

¹² Reliability investments are defined in the Rules as “*investments by **Transpower** in the **grid**, or alternative arrangements by **Transpower** the primary effect of which is, or would be, to reduce **expected unserved energy**”.*

¹³ Original Proposal, Executive Summary, paragraph 6.

4.2 Overview of estimated costs

- 4.2.1 Transpower is seeking approval of costs incurred by it in the implementation of the Proposal in accordance with the 90% limit of project costs in 2011 dollars.¹⁴ This is \$824 million in 2011 dollars (\$683 million in 2006 dollars).
- 4.2.2 This amount includes the cost of transmission works, acquisition of property rights, and project management.
- 4.2.3 Table 4.1 below breaks down Transpower's estimated 90% limit of project costs in 2011 dollars:

Table 4.1: Transpower's estimate of project costs

Cost category		2011 \$ million
Investigations		27
Property		116
Environmental		8
Transmission Works:		
- Lines	<i>400kV line</i>	203
	<i>Up-rate OTA-WKM C</i>	4
	<i>OTA-PAK 110kV Circuits</i>	1 ¹⁵
	<i>Drury</i>	2
- Substations	<i>Otahuhu</i>	12
	<i>Whakamaru</i>	13
	<i>Pakuranga</i>	55
	<i>Drury</i>	16
	<i>Static Compensation</i>	8
- Cable		110
Dismantling		5
Project Management		34
Subtotal		614
Contingency		105
Exchange Rate		25
Interest During Construction		80
TOTAL		824

- 4.2.4 The Commission's approval is intended to accurately define the maximum amount that can be recovered from designated transmission customers. For this reason the Commission intends to approve \$824 million (including contingencies) in 2011 dollars, or the actual cost of implementing the Proposal, whichever is the lesser. This effectively establishes the "book value" for the regulatory asset base.

4.3 Timing of Proposal

- 4.3.1 Transpower has stated that the timetable for the Proposal is as follows:¹⁶

¹⁴ Application for Approval, page 6.

¹⁵ Transpower states in the Application for Approval that the cost attributable to the OTA-PAK 110kV circuits will increase by \$7 million to \$10 million if the Otahuhu diversity project (which is a supplement to the 2005 GUP) does not proceed. The Commission's approval of the Proposal does not cover any such cost increase.

Table 4.2: Timing of Proposal

Proposal Timing (includes risk allowance)	Augmentation
2009	Install 250MVAr static reactive plant at Otahuhu
	Decommission the 110kV ARI-PAK line
2010 (short term projects)	Establish Drury switching station
	Implement thermal upgrade for Otahuhu-Whakamaru C line
	Install 100MVAr static reactive plant at Otahuhu
2011 (major projects)	Establish 220kV substation adjacent to existing Whakamaru substation (Whakamaru North)
	Cable Transition Station, South Auckland
	400kV double circuit line from Whakamaru to cable transition station in South Auckland. Circuits operated at 220kV.
	2 x 220kV cables from transition station to Pakuranga substation
	220kV sub station at Pakuranga
	Install 3 x 120MVA supply transformers at Pakuranga substation
	Increase operating voltage of existing 110kV OTA-PAK line to 220kV

- 4.3.2 The “short-term projects” are “projects that may be cost-effective to pursue... in the short-term prior to the major upgrade. Transpower accepts that such cost-effective short-term projects would form part of the proposed upgrade”.¹⁷
- 4.3.3 Accordingly, the short-term projects are part of the Proposal for which approval is sought.
- 4.3.4 Finally, Transpower has allowed for 2 years to account for delivery risk. That is, while Transpower considers the need date is 2013, the proposed commissioning date of the Proposal is 2011.¹⁸

¹⁶ Application for Approval, page 69.

¹⁷ Application for Approval, paragraph 306, page 64.

¹⁸ Further explanation of Transpower’s reasoning is set out in the Application for Approval, section 7, page 63.

5 INTERPRETATION OF RULE REQUIREMENTS

5.1 Background

5.1.1 As set out in section 2 above, the Commission may approve a reliability investment only if the Commission is satisfied that that investment:

- (a) reflects GEIP in meeting GRS (rule 13.4.1.1); and
- (b) complies with the processes set out in the rules (rule 13.4.1.2); and
- (c) meets the requirements of the GIT (rule 13.4.1.3).

5.1.2 This section sets out how the Commission has interpreted and applied the above tests.

5.2 GEIP and the GRS

5.2.1 The Commission interprets rule 13.4.1.1 as requiring it to decide whether it is satisfied that the proposed investment both:

- (a) meets the GRS; and
- (b) reflects GEIP.

Meeting the GRS

5.2.2 The GRS are contained in schedule F3. The essence of the GRS is contained in clause 4 of schedule F3, which states as follows:

*“For the purpose of clause 3, the **grid** satisfies the **grid reliability standards** if:*

*4.1 the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all **economic reliability investments** were to be implemented [(**Economic Reliability Standard**)]; and*

*4.2 with all **assets** that are reasonably expected to be in service, the power system would remain in a **satisfactory state** during and following any **single credible contingency event** occurring on the **core grid**.[(**N-1 Safety Net**)¹⁹].²⁰*

5.2.3 Further, clause 6 of schedule F3 provides that:

“For the purpose of clause 4.1 and 4.2 [of schedule F3], the expected level of reliability, and state, of the power system must be assessed using the range of relevant operating conditions that could reasonably be expected, having

¹⁹ Where “N” refers to a number of transmission facilities, and “-1” refers to a “single credible contingency event”, as defined in part A of the Rules.

²⁰ Transpower refers to clauses 4.1 and 4.2 as the “probabilistic limb” and “deterministic limb” respectively.

*regard to the possible future scenarios set out in the **statement of opportunities.***

Reliability benefits in the GRS

- 5.2.4 The Economic Reliability Standard in the GRS means that Transpower must incorporate a “probabilistic” approach when deciding whether to upgrade the grid beyond the *N-1* Safety Net. The GRS also requires a probabilistic approach when assessing the expected net market costs of investments that are necessary to comply with the *N-1* Safety Net.
- 5.2.5 The probabilistic planning approach involves estimating the probability of network and generator contingencies (based on historically observed failure rates or international benchmarks), calculating the overall capacity and reliability of the interconnected system containing these assets, and then using the “value of unserved energy” to calculate the likely costs associated with numerous outage combinations. These costs are regarded as the “reliability benefits” and are used:
- (a) to decide on an economic basis whether proposed transmission investments should be made earlier than otherwise, or whether additional investments are required to yield a security standard at levels greater than the *N-1* Safety Net minimum; and
 - (b) to select investments which minimise the expected net market cost of achieving the *N-1* Safety Net.
- 5.2.6 This approach allows direct numerical consideration of generation and network elements that are reasonably likely to be in service, rather than consideration on a simple discretionary deterministic basis.
- 5.2.7 In relation to the *N-1* Safety Net, Transpower states that it:
- “has interpreted this deterministic limb to mean N-1 (the power system would remain in a satisfactory state during and following any single credible contingency event occurring on the core grid) with one generator out of service (with all assets that are reasonably expected to be in service). This standard is known as N-G-1, being shorthand for N-1 with the largest generator out of service”.*²¹
- 5.2.8 Transpower states that its interpretation of the GRS does not mean that it considers that it is reasonable to expect that a generating unit will always be out of service. Rather, Transpower states that it *“considers it reasonable and prudent to plan on being able to maintain N-1 security when a generating unit (e.g. a unit at Otahuhu B) is out of service”.*²²

²¹ Application for Approval, paragraph 187, page 43.

²² Application for Approval, paragraph 189, page 43.

- 5.2.9 In the Commission's view, the probability that a generation unit will not be available at peak is best addressed through the Economic Reliability Standard in the GRS.
- 5.2.10 However, the Commission agrees with Transpower that the potential difference in interpreting the GRS, and in particular the *N-1* Safety Net, is not material for this Proposal because both interpretations lead to an *N-G-1* approach in this case.

Definition of "good electricity industry practice"

- 5.2.11 The GRS do not directly prescribe performance criteria required to ensure that the grid can be operated in a safe and secure manner and be consistent with GEIP.
- 5.2.12 GEIP is not defined in the Rules. Therefore, the Commission is required to adopt an interpretation. In the April 2006 Draft Decision, the Commission adopted the following definition:

"The exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission network under conditions comparable to those applicable to the relevant grid assets consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law."²³

- 5.2.13 The Commission considers that this definition remains appropriate.

Additional factors

- 5.2.14 In the April 2006 Draft Decision, the Commission also concluded that there were a number of "additional factors" required to be met by a proposed investment.²⁴
- 5.2.15 On reflection, the Commission does not consider that these factors need to be separately considered when assessing whether a proposed investment meets GEIP.
- 5.2.16 The additional factors primarily focus on how a project is executed and as such are likely to have been taken into account by Transpower in determining the expected project cost. Accordingly, they are not separately taken into account in determining costs and benefits in the course of applying the GIT in this case.

²³ April 2006 Draft Decision, paragraph 6.2.18, page 30.

²⁴ April 2006 Draft Decision, paragraphs 6.2.20-6.2.24, pages 30-31.

5.3 Compliance with rule processes

- 5.3.1 Rule 13.4.1.2 requires that the “proposed reliability investment ... complies with the processes set out in these rules”.
- 5.3.2 For the reasons set out in the April 2006 Draft Decision, the Commission considers that rule 13.4.1.2 should be interpreted as requiring Transpower to comply with the processes required by the Rules in relation to the proposed investment under consideration.²⁵
- 5.3.3 Those processes include:
- (a) submitting a GUP to the Commission within three months of receiving a written request from the Commission, or such other date as the Commission agrees (rule 12.2);
 - (b) providing such content in the GUP as prescribed in writing by the Commission (as relevant to the proposed investment under consideration) (rule 12.3.4);
 - (c) complying with the timetable for consultation and approval of the investment under consideration as agreed by the Commission and Transpower or stipulated by the Commission (rule 13.2); and
 - (d) answering the Commission’s questions and carrying out investigations and evaluations as required by the Commission under rule 13.3.3.

5.4 The GIT

- 5.4.1 Of the three tests that a proposed grid investment must meet in order for the Commission to approve it, the GIT requires the most comprehensive analysis.
- 5.4.2 The rigour and comprehensiveness of the analysis undertaken in applying the GIT must be commensurate with the estimated capital expenditure required for the proposed investment.²⁶
- 5.4.3 The essence of the GIT is in clause 4, which states:

“4. A **proposed investment** satisfies the **grid investment test** if the **Board** is reasonably satisfied that:

4.1. for a **proposed investment** that is necessary to meet the reliability standard set out in clause 4.2 of the **grid reliability standards**:

4.1.1. the **proposed investment** maximises the **expected net market benefit** or minimises the **expected net market cost** compared with a number of **alternative projects**; and

²⁵ April 2006 Draft Decision, paragraphs 6.3.2-6.3.3, pages 31-32.

²⁶ Clause 12.

4.1.2. *if sensitivity analysis is conducted, a conclusion that a **proposed investment** satisfies clause 4.1.1 is sufficiently robust having regard to the results of that sensitivity analysis;*
or

4.2. *for any other **proposed investment**:*

4.2.1. *the **proposed investment** maximises the **expected net market benefit** compared with a number of **alternative projects**;*

4.2.2. *the **expected net market benefit** of the **proposed investment** is greater than zero; and*

4.2.3. *if sensitivity analysis is conducted, a conclusion that a **proposed investment** satisfies clauses 4.2.1 and 4.2.2 is sufficiently robust having regard to the results of that sensitivity analysis.”*

5.4.4 The remainder of schedule F4 contains the methodology for applying the GIT (clauses 5 to 17) and the definitions to be used (clauses 18 to 32).

5.5 Methodology for applying the GIT

5.5.1 There are two main aspects to the analysis in the Commission’s GIT application: power systems analysis and the quantification of costs and benefits.

Power systems analysis

5.5.2 System Studies Group New Zealand Limited (**SSG**) carried out power systems analysis to verify that each of the alternatives proposed by Transpower, as well as the Proposal, reflected GEIP and met the GRS. This is required because clause 19.3 states that the alternative projects used in the GIT application must each be “*reasonably likely to proceed if neither the proposed investment nor any other alternative project proceeds...*”, and they could not meet that requirement without meeting the criteria required for the Commission to approve them under section III of part F.

5.5.3 The Commission’s power systems analysis results are detailed in the SSG report, which is available on the Commission’s website.

5.5.4 The power systems analysis resulted in the conclusion that meeting the more onerous “*N-G-1*”²⁷ security standard appeared to be economic after a cost trade-off was made with the reliability benefits when considering the Proposal.

²⁷ “N” refers to a number of transmission facilities, “-G” refers to a generating unit being out of service, and “-1” refers to “single credible contingency event” as defined in part A of the Rules. In the Auckland region, the most onerous N-G-1 contingency refers to a simultaneous outage of Otahuhu B and one of the largest transmission circuits between Whakamaru and Otahuhu.

Transpower agrees, although it reached this conclusion on the basis of a different analysis, and without conducting a probability analysis.²⁸

Quantifying costs and benefits

- 5.5.5 The second aspect of the Commission's GIT analysis involved quantifying the various market costs and benefits of both the Proposal and the alternative projects that are required to be taken into account in the application of the GIT.
- 5.5.6 There is no requirement in the Rules for the Commission to use any particular set of costs in assessing the Proposal. What is required is for the Commission to be reasonably satisfied that the Proposal maximises the expected net market benefit or minimises the expected net market cost when compared with a number of alternatives. This means that the Commission must be satisfied that the costs used are reasonable in order to enable a robust application of the GIT.
- 5.5.7 The GIT requires the Commission to estimate a wide range of market costs and benefits, and, in view of the uncertainties involved, the GIT uses net market benefits and net market costs that are "expected" values.
- 5.5.8 The net market benefits or net market costs for a proposed investment and for each alternative project must be determined having regard to a number of reasonable future states of the electricity industry (market development scenarios or **MDS**).²⁹
- 5.5.9 The probabilities assigned to indicate the likelihood of each MDS occurring are applied to "weight" the net market benefits or net market costs.
- 5.5.10 The sum of the probability-weighted net market benefits (or net market costs) for a proposed investment represents the expected net market benefit (or expected net market cost). Likewise, for an alternative project, the sum of its probability-weighted net market benefits (or net market costs) is the expected net market benefit (or expected net market cost) for that project.³⁰
- 5.5.11 The Commission emphasises that identifying costs and benefits to be quantified involves uncertainty and requires judgments, often complex, to be made as to the estimated costs and benefits.
- 5.5.12 The Commission, as a decision-making body, is required to assimilate information and form a view on a wide range of costs and benefits. In some instances, the Commission has received different views expressed by Transpower, Transpower's external consultants, the Commission's own staff and external advisors, regarding what is the appropriate value to attribute to a particular cost or benefit.

²⁸ Application for Approval, paragraph 187, page 43.

²⁹ Clause 5. For the reasons outlined in paragraph 6.3, the Commission considers that the MDS comprise only one scenario.

³⁰ Clause 26.

- 5.5.13 The Commission Economic Report summarises the range of information received by the Commission. The Commission's approach to the range of available information has resulted in:
- (a) the Commission including certain inputs or assumptions if it is satisfied that the range of information provided enables it to come to a sufficiently robust view as to the relevant input or assumption; or
 - (b) the Commission disregarding some suggested inputs or assumptions where the level of uncertainty associated with the relevant input or assumption would be fatal to a robust application of the GIT. For example, a possible reliability benefit in favour of the 220kV option relating to grid resilience after a second 220kV line is constructed has been disregarded for this reason. Similarly, the claimed business confidence benefit in favour of the Proposal has not been included.
- 5.5.14 Finally, although the GIT is designed to find a precise number representing the expected net market benefit, or expected net market cost, for a proposed investment and each alternative project, the number may give a false sense of precision and certainty, given the number of judgments required and the uncertainty inherent in the inputs and assumptions adopted.
- 5.5.15 Despite this uncertainty, the Commission is required to make a decision on the information before it. Section 7 sets out the costs and benefits adopted by the Commission in order to make a decision on the Proposal.

6 ANALYSIS PARAMETERS

6.1 Introduction to GIT analysis parameters

6.1.1 Within the GIT methodology, the Commission has discretion to determine a number of the analysis parameters for the purpose of applying the GIT. This section sets out the analysis parameters for the GIT as determined, by majority, by the Commission.

6.1.2 One Commissioner differs from the majority in respect of some of the analysis parameters. The minority views of that Commissioner are set out in section 10 of this document.

6.2 Analysis period (clauses 23 and 27)

6.2.1 Clause 23 (definition of “cost”) and clause 27 (definition of “market benefit”) require that the Commission calculate the present value of costs and benefits of a proposed investment or alternative project:

*“...over a period of 20 years from the commissioning date (unless significant **market benefits or costs** are expected to arise from the **proposed investment or alternative project** after that time, in which case the then-present value of any future benefits may also be included in the **market benefit of the proposed investment or alternative project**)”.*

6.2.2 The Commission interprets clauses 23 and 27 as meaning that the Commission:

- (a) must take into account the present value of costs and benefits of the Proposal and each alternative project that arise over the period of 20 years that commences with the commissioning of the Proposal or relevant project; and
- (b) may, if significant market benefits or costs are expected to arise after that time, include those market benefits or costs in the NPV analysis by calculating the “then present value” of those future costs and benefits. As set out in the April 2006 Draft Decision, the Commission has termed these costs and benefits “Terminal Benefits” and “Terminal Costs” respectively, and calculates them using a “terminal benefit calculation”.³¹

6.2.3 In the Proposal, Transpower has analysed the costs and benefits of the Proposal over a 29-year period, from 2013 (the anticipated commissioning date allowing for 2 years’ delivery risk), to 2042. Transpower states that it chose to extend the analysis period by nine years (to 2042) because this date is when, approximately, the thermal capacity of the Proposal is exhausted and the next

³¹ April 2006 Draft Decision, paragraphs 7.3.85-7.3.91, pages 80-81.

new line would have to be considered.³² Transpower then performs a terminal benefit calculation at 2042.

- 6.2.4 Transpower has also advised the Commission that it chose to extend the analysis period to 2042 to remedy a “terminal benefit anomaly” that it encountered when conducting a terminal benefit calculation at 2033, compared with 2042. The Commission has conducted a number of analyses using Transpower’s information, but no terminal benefit anomaly has been found.
- 6.2.5 Calculating costs and benefits over a 20 year period and then conducting a terminal benefit calculation, should give the same result as adopting a 29-year analysis period and calculating a terminal benefit calculation, provided all inputs and assumptions are the same.
- 6.2.6 The Commission has adopted an analysis period of 20 years (from 2013 to 2033) as this is most consistent with the Rules.
- 6.2.7 Accordingly, the Commission’s interpretation of the Rules and consequent adoption of a 20-year analysis period (plus terminal benefit calculation) should not be a point of difference between the Commission and Transpower if all the inputs and assumptions used in each calculation are the same.
- 6.2.8 The features of the MDS discussed below, constitute the underlying assumptions used in NPV calculations.

6.3 Market development scenarios (clauses 5, 6 and 28)

- 6.3.1 As the manner in which new generation will enter the New Zealand electricity market is uncertain, the GIT requires the costs of a proposed investment and its alternative projects to be estimated for a number of MDS (reasonable future states of the electricity industry).
- 6.3.2 MDS include estimated future demand growth, generation investments and transmission investments.
- 6.3.3 The MDS used in applying the GIT must be those scenarios the Commission outlined in the statement of opportunities (**SOO**) unless the Commission has determined that others are more appropriate.³³
- 6.3.4 In July 2005, the Commission prepared and published the first SOO (**Initial SOO**), which remains current.

Scenarios in the Initial SOO must be extended

- 6.3.5 The MDS in the Initial SOO provide possible future states of the electricity system to 2025. However, the GIT requires costs and market benefits to be

³² Proposal, Attachment E, Transpower Economic Report, (**Transpower Economic Report**), section 2, page 7.

³³ Clause 6.1.

assessed over a period of 20 years from the estimated commissioning date of the proposed investment/alternative project.

- 6.3.6 As set out in paragraph 6.2.6 above, the analysis period in relation to the Proposal is 2013 to 2033. Accordingly, the Commission must at least extend the MDS in the Initial SOO by 8 years, to 2033, which is 20 years after the anticipated commissioning date (including a delivery risk allowance) of the Proposal. For the purpose of carrying out the terminal benefit calculation, it is necessary to further extend the scenarios to the point at which the terminal capacity of the transmission line to which the Proposal relates is exhausted.³⁴
- 6.3.7 The Commission has also considered whether any other features of the MDS require adjustment. Each key feature of the MDS is considered below.

Demand forecast

- 6.3.8 The Commission developed and published its view of national and regional demand projections for a 20-year period (in this case to 2025) and set them out in sections 6.5, 6.6 and Appendix 4 of the Initial SOO. The projections are based on annual periods from 1 April to 31 March, starting on 1 April 2005, and set out the Commission's projection of total electricity taken off the national transmission grid (sum of all demand at the grid exit points), in GWh per annum.
- 6.3.9 The Commission's demand forecast is based on econometric modelling techniques, which are more suited to long-term electricity demand forecasting than other techniques such as time series analysis based on the extrapolation of historic trends.
- 6.3.10 A key requirement of the Initial SOO is to enable identification of opportunities for investment in transmission and transmission alternatives, and this has resulted in the Commission choosing grid off-take demand as the point of reference for its demand forecasts. The forecasts are built around the three main demand sectors, each of which has different characteristics:
- (a) residential;
 - (b) commercial and light industrial; and
 - (c) heavy industrial (usually directly connected to the grid).

Generation scenarios

- 6.3.11 In the Initial SOO, the Commission identifies five possible generation scenarios in New Zealand to 2025.³⁵ These scenarios were developed to reflect the numerous inputs that may shape generation development over the 20-year

³⁴ Transpower Economic Report, page 7.

³⁵ Initial SOO, pages 73-90.

horizon, such as energy policy, fuel supply projections, and technological trends.

- 6.3.12 This backdrop has formed the basis for selecting a representative set of modelled generation projects appropriate for the possible futures. The five scenarios adopted in the Initial SOO are described as:
- (a) gas thermal;
 - (b) coal thermal;
 - (c) large hydro;
 - (d) renewables; and
 - (e) low demand.
- 6.3.13 Transpower has used the same generation scenarios from the Initial SOO, but has extended the period that they relate to until 2042, and assumed the same total amount of generation is introduced in the Upper North Island between 2005 and 2042 as the Initial SOO assumes over the 20 years between 2005 and 2025.³⁶
- 6.3.14 Since Transpower submitted the Proposal, the Minister of Energy has published the GPS. The Government also released a draft New Zealand Energy Strategy in December 2006.³⁷
- 6.3.15 Both of those documents emphasise the importance of renewables, and anticipate changes in demand in the future.
- 6.3.16 In light of those documents, and the requirement in the GIT that the MDS used to analyse an investment in a GUP must be “reasonable future states of the electricity industry”, the Commission considers that the MDS in the Initial SOO are no longer appropriate.
- 6.3.17 Instead, the Commission considers that a variant of the “low demand” scenario is most appropriate. In that scenario, the Commission anticipates the introduction of one new 380MW thermal generating unit in the Upper North Island some time between 2013 and 2042. This approximates the 1.2 generating units that is the probability-weighted average of the number of generators in the scenarios in the Initial SOO.
- 6.3.18 The Commission considers that there is insufficient certainty of there being more than one new thermal generating unit in the Upper North Island to include more than one in the MDS used in analysing the Proposal.

³⁶ Transpower explains its rationale for this approach in section 8 of its Supplementary Information report and in section 2 of the Transpower Economic Report.

³⁷ This document is available on the MED website: www.med.govt.nz

- 6.3.19 In coming to that view, the Commission has had regard to the draft New Zealand Energy Strategy as well as a recent letter³⁸ from the Minister of Energy to all of the major generating companies. In that letter, the Minister put those companies on notice that the Government is considering a range of mechanisms that may be used to “*control, prevent or price carbon emissions from additional fossil fuel energy production in the stationary energy sector*”.
- 6.3.20 The Commission’s choice of the revised scenario anticipates a limited amount of new thermal generation developing in the Upper North Island. Even in a predominantly renewables future, the Commission considers that there is some prospect of additional thermal generation in the Upper North Island as “firming” generation.
- 6.3.21 Finally, in coming to the above conclusion, the Commission has not overlooked clauses 6.2 and 6.3, which require the number and probability of MDS to be as set out in the Initial SOO.
- 6.3.22 The Commission considers that, if it strictly complied with clauses 6.2 and 6.3, given its views on the reasonable future states of the electricity industry, it would simply adopt five identical generation scenarios and assign a 20% probability to each scenario, or, alternatively, it would adopt scenarios which differed only in relation to the year in which the additional thermal generation unit is introduced. Either approach would strictly comply with clauses 6.2 and 6.3, but would produce exactly the same result as assigning a 100% probability to the single scenario that it considers the only useful scenario in this context. The Commission has therefore produced its results on the basis of one generation scenario (reduced demand in areas other than in Auckland) and assigned it a probability of 100%.

Transmission investments

- 6.3.23 Appendix 5 of the Initial SOO sets out the committed and modelled projects that comprise the transmission investments in the Initial SOO base case.
- 6.3.24 Consistent with the Commission’s approach to modelling the Original Proposal, the Commission included additional committed and modelled projects as part of its analysis of the Proposal. These additional projects were added primarily for two reasons:
- (a) in respect of committed projects, to more accurately reflect the current situation in which Transpower has applied for, and the Commission approved, a number of additional transmission investments under the transitional provisions³⁹ which will have a positive impact on security of supply in Auckland; and

³⁸ Letter from the Minister of Energy “Re: New Zealand Energy Strategy”, 19 December 2006.

³⁹ For details of interim grid expenditure approved to date, see <http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/gdp/Interim-grid-exp.pdf>

- (b) in respect of modelled projects, to reflect the additional investments that Transpower may be likely to make in the future to ensure security of supply and meet the GRS until the end of the 20-year analysis timeframe.

6.3.25 The additional modelled projects are those proposed by Transpower in the Proposal, with some minor adjustments. Further discussion of the modelled projects used in the analysis of the Proposal is contained in paragraphs 7.1.7 to 7.1.12 of this document.

Draft 2007 SOO

6.3.26 The Commission is in the process of developing the Draft 2007 SOO, and has consulted on the grid planning assumptions (**GPAs**) that underlie the Draft 2007 SOO.

6.3.27 The Commission has considered whether it would be appropriate to adopt the scenarios in the GPAs, in particular the demand forecasts and generation scenarios anticipated by the GPAs, as the MDS used for the purpose of analysing the Proposal.

6.3.28 The Commission determined that it would not be appropriate to do so in this case. Transpower prepared and submitted the Proposal on the basis of the MDS in the Initial SOO. The Commission determined that it would not be appropriate, part way through the process, to adopt the scenarios in the GPAs that underlie the Draft 2007 SOO. The Draft 2007 SOO is yet to be consulted on, and may change.

6.3.29 In addition, as set out above, the Commission is satisfied that the MDS it proposes to adopt in order to analyse the Proposal under the GIT meets the requirements set out in the GIT that the MDS represents a reasonable future state of the electricity system.

6.3.30 However, the Commission has included the demand forecasts in the Draft 2007 SOO as a sensitivity in applying the GIT to the Proposal.

6.4 Base case and reference case (clauses 5, 8 and 20)

6.4.1 The GIT requires the market benefits and costs of a proposed investment or alternative project to be determined for each MDS for the future with that proposed investment or alternative project by comparing that MDS with the corresponding MDS developed for the base case.⁴⁰

6.4.2 Appendix 5 of the Initial SOO includes transmission data to define the base case MDS required for application of the GIT and the GRS.⁴¹ The “transmission data” comprises a number of augmentation projects, including the Original Proposal.

⁴⁰ Clause 5.

⁴¹ Appendix 5, Initial SOO.

- 6.4.3 Since the development of the Initial SOO, the Original Proposal has been considered and rejected by the Commission under section III of part F. Transpower has also advised that it no longer wishes to progress the Original Proposal.
- 6.4.4 Accordingly, the Commission does not consider that it is reasonable to adopt as a base case a scenario that includes the Original Proposal. The Commission must therefore determine a new base case in order to consider and apply the GIT to the Proposal.
- 6.4.5 The Commission faced the same issue (the need to identify a new base case) in relation to its consideration of the Original Proposal. In the April 2006 Draft Decision, the Commission considered and rejected an “unserved energy” option as a base case in relation to the Original Proposal.⁴²
- 6.4.6 While the Commission stated in the April 2006 Draft Decision that the most appropriate option for a base case would be a generation-only option, it did not further consider the generation-only option because the tools to ascertain the costs associated with that option had not been developed to a sufficient degree of accuracy for GIT application.⁴³
- 6.4.7 In order to analyse the Original Proposal, the Commission adopted a “reference case” to compare differences in net market benefits between the Original Proposal and each of the alternative projects, thereby comparing the project with the base case indirectly rather than directly.
- 6.4.8 In the Transpower Economic Report,⁴⁴ Transpower states that it has adopted the Commission’s approach in the April 2006 Draft Decision to analysing the Proposal by using a reference case to analyse the Proposal. Transpower recommends that one of the alternative projects proposed, option 1 (the alternative project comprising a 220kV transmission line), be used as a reference case. Transpower states that this is “*akin to establishing a “business as usual” reference case, since the existing grid already comprises 220kV as its core voltage*”.⁴⁵
- 6.4.9 The Commission agrees that option 1 should be adopted as a reference case for the purposes of assessing the market benefits and costs of the Proposal and any alternative projects adopted.
- 6.4.10 For the reasons outlined in the April 2006 Draft Decision, the Commission does not consider that the unserved energy option is an appropriate base case in relation to applying the GIT to the Proposal in this case.
- 6.4.11 In relation to the generation-only option, since the April 2006 Draft Decision more information has become available and further analysis has been carried

⁴² April 2006 Draft Decision, section 6.7, page 39.

⁴³ Ibid.

⁴⁴ Section 2.4, pages 11-13.

⁴⁵ Ibid, section 2.4.3, page 12.

out regarding the credibility and likelihood of new generation being constructed in the Auckland region to supply growing demand in that region.

- 6.4.12 However, the tools to ascertain the costs associated with the generation-only option remain largely undeveloped and will not be developed sufficiently for at least another 6 months to be confident of a robust application of the GIT.
- 6.4.13 Accordingly, the Commission has adopted option 1 (the 220kV transmission line) as the reference case for the application of the GIT to the Proposal.

6.5 Value of unserved energy (clauses 8.3.4 and 8.4.3)

- 6.5.1 If customers are deprived of their electricity supply, they are likely to incur an economic cost while that supply is unavailable. The anticipated amount of electricity that customers would have used but were not able to is called “expected unserved energy”.
- 6.5.2 The GIT allows for a value to be placed on consequential unserved energy and states that those value(s) will be:
- (a) the value or values published by the Commission for this purpose from time to time; or
 - (b) if no such value or values is published by the Commission, \$20,000/MWh.
- 6.5.3 In the explanatory paper about the GIT that was published on 3 December 2004⁴⁶ (**GIT Explanatory Paper**), the Commission set out reasons why this default value of \$20,000/MWh was chosen.
- 6.5.4 In the Initial SOO, the Commission adopted a value of \$20,000/MWh. In its Proposal, Transpower has also valued unserved energy at \$20,000/MWh.
- 6.5.5 The Commission confirms that the value of unserved energy will be \$20,000/MWh for the purposes of assessing the Proposal under the GIT. The Commission regards that value as published in December 2004 as a real economic parameter, which should be escalated according to inflation assumptions to retain a constant real value.
- 6.5.6 In its Proposal, Transpower has used sensitivities of \$10,000 and \$40,000 on the basis of a report from Castalia Strategic Advisors (**Castalia**)⁴⁷ to Transpower that recommends using a value of \$41,000 rather than \$30,000 to value unserved energy in the Auckland region.
- 6.5.7 Clause 17.5 sets the upper and lower bounds of sensitivity analysis for the value of unserved energy at \$30,000/MWh and \$10,000/MWh respectively, but also allows the Board to publish other values of unserved energy to be used in the sensitivity analysis.

⁴⁶ See <http://www.electricitycommission.govt.nz/opdev/transmis/pdfsconsultation/GITExplanatoryDocument.pdf>

⁴⁷ Proposal, Attachment M, Assessment of the Value of Unserved Energy, Report to Transpower, August 2006.

- 6.5.8 The Commission is not convinced that the Castalia report provides a sound basis for adopting an alternative upper bound for use in the Commission's sensitivity analysis. Castalia has simply averaged a selective sample of Australian and United States "value of lost load" estimates, and has used New Zealand data to derive the averaging weights.
- 6.5.9 In any event, the value of unserved energy is not a critical analysis parameter in the context of applying the GIT to the Proposal within the analysis period. This is because the nature of the Proposal and the alternatives considered by Transpower mean that there is very little scope for unserved energy to change the evaluation of ranking.
- 6.5.10 Accordingly, the Commission has used the upper and lower bounds set out in clause 17.5 in carrying out its sensitivity analysis.

6.6 Net present value or real options analysis (clause 13)

- 6.6.1 Clause 13 requires that either standard net present value (**NPV**) analysis or real options analysis must be applied in assessing the expected net market benefit of a proposed investment or alternative project.
- 6.6.2 Traditional NPV analysis calculates the NPV of a proposed investment based on the benefits less the costs. Real options analysis attempts to value the flexibility that is inherent in many investment projects, which allows investment plans to be changed or abandoned as new information arrives. By responding appropriately to such new information, decision-makers are able to take advantage of new opportunities.
- 6.6.3 In the April 2006 Draft Decision, the Commission explained why true real options analysis is not practicable for transmission investment analysis.⁴⁸
- 6.6.4 In its Proposal, Transpower has used standard NPV analysis and used a Monte Carlo NPV analysis to approximate the value of any real options. This is consistent with the Commission's approach in the April 2006 Draft Decision.
- 6.6.5 The Commission agrees that a standard NPV analysis approach is appropriate for analysing the Proposal and has implemented a Monte Carlo procedure, overlaid on the NPV analysis, to capture the uncertainty that exists regarding demand growth rates and generation locating in the Auckland region.
- 6.6.6 Incorporating these uncertainties impacts on all costs and benefits assessed by the Commission, as they impact on the timing that the cost or benefit is incurred during the analysis period to 2033. The results presented in section 7 of this document incorporate the final averaged results of the Monte Carlo/NPV modelling procedure.

⁴⁸ April 2006 Draft Decision, section 6.9, pages 41-42.

6.6.7 The Commission considers four real options exist that may materially influence the evaluation of the Proposal:

- (a) *Real option value of flexible investment timing*: By virtue of delaying an investment, and/or staging an investment, a real option is created. This is because an option exists to change or further modify investment plans if demand growth turns out to be lower than expected, or if local generation is constructed. This has been assessed by the Commission and is referred to as the “real option value of flexible investment timing”.
- (b) *Technology option value*: Staged investments may be modified to utilise new technology if it becomes available (eg HVDC with 350kV polyethylene cable or gas-insulated line). This option value has not been calculated by the Commission, as it is not considered readily quantifiable.
- (c) *Real option value of excess transmission capacity*: Excess transmission capacity potentially enables generation investments to respond quickly to new generation opportunities. While the candidate alternative projects (discussed in section 6.9) and the Proposal result in similar transmission capacities into the Auckland region, the Proposal would provide the option to more easily create additional capacity compared with these alternatives. The Commission was not able to separately estimate this option value and accordingly it has not been included in the GIT analysis.
- (d) *Optionality of 400kV-capable line*: If a 400kV-capable line is constructed, it would preserve the option of extending a 400kV “backbone” for the transmission grid through the North Island. If a 220kV-rated line is constructed, this option would be closed off, because it would then be uneconomic to build such a line during the analysis period. Other than taking into account the transformer rationalisation benefit discussed in paragraphs 7.3.70 to 7.3.77, the Commission has not separately estimated this option value.

6.7 Discount rate (clause 14)

6.7.1 The GIT requires the discount rate to be used in all NPV calculations to be:

- (a) a discount rate determined by the Commission; or
- (b) if the Commission has not determined a rate, equivalent to a pre-tax real rate of 7%.

6.7.2 In the GIT Explanatory Paper, the Commission set out reasons why a default value of 7% was chosen.

6.7.3 Transpower has applied a discount rate of 7% in its Proposal. However, Transpower refers to advice received from Castalia,⁴⁹ which concludes that

⁴⁹ Proposal, Attachment L, Discount Rate for the Grid Investment Test, Report to Transpower, August 2006.

there is a strong argument for use of a discount rate in the range of 2.72% to 4.18% in the GIT.⁵⁰

6.7.4 Transpower has, therefore, also applied a discount rate of 4% as a lower bound sensitivity on the basis of the Castalia advice. Transpower has also used a rate of 10% as an upper bound sensitivity.

6.7.5 The Commission considers that 7% is an appropriate discount rate to be applied to NPV calculations in this application of the GIT and has therefore applied that rate to the NPV analysis. The Commission agrees with Transpower that this discount rate should be subject to a sensitivity analysis by applying the alternative rates of 4% and 10%.

6.8 Competition benefits (clauses 10 and 22)

6.8.1 Competition benefits are defined as:⁵¹

*“the direct or indirect effects of greater competition between **generators** resulting from a **proposed investment** or **alternative project**, including as a result of the associated introduction of additional **demand-side** management initiatives, on:*

*22.1. the cost of **dispatch**;*

*22.2. forecast **demand growth**; and*

*22.3. the timing of **modelled projects**.”*

6.8.2 Competition benefits may be included in the market benefits of a proposed investment or alternative project if the Commission reasonably considers this appropriate, *provided* the competition benefits can be separately identified and calculated.⁵²

6.8.3 This means that if a competition benefit cannot be separately identified and calculated, the Commission is not permitted to take it into account.

6.8.4 Transpower considers that the Proposal has competition benefits⁵³ because, in Transpower’s view, the Proposal has significantly more capacity that can be released at relatively short notice compared with the alternatives.⁵⁴

6.8.5 However, the Commission considers that the “competition benefits” claimed by Transpower are in fact not competition benefits within the definition in the Rules, but rather are capacity related perception benefits, and, as such, those benefits have been considered as part of the Commission’s application of the GIT, as set out in section 8.

⁵⁰ Transpower Economic Report, section 2.6, page 14.

⁵¹ Clause 22.

⁵² Clause 10.

⁵³ Application for Approval, section 6.3.3, page 54.

⁵⁴ Transpower Economic Report, section 2.7.10, page 18.

- 6.8.6 During the Comments Period, the Commission received comments from the Energy Centre, which is part of the University of Auckland. The Energy Centre raises two possible competition benefits. The first relates to minimum transfer capacity, and the second relates to the perception of additional capacity.
- 6.8.7 In relation to minimum transfer capacity, the Energy Centre states that a review of recent economic literature suggests that, in an electricity market situation, unused transmission capacity may well be very useful in generating competition benefits, even if there is no absolute transmission constraint in an engineering sense. The Energy Centre states that a major conclusion is also that the need for transfer capacity (optimum capacity) in a deregulated electricity market will often be higher than in an centralised, controlled, environment.
- 6.8.8 However, the Energy Centre notes that modelling competition benefits of transmission capacities is highly complex, but also advises that it has embarked on modelling the minimum (surplus) transfer capacity needed to ensure a competitive outcome. The Energy Centre states that, below such a minimum capacity *“players (generators) will have an incentive to play non-competitive games, (ab)use market power, produce less at higher prices, and the outcome (equilibrium price levels) are likely to be considerably higher. In a deterministic context, any capacity above this minimum has no (competition) value.”*⁵⁵
- 6.8.9 However, the Energy Centre concludes that, due to the assumptions required to complete its preliminary modelling and the limited timeframe within which the modelling was carried out, its preliminary modelling results are *“not reliable enough (yet) to base major conclusions on”*.⁵⁶
- 6.8.10 Turning to the perception of additional capacity, the Commission agrees that a competition benefit may arise from the reduction in the exercise of market power caused by a perception of increased future certainty of capacity, or the ability to quickly release additional capacity.
- 6.8.11 However, this benefit has not been separately calculated, and accordingly, clause 10 prevents the Commission from including that possible competition benefit in the application of the GIT to the Proposal.
- 6.8.12 Transpower’s advisors, CRA International, also noted that Cournot modelling may be used to calculate competition benefits.⁵⁷ However, no such modelling had been carried out by Transpower.
- 6.8.13 The Commission has not separately identified any competition benefits (as defined) that it wishes to take into account in applying the GIT to the Proposal.

⁵⁵ Comments provided by the Energy Centre in a document entitled “Transpower’s amended North Island Supply Upgrade Application”, November 2006, section 1, page 4

⁵⁶ Ibid.

⁵⁷ Letter to Transpower from CRA International, 16 January 2007.

6.9 Alternative projects

6.9.1 Rule 13.3 contemplates that:

- (a) designated transmission customers can request that the Commission consider alternatives to Transpower's proposed reliability investments;
- (b) the Commission can ask Transpower to evaluate:
 - (i) alternative reliability investments; and
 - (ii) transmission alternatives, where Transpower possesses relevant expertise.

6.9.2 In order to assess whether the Proposal satisfies the GIT, the Proposal must have been compared with a number of alternative projects.⁵⁸

6.9.3 Clause 19 sets down the criteria for the selection of alternative projects as follows:

*“19. **“Alternative projects”** means any alternative transmission augmentation projects and **transmission alternatives** to the **proposed investment**, including any variant of the **proposed investment** that involves a non-negligible change in the timing of that **proposed investment**, that are:*

19.1 technically feasible;

19.2 reasonably practicable having regard to the matters set out in clauses 8.1 to 8.4;

*19.3 reasonably likely to proceed if neither the **proposed investment** nor any other **alternative project** proceeds and unlikely to proceed if the **proposed investment** does proceed;*

*19.4 reasonably expected to provide similar benefits, in type but not necessarily in magnitude, to relevant nodes, as the **proposed investment**; and*

*19.5 reasonably expected to enable the deferment of investment of the type contemplated by the **proposed investment** for a period of 12 months or more.”*

6.9.4 Clause 11 provides that the alternative projects used in applying the GIT must be limited to those appropriate in number and technology given the cost magnitude of the proposed investment, the complexity of the required modelling and the urgency of the proposed investment.

⁵⁸ Clause 4.1.1.

Requests that the Commission consider alternatives

6.9.5 On 24 October 2006, in accordance with rules 13.3.2⁵⁹ and 13.3.5, the Commission published Transpower's Proposal on the Commission's website and provided an opportunity for interested parties to provide written comments on Transpower's Proposal and to request that the Board consider alternatives to Transpower's Proposal. The Commission comments below as applicable on requests received.

Transpower's consideration of alternatives

6.9.6 The eight transmission options considered by Transpower included a mix of 400kV, 220kV and duplexing options from Whakamaru to Pakuranga and to Otahuhu. Transpower assessed the technical feasibility of these options, and used the criteria of diversity and capital cost to evaluate the eight transmission options, in order to create a shortlist.⁶⁰

6.9.7 Transpower then applied the GIT to a shortlist of four transmission options, and performed a limited economic analysis on the generation alternatives. The shortlist of options investigated by Transpower includes the following:

(a) generation options:

- (i) coal-fired base load generator;
- (ii) gas-fired base load generator; and
- (iii) gas or diesel-fired peaking generators;

(b) transmission options:

- (i) building a new 220kV transmission line between Pakuranga (**PAK**) and Whakamaru (**WKM**), referred to as option 1 in the Application for Approval;⁶¹ and
- (ii) duplexing of the existing Otahuhu (**OTA**) to WKM A and B lines, followed by a new 220kV transmission line between PAK and WKM, referred to as option 3 in the Application for Approval; and
- (iii) (non-qualifying alternative) duplexing the existing OTA-WKM A, B & C lines with high temperature conductor (**HTC**), referred to as option 4 in the Application for Approval.

6.9.8 Transpower's Proposal is referred to as option 2 in the Application for Approval.

⁵⁹ There are currently no designated transmission customers as defined. However, only participants (as that term is defined in part A of the Rules) can become designated transmission customers. Therefore Commission has applied this rule 13.3.2 to participants.

⁶⁰ This process is described in the Application for Approval, section 4.6, pages 21-23.

⁶¹ Transpower and the Commission have adopted this option as the "reference case", as discussed earlier

- 6.9.9 These options are discussed further below, as well as HVDC options considered and rejected by Transpower.

Transmission options

220kV option – option 1

- 6.9.10 Option 1 involves building a new 220kV double circuit transmission line between Whakamaru and Ormiston Road (south of Otahuhu) with 220kV underground cables from Ormiston Road, first at Pakuranga, and subsequently to Otahuhu.
- 6.9.11 Transpower states that the line design for any new 220kV line option “was intended to meet the intent of the (draft) GPS requirement 88E for fewer corridors of high capacity. The heaviest conductor in use on 220kV lines at present is Chukar and the line was optimised to give the greatest available capacity with this conductor for the lowest practicable implementation costs”.⁶²
- 6.9.12 Transpower states that the height of the towers associated with the proposed 220kV transmission line are up to 58 metres. Transpower acknowledges that lower tower heights are possible but states that the use of lower towers would result in a significant increase in the number of towers and therefore cost.
- 6.9.13 Option 1 is very similar electrically to the Proposal. The key distinguishing feature between the Proposal and this option is the ability for the transmission line to which the Proposal relates to be converted to 400kV operation in the future.
- 6.9.14 The Commission considers that option 1 considered by Transpower meets the requirements of clause 19 of the GIT.
- 6.9.15 Accordingly, the Commission has adopted option 1, comprising a suite of measures including the construction of a 220kV transmission line, as an alternative project (the **220kV Alternative**) for the purpose of applying the GIT to the Proposal.

Duplexing option – option 3

- 6.9.16 Transpower described its consideration of the duplexing option (option 3) in detail in sections 4.4.3 and 6.3.4 of the Application for Approval. Option 4 (duplexing using HTC technology) is a variant of option 3. The general views expressed below regarding duplexing apply equally to that option.⁶³
- 6.9.17 Transpower concludes that the NPV option 3 is \$813 million in 2006 dollars, i.e. \$125 million more (in NPV terms) than the Proposal. Transpower attributes the greater cost primarily to the following factors:

⁶² Application for approval, section 4.4.1, paragraph 54, page 18.

⁶³ The Commission's views on HTC technology are discussed separately below, under the heading “*HTC Option – option 4*”.

- (a) the degree of strengthening (and therefore additional cost) required for towers along the transmission route;
 - (b) high anticipated property-related costs; and
 - (c) relatively high losses incurred on the line.
- 6.9.18 In relation to property costs, Transpower states that “even if, in an extreme case, the property costs were considered to be zero, the GIT analysis shows that the project would still lag options 1 and 2 by approximately \$40 million”.⁶⁴
- 6.9.19 The Commission sought to review the capital costs of option 3 as a first step to considering whether that option should be included as an alternative project for the purpose of applying the GIT to the Proposal.
- 6.9.20 In particular, the Commission’s analysis reviewed various capital cost assumptions used by Transpower about the need for, and costs of, easements, undergrounding through the urban area into Otahuhu, tower and foundation strengthening works on existing towers, and re-use of the existing conductor for up to 10 years before replacement is required.
- 6.9.21 In relation to easements, in the recent case of *Fernwood Dairies Limited v Transpower New Zealand Limited* (C171/2005, Environment Court, Christchurch, 18 December 2006), the Environment Court found that Transpower’s proposed duplexing of the Roxburgh-Islington A line over Fernwood’s farm land did not constitute “injurious affection”, and accordingly duplexing of the line in that case was “maintenance” in terms of the Act.⁶⁵
- 6.9.22 Although it is necessary to assess whether duplexing a line over a particular property leads to injurious affection on a case by case basis, the *Fernwood Dairies* case is an example of a “maintenance” upgrade under the Act that did not require Transpower to obtain an easement. However, the ruling also indicated that, although a full easement may not be required, affected land owners could claim compensation due to the fact that an additional conductor may affect land values.
- 6.9.23 Therefore, although duplexing may not necessitate additional/significant easement costs, compensation may nevertheless be payable to a land owner.
- 6.9.24 The Commission’s modelling of different cost assumptions showed that the difference in the expected net market cost of the Proposal and the expected net market cost for option 3 may lie between \$19 million and \$126 million in favour of the Proposal. That is, even adopting assumptions very favourable to option 3, the analysis shows that the Proposal minimises expected net market cost compared with that option.

⁶⁴ Application for Approval, section 6.3.4, paragraph 256, page 56.

⁶⁵ If injurious affection is caused, it is necessary to obtain an easement. On the other hand, the Act allows Transpower to carry out maintenance on existing lines.

- 6.9.25 The Commission is concerned that the uncertainties associated with the cost of option 3 would mean that, if the option 3 was included as an alternative project for the purposes of applying the GIT, the GIT analysis would be unreliable due to these uncertainties.
- 6.9.26 The Commission therefore determined not to include the option 3, the duplexing option suggested by Transpower, as an alternative project for the purposes of its analysis and decision-making.

HTC option – option 4

- 6.9.27 Transpower's option 4 is a variation of option 3, in that it proposes duplexing the Otahuhu-Whakamaru A and B lines, but with HTC rather than "twin Goat" (a type of conductor). The Commission's views on duplexing are set out above. This section covers the Commission's views on HTC technology.
- 6.9.28 Transpower summarises its consideration option 4 in sections 4.4.4 and 6.3.5 of the Application for Approval. Transpower has also provided a more detailed consideration, particularly of the costs of option 4, in its report "*Attachment G: High Temperature Conductor: Technical Analysis of using High Temperature Conductor for Duplexing the OTA-WKM A&B and Uprating OTA-WKM C Lines*".
- 6.9.29 Finally, Attachment I of the Proposal contains some discussion regarding the possible partial use of HTC along the WKM-OTA A and B lines to reduce property costs. Transpower considered the use of HTC along nine sections of the WKM – OTA A and B lines route, totalling 70 route kilometres.⁶⁶ Transpower estimates that the net conductor cost increase over duplexing with twin Goat would be \$31.5 million.
- 6.9.30 Transpower concedes that while the HTC may be used in areas where visual impact issues may trigger injurious affection, increased electromagnetic field due to higher possible line currents may by itself trigger an injurious affection. This issue has yet to be sufficiently legally tested and accordingly there is considerable doubt regarding costs, particularly with regard to property, whether HTC is implemented or not. The recent *Fernwood Dairies* case, discussed above, gives the Commission some comfort that an increase in electromagnetic field and visual impact does not automatically constitute injurious affection. Instead these issues need to be addressed on a case by case basis.
- 6.9.31 Transpower concludes that option 4 is a non-qualifying alternative because it does not consider that a line using HTC could be built within the required timeframe. However, due to the amount of public interest in HTC, Transpower carried out a simplified economic analysis of this option. Transpower's economic analysis concludes that the HTC option is not competitive.⁶⁷

⁶⁶ Proposal, Attachment I, Otahuhu-Whakamaru A & B Duplexing, page 12.

⁶⁷ Application for Approval, section 4.7.2, paragraph 109, page 25.

- 6.9.32 One additional issue is that Transpower has no construction or operational experience with this technology.
- 6.9.33 A number of comments received (including by HTC manufacturer, 3M) referred to HTC as an alternative. In particular, 3M stated that this technology had been extensively tested overseas with numerous commercial applications.⁶⁸
- 6.9.34 The Commission does not consider that there is any overseas precedent to draw on for the use of HTC over the long distances required in this case.
- 6.9.35 In addition, on the basis of the information the Commission has received to date, the use of HTC could lead to higher losses. This would be a significant factor against the use of HTC.
- 6.9.36 In summary, the Commission does not consider that any new information has arisen in comments that would cause the Commission to request Transpower carry out any further investigation of HTC as an alternative.
- 6.9.37 Further investigation would need to be comprehensive and this could take a substantial amount of additional time, particularly if Transpower were to carry out its own testing of the technology.
- 6.9.38 In light of the need to make a decision on the Proposal before it, the Commission considers that such analysis is not possible in a timeframe that would enable the Commission to make a timely decision on the Proposal. Accordingly, the Commission has not further considered the HTC option investigated by Transpower.

HVDC options

- 6.9.39 Transpower describes its consideration of HVDC options⁶⁹ in detail in section 4.7 of the Application for Approval, and concludes that an HVDC option should not be considered as an alternative project for the purpose of applying the GIT to the Proposal. Transpower's reasons for its conclusion include:
- (a) Moving one pole of the existing link to Auckland would require either construction of a new line or the conversion of existing 220kV circuit:
 - (i) Transpower considers that converting the existing lines to HVDC *“is costly, could increase congestion on the 220kV grid, and potentially restrict the ability to provide for both southward transfers and the Wellington load”*; and
 - (ii) Transpower considers that *“the time taken to consent a new HVDC line and the comparative costs of building a line from Wellington to Auckland...rule this option out”*; and

⁶⁸ A copy of 3M's comments is available on the Commission's website.

⁶⁹ Application for Approval, section 4.7, pages 23-24.

(b) It would reduce the ability to make use of opportunities for connection of renewable generation in the lower and central North Island:

(i) Transpower considers that converting the existing lines to HVDC operation would reduce the opportunities for renewables to connect to the 220kV grid (because of the reduced HVAC capacity); and

(ii) Transpower also considers that connection to HVDC is expensive due to the costs of the converter stations.

6.9.40 Essentially, Transpower considers that the construction of a new HVDC line from Wellington to Auckland, or the conversion of existing 220kV lines to HVDC, would be unlikely to proceed in the timeframe required. Therefore, Transpower does not consider that an HVDC option qualifies as an alternative project under clause 19.3.

6.9.41 The Commission agrees that the construction of a new line or modification of the 220kV grid to support HVDC would not be likely to proceed by 2011. However, such work may be possible in a slightly longer timeframe, and further, more detailed, investigation could be carried out to analyse Transpower's views of the HVDC option.

6.9.42 A number of comments received during the Comments Period referred to HVDC as an alternative. However, the Commission does not consider that any new information has come to light that would cause the Commission to request Transpower to carry out any further investigation of HVDC options.

6.9.43 In addition, the Commission considers that it would not be practicable to carry out detailed analysis on the HVDC options within a timeframe that would enable the Commission to make a timely decision on the Proposal.

Generation options

6.9.44 Transpower considered three non-transmission alternatives:

(a) 155MW Open Cycle Gas Turbine (**OCGT**), 3 shaft, peak load option (this is equivalent in size to the Whirinaki plant);

(b) 240MW Combined Cycle Gas Turbine (**CCGT**), single shaft, base load option; and

(c) 380MW coal fired steam turbine, single shaft, base load option.

6.9.45 Transpower's report "*Attachment K: Economic Analysis of Non-Transmission Alternatives*" explains Transpower's analysis of non-transmission options as alternative projects.

6.9.46 Transpower concludes that there are renewable options which exist and which are cheaper than both Auckland base coal and Auckland base CCGT, and

states “*there is increased benefit in adding renewable generation to the transmission reference case compared with subsidising thermal generation in Auckland to delay the investment of transmission into Auckland*”.⁷⁰

- 6.9.47 In addition to several general references to generation, including emerging technologies such as tidal power, many comments received during the Comments Period referred to new generation stations being investigated in the Auckland area such as Contact Energy’s Otahuhu C station, Genesis Energy’s proposed Rodney plant, and Mighty River Power’s proposed Marsden B station. However, none of the companies in question made any firm commitments in terms of these plants in their comments during the comments period.
- 6.9.48 The Application for Approval also includes discussion of the availability of the Whirinaki Plant, if it were moved to Auckland.
- 6.9.49 The Commission considers that it is prevented from considering a relocation of the Whirinaki Plant as an alternative project under clause 19. This is because neither the Commission or Transpower has any power to determine the location of the plant. This conclusion is consistent with clause 89 of the GPS. However the Commission records that this is the view it would take even in the absence of that clause.
- 6.9.50 Accordingly, while some of the generation options may produce greater expected net market benefits than the Proposal, the Commission is not satisfied that any of them are “reasonably likely to proceed” in terms of clause 19.3. Conversely, even if one or more of them does proceed, there is nothing to suggest that, even if the Proposal did not proceed, any of the decisions on them would be different.
- 6.9.51 Accordingly, the Commission is not aware of any generation options that meet the requirements of clause 19 and therefore has not included any generation options in applying the GIT to the Proposal.

Demand-side options

- 6.9.52 Transpower has not considered demand-side options specifically in the Proposal. Instead, Transpower states that it considers that “*demand-side management (DSM) projects are, at this stage, considered to be too small and/or too unproven in terms of reliability... given the scale and... urgent requirement [for the Proposal]*”.⁷¹
- 6.9.53 In relation to the Original Proposal, Transpower commissioned Strata Energy Consulting to carry out a study to investigate the feasibility and implementation strategy for peak load control.

⁷⁰ Proposal, Non-transmission Options Report, Executive Summary, paragraph 20, page 5.

⁷¹ Proposal, Attachment K, Economic Analysis of Non-Transmission Alternatives to Delay Transmission Investment into Auckland, section 1.2, page 7.

- 6.9.54 The Commission's Retail and Energy Efficiency workstreams are also progressing programmes that will contribute to reductions in the rate of demand growth and that identify further opportunities for load management, in particular, at peak.
- 6.9.55 The Commission acknowledges that a number of comments received during the Comments Period support demand-side options. However, at this stage, there are significant uncertainties about how much peak demand reduction can be relied on. While progress is being made with the appropriate market arrangements and metering technologies to enable more efficient load management, the Commission considers that demand-side options are not sufficiently certain at this stage for the Commission to be able to factor this information into the current decision-making process.

Concluding remarks

- 6.9.56 While a number of comments provided by various parties correctly identified that demand-side measures and embedded generation could be used to defer a major investment to allow more time for generation projects to develop, there were no submissions that identified committed measures to do so.
- 6.9.57 However, similar to the Commission's analysis in the April 2006 Draft Decision, Transpower has included the effects of embedded generation locating in Auckland over the GIT analysis timeframe, and these effects have been included in Transpower's market benefit calculations.
- 6.9.58 In addition, the effect of any demand-side measures, such as energy efficiency, solar water heating, and any changes to the transmission pricing structure which would impact on peak demand levels over the analysis period, have also been incorporated in Transpower's analysis. This has been carried out using a Monte Carlo analysis of the demand growth rates over the GIT analysis timeframe, and includes the effects of both high and low demand growth rates.
- 6.9.59 Therefore, the Commission considers that Transpower's approach, which employs models developed by the Commission in support of the April 2006 Draft Decision, has sufficiently included the impact that generation and demand-side alternatives may have on any transmission investment.
- 6.9.60 There are no requests to consider alternatives which do not canvass material already considered by Transpower in its consideration of alternatives.
- 6.9.61 The Commission has therefore determined to adopt as an alternative project the 220kV option described in the Application for Approval as option 1. This option is also the reference case, as set out in paragraph 6.4 above.
- 6.9.62 In adopting the 220kV Alternative as the only alternative against which the Proposal will be completely compared under the GIT, the Commission notes that the other candidate alternative projects, and in particular the duplexing

option, may have similar expected net market costs to either the Proposal or the 220kV Alternative. However, the Commission is satisfied that comparing the Proposal against the 220kV Alternative is the best way to assess whether the Proposal meets the requirements of the GIT.

7 ANALYSIS

7.1 Test 1 - Does the Proposal reflect GEIP in meeting the GRS? (rule 13.4.1.1)

Does the Proposal meet the GRS?

SSG analysis

7.1.1 SSG undertook a detailed power systems analysis. The first step in the analysis was to establish when the Proposal or each alternative project considered by Transpower, was required in order to meet demand in the Auckland region. The Commission then considered when the various modelled projects associated with each of the Proposal and alternatives were required, in order to enable the Commission to analyse the future costs and benefits likely to be associated with each of the Proposal and relevant alternative.

Application of the GRS

7.1.2 In the case of the Proposal (and any options for supply to the Auckland region), a high level of reliability is justified using the Economic Reliability Standard in the GRS. To approximate this effect in a deterministic manner, the need date for the Proposal and each option considered by Transpower was determined using an *N-G-1* approach and demand forecast levels set at 10% probability of exceedance. These results, while useful, are not relied on to establish whether or not the Proposal meets the GRS. This is because the Economic Reliability Standard is applied in the GIT analysis.

Transfer limits analysis

7.1.3 In order to facilitate the Commission's economic modelling, SSG determined the grid transfer limits for various combinations of the Proposal, candidate alternative projects, and modelled projects. In addition, SSG analysed the resulting investment streams to determine the ultimate thermal capacity for the purposes of calculating Terminal Benefits.

Review of losses

7.1.4 In order to facilitate the Commission's economic modelling, SSG determined the electrical loss characteristics for various combinations of the Proposal, candidate alternative projects, and modelled projects.

Need for constrained-on generation

7.1.5 SSG reviewed whether there was likely to be a significant need for constrained-on generation, as Transpower has suggested that this should be considered in applying the GRS.

Further analysis not required

7.1.6 SSG recommended that the Commission rely on SSG's earlier analysis of the Original Proposal, because results of re-running such analysis were highly unlikely to be significantly different. In particular, SSG relied on its earlier modelling of:

- (a) short-circuit analysis;
- (b) dynamic voltage stability analysis;
- (c) generation outages and maintenance windows; and
- (d) transient stability analysis.

Modelled projects

7.1.7 In modelling the Proposal, Transpower included a number of additional investments as modelled projects. These projects are described in Transpower's "Technical Assessment of Modified Options".⁷² This reflects that the Proposal should not be considered in isolation, and that, since the time the Initial SOO was published, Transpower's planning has further developed.

7.1.8 While the modelled projects proposed by Transpower have not been submitted by Transpower for approval, the Commission considers that, as adjusted in the manner discussed below, they are all feasible and sufficient to meet the requirements of the GRS.

7.1.9 The stated need date for each modelled project is indicative only, because the actual date a modelled project is introduced by the NPV model used by Transpower and the Commission depends on the outcome of variation in demand and generation sampled in each Monte Carlo draw.

7.1.10 Finally, the modelled projects represent possible future states of the electricity system. They cannot necessarily be regarded as optimal, and it is possible that other more economic projects may be available over time. However, the analysis assumes that, if the Proposal is approved by the Commission, Transpower would seek approval for additional projects such as the modelled projects to meet the GRS at an appropriate future date.

7.1.11 The Commission has used the additional modelled projects proposed by Transpower in modelling the Proposal, but has, after discussing the issues with Transpower, adjusted two modelled projects associated with the 220kV Alternative. Specifically:

- (a) The Commission adjusted the cabling costs of the modelled project comprising a second set of cables from Ormiston Road to Otahuhu in

⁷² Proposal, Attachment D.

2024. This change is discussed further in paragraphs 7.3.10 to 7.3.15 below; and

- (b) The Commission assumed a 5 year lead time for the modelled project comprising the construction of a second 220kV line by 2031, but allowed an additional year for Transpower to obtain related easements.⁷³ This change is discussed further in paragraphs 7.3.16 to 7.3.18 below.

7.1.12 The modelled projects as proposed by Transpower and as adjusted by the Commission are called the **Modelled Projects**.

Does the Proposal reflect GEIP?

7.1.13 Although it has not been used before in New Zealand, the use of 400kV and higher transmission voltages is widespread in the developed and the developing world.

7.1.14 The Commission expects that Transpower would be capable of ensuring delivery of a 400kV capable transmission line, configured to operate initially at 220kV, in accordance with GEIP as set out in paragraph 5.2.12 above.

Conclusion on whether the Proposal meets the requirements of rule 13.4.1.1

7.1.15 On the basis of the information available to it, the Commission is satisfied that the Proposal reflects GEIP in meeting the GRS.

7.2 Test 2 - Does the Proposal comply with the processes set out in the rules? (rule 13.4.1.2)

Submission of the GUP and provision of content

7.2.1 On 23 May 2005, the Commission requested that Transpower prepare and submit a GUP within three months. Following a number of discussions with Transpower from May 2005 regarding the content of the 2005 GUP, in August 2005 the Commission extended the deadline for submitting the GUP from 24 August 2005 to 30 September 2005.

7.2.2 On 30 September 2005, Transpower submitted:

- (a) a comprehensive plan for asset management and operation of the grid (volume 1 of the 2005 GUP);
- (b) a list of investment contracts (volume 1 of the 2005 GUP);
- (c) the Original Proposal (volume 2 of the 2005 GUP); and
- (d) a proposed upgrade of the HVDC link between Benmore and Haywards (volume 3 of the 2005 GUP).

⁷³ Transpower assumed a 5 year lead time along with one extra year for project delivery risk.

- 7.2.3 On 31 October 2005, Transpower submitted two further economic investment proposals as volume 4 of the 2005 GUP.
- 7.2.4 As set out in section 4 of this document, the Proposal forms part of the 2005 GUP. The Proposal replaces the Original Proposal, and accordingly substantially amends volume 2 of the 2005 GUP. The Proposal also consequentially amends the executive summary in volume 1 of the 2005 GUP.⁷⁴
- 7.2.5 Finally, on 11 December 2006, Transpower submitted another economic reliability investment as volume 5 of the 2005 GUP. That investment comprises a new GIS facility adjacent to, but physically separate from, the existing outdoor 220kV switchyard at Otahuhu.
- 7.2.6 The Commission is satisfied that the 2005 GUP meets the requirements of rule 12.3.

Complying with the timetable

- 7.2.7 In accordance with rule 13.2, the Commission wrote to Transpower on 13 October 2006, setting out a proposed timetable and process for consultation on the Proposal.
- 7.2.8 In a letter dated 20 October 2006, Transpower advised that it did not have any objection to the proposed timetable and process. Accordingly, the timetable was agreed under rule 13.2.1.
- 7.2.9 The agreed timetable anticipated that the Commission would use its best endeavours to make a decision on the Proposal on or by 19 December 2006. However, despite using its best endeavours, having regard to the amount of information the Commission was required to consider and the importance of the issues, the Commission determined that it would not be able to make a decision by that date.
- 7.2.10 Accordingly, on 14 December 2006, the Deputy Chair of the Commission raised with Transpower the need to amend the agreed timetable to allow more time for the Commission to properly consider the Proposal. The Commission and Transpower agreed to amend the timetable to change the date for a decision to 31 January 2007.
- 7.2.11 The Commission is satisfied that Transpower has complied with the timetable (as extended) to date.

Requests for information and further investigation

- 7.2.12 Since the Proposal was submitted on 20 October 2006, the Commission has made a number of requests for further information in relation to the Proposal,

⁷⁴ Appendix B of the Proposal sets out how the Proposal amends the 2005 GUP.

including the modelling and economic analysis on which the expected net market cost of the Proposal has been based.

7.2.13 The Commission did not request Transpower to evaluate any further alternative projects, but did request Transpower to provide additional information regarding the three transmission options evaluated by Transpower in the Proposal.

7.2.14 In the Commission's view, Transpower has endeavoured to respond comprehensively to the Commission's requests for further information. The Commission also records that Transpower responded to the Commission's requests within very short timeframes, which has assisted the Commission to progress its deliberations quickly.

Conclusion on whether the Proposal meets the requirements of rule 13.4.1.2

7.2.15 The Commission is satisfied that Transpower has met (and therefore the Proposal meets) the requirements of rule 13.4.1.2.

7.3 Test 3 - Does the Proposal meet the requirements of the GIT? (rule 13.4.1.3)

7.3.1 This section summarises key aspects of the Commission's application of the GIT to the Proposal and the 220kV Alternative.⁷⁵

7.3.2 Applying the GIT involves quantifying, to the extent practicable, the costs and benefits associated with the Proposal and the 220kV Alternative. The following sets out the Commission's conclusions in respect of these costs and benefits.

Costs

7.3.3 Clause 23 defines "costs" as "the present value of the costs of a **proposed investment or alternative project** to those persons who produce, distribute, retail and consume electricity in New Zealand over a period of 20 years from the commissioning date..." including:

*"(a) capital costs incurred prior to the commissioning of the **proposed investment or alternative project** (as the case may be), including interest during construction" (clause 23.1 – **capital costs**);*

*"(b) operating, maintenance and dismantling costs over the operating life of the **proposed investment or alternative project** (as the case may be)" (clause 23.2 – **O&M costs**);*

*"(c) costs to **participants** associated with testing of the **proposed investment or alternative project** (as the case may be)" (clause 23.3 – **testing costs**);*

⁷⁵ As set out in section 6.9, the 220kV Alternative is the only alternative against which the Commission has undertaken a full comparison for the purposes of satisfying itself of the matters specified in clause 4.1.1.

“(d) any additional amount, approved by the **Board**, that could reasonably be considered to be a cost related to the commissioning of a **proposed investment or alternative project** (as the case may be)” (clause 23.4 – **commissioning costs**); and

“(e) costs of complying with or arising pursuant to all applicable existing and anticipated laws, regulations and administrative determinations” (clause 23.5 – **statutory compliance costs**).

Capital costs

7.3.4 Capital costs data has a significant impact on NPV ranking because the capital costs occur in the early years of both the Proposal and the 220kV Alternative.

7.3.5 In order to assess transmission investment capital costs, the Commission is required to take a view as to the accuracy of Transpower’s cost estimates in relation to the Proposal and the 220kV Alternative.

Exchange rate conversions

7.3.6 A number of comments received during the Comments Period noted a discrepancy in the capital costs estimates used by Transpower for apparently identical items in the Proposal compared with the alternative projects considered by Transpower. An initial comparison by the Commission showed small but consistent discrepancies in favour of the Proposal.

7.3.7 The Commission requested Transpower to clarify its capital costs data. Transpower stated that it originally estimated capital costs using an exchange rate averaged over ten years. However, following a request from the Commission to modify its exchange rate methodology, Transpower used a one-month mean exchange rate, and calculated a “conversion factor” for each alternative and the Proposal.

7.3.8 The conversion factor is a simple scaling of the capital costs, based on the total “overseas component” of the relevant project, to convert a ten-year exchange rate to a one-month exchange rate.

7.3.9 The Commission considers that the scale factor is a reasonable approximation to re-costing all items, and gives the correct result when applied to all items. However, a side effect of the approximation is that there are small discrepancies if a subset of components are extracted and compared between the Proposal and the 220kV Alternative, because the scale factors are different. However, the Commission is satisfied that when all the capital expenditure items that are part of the Proposal and the 220kV Alternative are embedded within the NPV script, the discrepancy is trivial.

Adjustments to cabling costs

- 7.3.10 The Proposal includes a modelled project comprising a second set of cables being constructed from Ormiston Road to the Otahuhu substation in 2023. The 220kV Alternative also includes a modelled project that comprises a second set of cables from Ormiston Road to Otahuhu, but in 2024. Transpower's original treatment of the second set of cables in the Proposal differed (in a way that was favourable to the Proposal) from its treatment of the second set of cables in the 220kV Alternative.
- 7.3.11 The Commission's modelling team carried out revised modelling to ensure that the treatment of the second set of cables in both the Proposal and the 220kV Alternative were the same. The Commission's remodelling resulted in a \$0.9 million advantage (in NPV terms) to the 220kV Alternative.
- 7.3.12 In information provided on 17 January 2007, Transpower agreed that the treatment of the second set of cables in both the Proposal and the 220kV Alternative should be the same, and also carried out revised modelling of cable costs accordingly. Transpower's remodelling resulted in an \$8.8 million advantage (in NPV terms) to the 220kV Alternative. However, Transpower stated that the results of the remodelling were highly sensitive to assumptions regarding the location of proposed new substations in South Auckland.
- 7.3.13 Transpower and the Commission have been unable (in the time available) to resolve why their respective remodelling led to different results.
- 7.3.14 However, given the sensitivities of cabling costs to the location of the proposed new substation in South Auckland, the Commission has relied on the lesser difference, being \$0.9 million difference in NPV terms, for the purposes of analysing the Proposal and the 220kV Alternative.
- 7.3.15 Accordingly, the Commission has adjusted cabling costs in the relevant modelled project associated with the 220kV Alternative.

5 or 6 year lead time

- 7.3.16 In modelling the 220kV Alternative, Transpower has assumed that it is necessary to allow 5 years for each aspect of the construction of a second 220kV line (a modelled project) and then one extra year to allow for project risk.
- 7.3.17 While the Commission accepts that it is prudent to allow for a number of years for the construction of a second 220kV line, the Commission considers that a five-year lead time is appropriate and allows for delivery risk in respect of each capital cost item, other than securing easements for the line.
- 7.3.18 Accordingly, the Commission has assumed a five-year lead time for the construction of the second 220kV line by 2031, but has brought forward the date for obtaining easements by one year. This results in increasing the present value of easement costs associated with the 220kV Alternative by 7%.

PBA analysis

- 7.3.19 The Commission engaged Parson Brinckerhoff Associates (**PBA**) to assess the capital costs for each item of transmission equipment identified by Transpower for each of the Proposal and the alternative projects. The results of the PBA analysis are set in the PBA costs report.
- 7.3.20 The PBA capital costs estimates and Transpower's estimates are largely consistent. In light of this, Commission staff have relied on the capital cost estimates provided by Transpower, but have included the PBA cost estimates in the sensitivity analysis discussed later in this section.

O&M costs (clause 23.2)

- 7.3.21 Different transmission investments may lead to different operation and maintenance (**O&M**) costs.
- 7.3.22 Transpower has supplied the Commission with what it considers are reasonable O&M costs for the Proposal and the 220kV Alternative. These costs have been included by the Commission in the GIT analysis.

Testing costs (clause 23.3) and commissioning costs (clause 23.4)

- 7.3.23 Clauses 23.3 and 23.4 include the costs associated with testing and commissioning of a proposed investment or alternative project in the definition of "costs".
- 7.3.24 Transpower has included the cost associated with testing and commissioning the Proposal as part of the capital cost estimates discussed above.
- 7.3.25 The Commission considers that costs associated with testing and commissioning of the Proposal and the 220kV Alternative will not be significantly different.

Statutory compliance costs (clause 23.5)

- 7.3.26 Clause 23.5 refers to costs associated with complying with existing or anticipated legislation.
- 7.3.27 In the Proposal Transpower states that two statutory compliance costs have been separately identified, costed and included in the GIT analysis, being:
- (a) consenting costs, which are the costs of satisfying the requirements of the Resource Management Act 1991, the Electricity Act 1992, the Public Works Act 1981 and other relevant legislation; and
 - (b) a carbon tax of \$15 per tonne of CO₂ in 2006 dollars.⁷⁶

⁷⁶ Transpower Economic Report, paragraph 3.6.2, page 35.

7.3.28 The Commission has also included the cost noted in (a) as part of the capital cost estimates for the Proposal and the 220kV Alternative, and included the carbon tax in (b) when applying the GIT to the Proposal and the 220kV Alternative.

Market benefits

7.3.29 Clause 27 defines “market benefits” as “the present value of the benefits to those persons who produce, distribute, retail and consume electricity in New Zealand from a **proposed investment** or **alternative project** over a period of 20 years from the commissioning date...”⁷⁷ including:

- “(a) *changes in fuel cost of **existing assets, committed projects and modelled projects***” (clause 27.1 – fuel cost benefits);
- “(b) *changes in the value of involuntary **demand curtailment***” (clause 27.2 – reliability benefits);
- “(c) *changes in the costs of **demand-side management***” (clause 27.3 – demand-side management cost change benefits);
- “(d) *changes in costs resulting from the deferral of capital expenditure on **modelled projects***” (clause 27.4 – deferral benefits);
- “(e) *changes in costs resulting from differences in the amount of capital expenditure on **modelled projects***” (clause 27.5 – capital cost benefits);
- “(f) *changes in costs resulting from differences in operations and maintenance expenditure on **existing assets, committed projects and modelled projects***” (clause 27.6 – O&M benefits);
- “(g) *changes in costs for ancillary services*” (clause 27.7 – ancillary services benefits);
- “(h) *changes in losses, including local losses*” (clause 27.8 – loss benefits);
- “(i) *subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations*” (clause 27.9 – statutory compliance benefits);
- “(j) *the value of any material real options associated with the **proposed investment** or **alternative project***” (clause 27.10 – real options benefits); and
- “(k) *subject to clause 10, **competition benefits***” (clause 27.11 – competition benefits).

⁷⁷ If significant market benefits or costs are expected to arise from the proposed investment or alternative project after that time, a terminal benefit calculation may be carried out to quantify these benefits or costs.

Fuel cost benefits (clause 27.1)

- 7.3.30 Fuel cost benefits arise when a proposed transmission investment enables generation plant(s) with lower fuel costs to be dispatched, i.e. the proposed investment reduces possible out-of-merit-order dispatch.
- 7.3.31 The Commission considered the following possible fuel cost benefits:
- (a) water is used that would have been spilled;⁷⁸
 - (b) lower cost thermal is dispatched (eg Huntly is dispatched ahead of New Plymouth); and
 - (c) lower cost geothermal/wind is dispatched instead of thermal and/or hydro.
- 7.3.32 The fuel cost benefits of relieving constraints are not considered material to the Commission's decision for the following reasons:
- (a) The amount of water that may be spilled in the case where a constraint reduces northwards flow into the Auckland region is likely to be small. During a constraint, the energy that would have been transferred in the absence of the constraint can generally be stored in the hydro lakes; and
 - (b) The occurrence of out-of-merit-order dispatch of stations located south of the constraint (being relieved) is not altered by the Proposal or the 220kV Alternative and related modelled projects, as they both result in very similar levels of point-to-point transmission capacity.
- 7.3.33 Accordingly, the Commission considers that the fuel cost benefit differences between the Proposal and the 220kV Alternative, if any, are likely to be negligible and, therefore, they are not included in applying the GIT to the Proposal.

Reliability benefits (clause 27.2)

- 7.3.34 Reliability benefits occur when there are differences in expected unserved energy between a proposed investment and an alternative project. The reliability benefits can also be used to ascertain whether supply security levels greater than *N-1* into the Auckland region are economic.
- 7.3.35 As a first step, the Commission investigated the trade-off between reliability benefits and project timing, and determined that the reliability benefits obtained from the Proposal supported a need date of 2015, and also supported an *N-G-1* reliability standard in this case.⁷⁹

⁷⁸ Hydro spill may occur for a number of reasons. An example of this would be spill required to ensure storage levels are not breached should inflow exceed generation capability. Additionally, spill may occur due to coincident inflow issues and transmission constraints.

⁷⁹ The Commission's approach to the *N-G-1* reliability standard is discussed in section 5.2 above.

- 7.3.36 In comparing the Proposal and the 220kV Alternative over the 20-year analysis period, the Commission concluded that the capacity provided by the Proposal and the 220kV Alternative appear to be very similar, and did not identify any difference in reliability benefits as between the Proposal and the 220kV Alternative until the later addition (after 2033) of relevant modelled projects associated with the Proposal and the 220kV Alternative respectively. The relevant modelled projects are, in the case of the Proposal, the conversion of the 400/220kV line to 400kV operation, and, in the case of the 220kV Alternative, the construction of a second 220kV line.
- 7.3.37 After the relevant modelled projects are added, the Commission's initial analysis suggested that the 220kV Alternative would have greater reliability benefits than the Proposal due to the possibility of a double circuit forced outage on the modelled 400kV line.
- 7.3.38 In response to the Commission's questions on this issue, Transpower initially suggested that the possibility of a double circuit forced outage on the modelled 400kV line was approximately 1 in 40 years,⁸⁰ but later suggested that the failure rate for such a line was more likely to be 1 in 137 years.
- 7.3.39 If a 1 in 40 year fault rate is assumed, this would mean that a reliability benefit would arise in favour of the 220kV Alternative compared with the Proposal. Alternatively, if a 1 in 137 year fault rate is assumed, any reliability benefit for the 220kV Alternative would be trivial.
- 7.3.40 The Commission notes that identifying and calculating reliability benefits attributable to the period arising after the 400/220kV line is converted to 400kV operation, and comparing the level of reliability that would exist during the same period if the 220kV Alternative went ahead and a second 220kV line was also constructed, requires assessments to be made very far into the future. In light of this, and the uncertainty as to the appropriate assumed outage rate, the Commission has determined that it will disregard these possible reliability benefits.
- 7.3.41 Finally, in information provided by Transpower on 17 January 2007, Transpower indicated that the Proposal may allow a higher level of grid reliability during the analysis period than previously advised. This is due to a change to the rating of the line during the analysis period. If it is the case that the Proposal would have greater reliability than the 220kV Alternative during the analysis period, this would have the effect of increasing the difference (in NPV terms) between the Proposal and the 220kV Alternative. That is, the Proposal would minimise expected net market costs by a greater amount.
- 7.3.42 While the Commission is currently evaluating the claimed greater reliability benefit attributable to the Proposal during the analysis period, the Commission

⁸⁰ In the Proposal, Supplementary Information, Transpower stated that the failure rate for a 400kV line would be 1 in 20 years. The Commission considered that this rate was overly conservative, and notified Transpower. Transpower agreed that that rate was an error, and should have been documented as 1 in 40 years.

has not included the claimed additional reliability benefit in favour of the Proposal for the purpose of its analysis or decision-making.

Demand-side management cost change benefits (clause 27.3)

7.3.43 Demand-side management cost change benefits were not included by the Commission in applying the GIT to the Proposal and the 220kV Alternative.

Deferral benefits (clause 27.4)

7.3.44 If a major grid investment is delayed by using other, less costly, means to ensure that the power system continues to meet the GRS, “deferral benefits” can result. These benefits are captured as capital cost benefits, discussed below.

Capital cost benefits (clause 27.5)

7.3.45 Capital cost differences exist between the Proposal and the 220kV Alternative (in conjunction with appropriate modelled projects). These are set out in Transpower’s costing report.⁸¹

O&M benefits (clause 27.6)

7.3.46 Differences between O&M benefits of the Proposal and the 220kV Alternative are not significant. The Commission has incorporated the O&M figures supplied by Transpower in the GIT analysis.

Ancillary services benefits (clause 27.7)

7.3.47 In applying the GIT, the Commission has assumed that ancillary services benefits will occur if any existing contracted voltage support is not required with a transmission investment project implemented.

7.3.48 In the past voltage support contracts have been managed by the System Operator and have generally been regarded as short-term fixes to longer-term issues that grid investment would ordinarily alleviate. However, the Commission considers that costs associated with voltage support contracts need to be traded off against transmission investment costs on an economic basis.

7.3.49 In many instances, voltage support may be regarded as a genuine alternative to transmission investment, an example of which would be the voltage support provided by the synchronous machines at Otahuhu and Marsden in the Auckland region.

7.3.50 The Commission does not consider that there will be any material difference in expected ancillary services benefits attributable to the Proposal and the 220kV Alternative, and accordingly has not included such benefits in the GIT analysis.

⁸¹ Proposal, Attachment F, Transpower Costing Report.

Competition benefits (clause 27.8)

- 7.3.51 Transpower initially claimed the existence of some competition benefits that the Commission considers (and Transpower now agrees) are better considered capacity benefits and perception benefits. These benefits are considered as non-quantifiable benefits under clause 9.
- 7.3.52 The Commission is not required to take into account competition benefits. Rather it may choose to do so, but only if the claimed benefit can be separately identified and calculated.
- 7.3.53 To date, two possible competition benefits as defined in clause 22 have been identified.
- 7.3.54 The first is avoiding a generator knowingly investing in sub-optimal plant located in Auckland. This may occur if the generator perceived a risk of delay of a second 220kV line in the alternative, therefore facilitating the exercise of market power within the Auckland region. This issue was identified by the Energy Centre in its comments on the Proposal provided in November 2006.⁸²
- 7.3.55 To the extent that the Proposal (compared with the 220kV Alternative) mitigates against the possible use of market power in this context may constitute a competition benefit in favour of the Proposal. However, Transpower has not separately identified or calculated this benefit. As noted by the Energy Centre, modelling competition benefits is highly complex and its own preliminary modelling results were not yet reliable enough to base major conclusions on.
- 7.3.56 The second possible competition benefit is the reduction in exercise of market power caused by the perception of increase future certainty of capacity, or the ability to quickly release that capacity.
- 7.3.57 The Commission has not taken either of the above benefits into account because they have not been calculated.

Loss benefits (clause 27.8)

- 7.3.58 In HVAC systems, higher voltages result in lower electric current flow for the same level of electrical energy transmission and so less loss of energy. The Commission conducted an analysis to determine the extent of losses from the Proposal and 220kV Alternative, and to compare the value of those losses. Any differences in losses relative to the Proposal are termed “loss benefits” (or “loss costs” if they are negative).
- 7.3.59 The Commission investigated the loss costs of the Proposal and the 220kV Alternative using a power flow modelling approach. The transmission network configurations derived by the SSG analysis for the Proposal and the 220kV Alternative were used to calculate losses for each modelled half-hour demand

⁸² The Energy Centre’s views are discussed further in paragraphs 6.8.6-6.8.9 above.

period, with loss costs calculated based on the system short run marginal cost (**SRMC**) with modelled generation on SRMC merit order dispatch. The results of the Commission's loss benefits analysis show a loss benefit in favour of the Proposal of \$4.4 million.

- 7.3.60 The results of the Commission's analysis of losses are incorporated in table 8.1 in section 8.

Statutory compliance benefits (clause 27.9)

- 7.3.61 The most likely statutory compliance benefit is that of reducing an emissions charge such as a carbon tax. The Commission agrees that a form of carbon tax is likely in New Zealand and that this would affect the electricity industry. Accordingly, the Commission has incorporated a carbon tax of \$15 per tonne of CO₂ in the modelling.

Real option benefits (clause 27.10)

- 7.3.62 The Commission has used the Monte Carlo/NPV model to calculate the real option value of flexible investment timing. Uncertainty associated with demand and the timing of generation development is sampled using Monte Carlo techniques to value the modified timing of the 220kV Alternative. The model is then used to calculate an average NPV for each benefit which recognises input uncertainties.
- 7.3.63 The optionality of a 400kV/capable line has been taken into account through the transformer rationalisation benefit discussed below, but neither the Commission nor Transpower has otherwise separately estimated this real option.

Terminal Benefits and Terminal Costs (clauses 23 and 27)

- 7.3.64 The calculation of Terminal Benefits and Terminal Costs is not an attempt to estimate a salvage or residual value for the asset as if 2033 were the end of the asset's life.⁸³ The Commission identified four elements to the Terminal Benefits and Terminal Costs in the GIT:
- (a) the potential excess transfer capacity (a benefit);
 - (b) the cost to release that capacity;
 - (c) the O&M costs associated with operating the line beyond 2033; and
 - (d) the change in the cost of transmission losses for the 220kV Alternative relative to the losses associated with the Proposal.

⁸³ Once the capacity has been exhausted, and provided it is suitably maintained, the asset can continue to be used (presumably at full capacity) to transfer electricity. As long as a price is charged for this transfer, therefore giving rise to a future revenue stream, the asset has some underlying value.

- 7.3.65 Both Transpower and the Commission approached the calculation of Terminal Benefits based on the potential $N-1$ thermal capacity of transmission into the Auckland region at the end of the 20 year analysis period for the Proposal and the 220kV Alternative, valued at the equivalent long run marginal cost (**LRMC**) of transmission on a per MW basis.
- 7.3.66 Since the various assets that make up the Proposal and the 220kV Alternative do not represent every possible investment that may be installed to access potential thermal capability, there may be a capital cost to release that additional capacity.
- 7.3.67 In its analysis, the Commission assumed that transmission losses and O&M costs would be constant for 20 years from 2033.
- 7.3.68 The Commission's Monte Carlo/NPV calculation lead to a small Terminal Benefit for the proposal of \$14.8 million, and \$7.1 million for the 220kV Alternative.
- 7.3.69 The Commission's conclusions on Terminal Benefits and Terminal Costs are included in table 8.1 in section 8.

“Strategic Benefit” – Transformer rationalisation benefit

- 7.3.70 In addition to the benefits listed in clause 27, the Commission has considered Transpower's proposed “strategic benefit”.
- 7.3.71 Specifically, in its NPV analysis of the Proposal, Transpower included an estimated \$4.5 million strategic benefit in favour of the Proposal. The strategic benefit relates to claimed savings that accrue if a second 400kV line is connected from Whakamaru through the North Island (**CNI 400kV line**) at a later point in time.
- 7.3.72 Transpower calculated this figure by assuming that it would re-use two of the 400kV interconnectors associated with the Proposal at the southern termination point of the transmission line to which the Proposal relates.
- 7.3.73 However, after discussions between the Commission and Transpower, the Commission removed the \$4.5 million strategic benefit attributable to the Proposal. This is because the \$4.5 million strategic benefit assumed that the construction of the CNI 400kV line is certain. The Commission does not consider that this is appropriate. However, the Commission agrees that it is appropriate to include the \$4.5 million figure in the Monte Carlo analysis, which means that the economic model produces a number that reflects varying probabilities that a CNI 400kV line will be built.
- 7.3.74 In addition, the Commission considered that the “strategic benefit” label did not accurately convey the nature of the benefit. Instead, in its NPV analysis, the Commission has referred to this benefit as a transformer rationalisation benefit.

- 7.3.75 The Commission requested Transpower to provide revised information regarding possible transformer rationalisation that would exist if the Proposal were approved. Transpower estimated that the benefit to the Proposal in the event the CNI 400kV line is constructed would be a cost saving of approximately \$37 million in 2033 dollars. Applying an NPV calculation results in \$3.6 million in NPV terms.
- 7.3.76 This differs from the Commission's modelling. The Commission's modelling results in an estimated \$30 million benefit to the Proposal in 2033. This translates into an NPV impact in favour of the Proposal of approximately \$3 million.
- 7.3.77 Either approach set out above impacts only in a very minor way on the NPV of the Proposal. The Commission has decided to include a \$3 million transformer rationalisation benefit in favour of the Proposal.

Non-quantifiable material market costs and benefits

- 7.3.78 Clause 9 of the GIT states:

*“where a **material benefit** or **cost** cannot be quantified, the direction of the **market benefit** or **cost** and likely magnitude of the **market benefit** or **cost** must be identified.”*

- 7.3.79 Transpower stated that the Application for Approval did not estimate the likely magnitude of material market benefits to the Proposal under clause 9 because *“their direction was in favour of the Proposal and, as the NPV of the Proposal was higher than that of the alternative, it was not necessary to identify the likely magnitude”*.⁸⁴
- 7.3.80 Since Transpower submitted the Proposal, Transpower and the Commission have discussed possible material market benefits and costs that may be included in applying the GIT to the Proposal.
- 7.3.81 As a result of that further discussion, the Commission has considered for the following possible material market benefits:
- (a) business confidence benefits;
 - (b) capacity benefits arising from dynamic efficiency benefits of the Proposal for new generation investment;
 - (c) benefits arising from facilitating renewables;
 - (d) regional environmental and social benefits, which are benefits attributable to the Proposal arising from mitigation of risk that land access will be more difficult in the future; and

⁸⁴ Document provided by Transpower on 17 January 2007 entitled “Further information in response to Electricity Commission's questions”, section 1.5, paragraph 14, page 6.

(e) a renewables benefit relating to loss benefits attributable to the Proposal.

7.3.82 The Commission considers that business confidence, capacity benefits, and facilitating renewables are all different facets of the perception of the relative uncertainty of a second 220kV line being commissioned on time, and accordingly has grouped them broadly under the heading “perception benefits”.

Perception benefits

Business confidence

7.3.83 Transpower has sought to estimate business confidence benefits by estimating foreign direct investment effects. In particular, Transpower has relied on the report by Castalia which was included as Attachment N of the Proposal.

7.3.84 The Commission engaged Professor Tim Hazledine, a New Zealand expert on foreign direct investment, to review the Castalia report.

7.3.85 Castalia used increases in inward foreign direct investment as a proxy for business confidence. Castalia’s key contention is that “*manifestly strong infrastructure*” will increase inward foreign direct investment, which will in turn result in significant GDP and welfare gains. Specifically, Castalia suggests that an increase of about \$2.3 billion in the annual flow of foreign direct investments for five years would generate an additional \$100 million present value of economic welfare.

7.3.86 On the other hand, Professor Hazledine considered that Castalia’s claimed link between infrastructure and inward foreign direct investment may be tenuous, and concluded that he was not confident in the validity of the assumptions and procedures used by Castalia.

7.3.87 In the information provided by Transpower on 17 January, Transpower provided a revised analysis of business confidence benefits, and suggested a lower bound of \$66 million, and an upper bound of significantly higher than \$66 million.

7.3.88 In principle, the Commission agrees that business confidence is likely to constitute a material market benefit. The Commission also accepts that, if the Proposal would result in a net increase in business confidence, then the direction of that benefit is likely to be in favour of the Proposal.

7.3.89 However, in determining a likely magnitude, the Commission considers that it must take into account the probability of the claimed business confidence benefits accruing. The information available to the Commission does not justify the Commission having sufficient certainty of the likely magnitude of the claimed business confidence benefits at this stage.

Capacity benefits

- 7.3.90 Transpower has suggested that the Proposal gives rise to two capacity benefits.⁸⁵
- 7.3.91 First, Transpower suggest that uncertainty and future returns for generators (arising from the “implementation risk”) will cause the cost of capital for generators to increase.
- 7.3.92 In the Commission’s view, the perceived implementation risk may be considered by generators to be too small to affect prices meaningfully. The perceived risk must be weighted against perceived materiality or likelihood of the risk.
- 7.3.93 The Commission considers that, given the other uncertainties faced by generators (for example, uncertain future returns due to hydro inflow uncertainty, the actions of other generators, demand growth, the actions of major electricity users, and regulatory uncertainty), the suggested higher cost of capital should be disregarded as speculative and immaterial.
- 7.3.94 The second type of capacity benefit suggested by Transpower is a bias in spot prices which favours generation investment in Auckland, even though such investment would be more expensive than if the investment had been made elsewhere. Transpower assumes that the bias in spot prices favouring Auckland is a consequence of the implementation risk described above.
- 7.3.95 The Commission considers that the scenario Transpower describes is unlikely to eventuate and therefore the Commission does not consider that the suggested capacity benefit relating to the claimed bias in spot prices favouring Auckland is a material market benefit. Accordingly, the Commission has not included this benefit in applying the GIT to the Proposal.

Facilitating renewables

- 7.3.96 Transpower states that the Proposal will facilitate the development of renewable generation. One of the reasons the Proposal is considered by Transpower to facilitate renewables is the perception of implementation risks associated with the second 220kV line (a Modelled Project associated with the 220kV Alternative) causing more generation to be built in the upper North Island. This is a different facet of the capacity benefit described above.
- 7.3.97 Transpower considers that the 220kV Alternative would lead to additional thermal plant being commissioned in the upper North Island as a result of this perception of implementation risk. The cost of carbon dioxide emissions from that plant over its lifetime has then been estimated to give a present day NPV total of up to \$78 million.

⁸⁵ Transpower initially labelled these benefits as competition benefits, but the Commission did not consider that these benefits are competition benefits as defined in the Rules.

7.3.98 The Commission does not consider that the claimed benefit is credible. In particular, the Commission considers that:

- (a) a generator making a decision to invest in sub-optimal plant runs the risk of being stranded with that plant if the second 220kV line proceeds as anticipated;
- (b) although aware of the implementation risk associated with building a second line, it is unlikely that a generator would judge it to be sufficiently material or likely to affect its decision; and
- (c) some thermal plant is probably required in any event, even in a predominantly renewables future, so that, at most, the cost will be a change in location and no change in emission, or a bringing forward of a thermal plant required, with minimal emissions to meet peak demand during the period the 220kV line is delayed.

7.3.99 For these reasons, the Commission does not consider that any material market benefit arises in favour of the Proposal.

Environmental and social benefits associated with land access issues

7.3.100 Transpower's claimed environmental benefit of \$69 million is associated with the increased costs of future land access. The claimed environmental benefit has three components:

- (a) property values could double;
- (b) urban sprawl of another 10 kilometres; and
- (c) an increase in line length required of 50%.

7.3.101 The Commission considers that each component should be weighted by the probability that the component will occur. Further, the Commission considers that these issues are properly considered within a sensitivity analysis associated with the NPV calculations, and do not separately comprise a material, non-quantifiable benefit.

7.3.102 Accordingly, the claimed environmental benefit has not been separately included in the application of the GIT to the Proposal, as the component benefits are already incorporated in other parts of the analysis.

Renewables benefit

7.3.103 Transpower raised another possible non-quantifiable benefit on 15 December 2006. That benefit is a renewables benefit relating to possible loss benefits for the Proposal that has been underestimated because actual line flows would be more volatile than modelled because of the development of intermittent renewables.

7.3.104 Because the Commission has chosen to adopt a predominantly renewables MDS, the Commission considers that any loss benefit of the nature described above will be captured in the Commission's Monte Carlo/NPV model. Accordingly, the Commission has not separately included a renewables benefit in the application of the GIT to the Proposal.

Sensitivity Analysis

7.3.105 Clause 16 requires a sensitive analysis to be applied in assessing the expected net market benefit and costs. Clause 17 lists a number of specific sensitivities that must be applied to test the robustness of results to changes in the underlying model assumptions, unless to do so is either not reasonably practicable or not reasonably necessary.

7.3.106 The sensitivities applied by the Commission are set out in table 7.1.

Table 7.1: Sensitivity analysis parameters used by the Commission

Variables & clause in Schedule F4	Sensitivity
<i>17.1 - forecast demand</i>	
Varying Demand Growth	Embodied in the Monte Carlo analysis
Draft 2007 SOO demand forecasts	Assumes demand forecasts developed for the Draft 2007 SOO
<i>17.2 - the size, timing, location and operating and maintenance costs of the proposed investment or alternative project; and existing assets, committed projects and modelled projects</i>	
Change in costs of committed/modelled projects, proposed investment and alternative projects (also relevant to 17.3)	Capital cost +20%, -5%
Change in costs of Proposal	Allow for easement costs to be bought forward
Change in timing of 220kV Alternative	Investigated advancing series capacitor timing
<i>17.3 - the capital cost of the proposed investment or alternative project</i>	
Change in costs of Proposal/220kV Alternative	Apply an inflation of 0% per annum and 6% per annum for easement costs Increase cost of easements due to urban sprawl

2011 dollars	Inflating nominal costs to anticipated year of commissioning
Exchange rate sensitivities	10 year average rate
17.6 and 17.7 - the discount rate used	Between 4% and 10%
17.8 - a range of consistent hydrological inflow sequences as defined in the SOO and centralised data set	Applied hydro inflow sequences sourced from SOO and centralised data set
Additional sensitivities	
Cost of losses	Use SRMC of generation
Auckland generation assumptions	Assumes new generation in Auckland commissioned by 2030 at the latest

7.3.107 The Commission has not carried out a sensitivity analysis with the variables in table 7.2 for the reasons set out in the table.

Table 7.2: Sensitivity analysis variables not applied by the Commission

Variable & clause in Schedule F4	Comment
17.2 - the size, timing, location and operating and maintenance costs of the proposed investment or alternative project; and existing assets, committed projects and modelled projects	
Reasonable variations in size, location and maintenance costs.	Not reasonably necessary
Timing of existing assets	Not reasonably practicable
Delay of Proposal/220kV Alternative	Not reasonably necessary, as modelled in reference case
Operating costs of existing assets	Not reasonably necessary – does not distinguish between the Proposal and 220kV Alternative
Delay of modelled projects	Not reasonably necessary – does not distinguish between the Proposal and 220kV Alternative

17.4 - the timing of decommissioning, removing or de-rating decommissioned assets	Not reasonably necessary – does not distinguish between the Proposal and 220kV Alternative
17.5 - the value of unserved energy	Not applicable due to the modelling approach used
17.9 - generator and demand-side bidding strategies	Optimisation modelling was used rather than market modelling (focus on calculating economic benefits and costs)
17.10 - key input variables in the calculation of competition benefits	Not reasonably necessary – does not distinguish between the Proposal and 220kV Alternative
17.11 - carbon charge	Not reasonably necessary – generation cost input variation dealt with through SRMC sensitivity
17.12 - the probability of occurrence of an MDS	Not reasonably necessary or practicable because Commission chose to adopt one MDS, therefore no ability to change weighting

8 GIT RESULTS

8.1 NPV Analysis

- 8.1.1 A full NPV results summary of the Commission's GIT analysis is presented below.
- 8.1.2 The NPV results include the capital cost items and market benefits and costs identified and analysed by the Commission. These results also incorporate the Monte Carlo analysis which has been used to ascertain option value benefits based on future uncertainties.
- 8.1.3 The results are presented in terms of the NPV of the 220kV Alternative (reference case) less the NPV of the Proposal.

Table 8.1: Central NPV results by cost and benefit category

Element	220kV Alternative \$million	Proposal \$million	NPV difference \$million
Capital costs	684.2	683.9	-0.3
Operating and maintenance costs	23.4	24.7	1.3
Net transmission losses	0	4.4	4.4
Terminal value benefits	7.2	14.8	7.6
Total	700.4	689.5	11.0

8.2 Sensitivity analysis

- 8.2.1 Table 8.2 provides the sensitivity analysis results. For a full explanation of these sensitivity results, refer to the Commission Economic Report.

Table 8.2: Sensitivity results

Element	220kV Alternative \$million	Proposal \$million	NPV difference \$million
Central result	700	689	11
2011 dollars	1116	1098	18
Capital cost + 20%	837	826	11
Capital cost – 5%	666	655	11
Loss costs at system SRMC	700	689	11
4% discount rate	947	881	66
10% discount rate	545	555	-10
Property cost escalation at 0% p.a.	684	682	2
Property cost escalation at 6% p.a.	728	699	29

Upper 50% of demand runs	743	717	26
Lower 50% of demand runs	660	663	-3
Exchange rate – 10 year average	693	688	5
Urban sprawl 10km	704	689	15
No new Akld generation after 2030	688	681	7
Easement costs at 2010	709	700	8
Electric vehicles recharging anytime	733	706	27
2007 SOO demand forecasts	622	639	-17

8.2.2 By a majority, the Commission considers that the NPV results in table 8.1 appear robust having regard to the results of the sensitivity analysis.

8.3 Conclusion on GIT results

8.3.1 By a majority, the Commission is reasonably satisfied that the Proposal:

- (a) minimises expected net market cost compared with possible alternative projects; and
- (b) the conclusion in (a) above is sufficiently robust having regard to the results of the sensitivity analysis.

8.3.2 Therefore, by a majority the Commission is reasonably satisfied that the Proposal satisfies the GIT.

9 DECISION

9.1 Summary of decision

- 9.1.1 The Commission emphasises that it is aware of the importance of an adequate and secure power supply to Auckland. In line with that, to date, and in parallel with the Proposal, Transpower has proposed, and the Commission has approved, a number of transmission upgrades that will enhance security of supply to Auckland in the short to medium term.
- 9.1.2 The Commission's analysis concludes that, unless there is a reduction in the growth in demand or assurance of new generation near Auckland, substantial transmission upgrades will be required.
- 9.1.3 Rule 13.4 provides that, in order to be able to approve a reliability investment, the Commission must be satisfied that the proposed investment:
- (a) reflects GEIP in meeting GRS (rule 13.4.1.1);
 - (b) complies with the processes set out in these rules (rule 13.4.1.2); and
 - (c) meets the requirements of the GIT (rule 13.4.1.3).
- 9.1.4 On the basis of the information provided to date, the Commission considers that the Proposal reflects GEIP in meeting the GRS and therefore meets the requirements of rule 13.4.1.1.
- 9.1.5 The Commission is satisfied that Transpower has complied with the relevant processes and therefore the Proposal meets the requirements of rule 13.4.1.2.
- 9.1.6 On the basis of the information provided to date, the view of the majority is that the Proposal minimises expected net market cost compared with the 220kV Alternative.
- 9.1.7 The view of the majority is that this conclusion is robust having regard to the sensitivity analysis carried out. Accordingly, the view of the majority is that the Proposal meets the requirements of the GIT.
- 9.1.8 This means that, under rule 13.4, the Board has the discretion to approve the Proposal. By a majority, the decision of the Commission is to approve the Proposal.

9.2 Other recommendations

- 9.2.1 As part of its decision, the Commission wishes to put forward three recommendations for Transpower's consideration. They are:
- (a) The Commission expects that Transpower will use efficient project management techniques to manage project costs and risks and, on an ongoing basis, will review the need date for the Proposal in light of

changing circumstances, keeping in mind the need to avoid unnecessary early expenditure while ensuring that the relevant assets are commissioned before they are needed. As part of efficient project management, the Commission also expects that Transpower will demonstrate the need to incur costs before committing to costs, and will publish regular reports that set out the progress of implementing the Proposal against both expected costs and costs with contingencies, and the reason(s) for any divergence.

- (b) The Commission expects Transpower to use reasonable endeavours to obtain consent under the Resource Management Act 1991 for the Pakuranga substation to be equipped with AIS rather than GIS. The Commission notes that it is not clear that GIS will be required at Pakuranga, and although the Commission's approval will cover the construction and commissioning of a GIS switchyard, the Commission views this as effectively a contingency. The Commission expects Transpower to diligently seek to minimise project costs and, if the construction of an AIS switchyard results in lower overall costs, the Commission expects Transpower to actively seek this outcome.
- (c) The Commission expects that Transpower will provide to the Commission as soon as possible an asset capability statement regarding the intended rating of the assets to which the Proposal relates, their electrical characteristics, and the reliability and availability expected for the assets. The asset capability statement must be consistent with performance assumed in applying the GIT, for example, the asset capability statement should include the expected single circuit and double circuit forced outage rates, with an expected repair time. The asset capability statement must also be consistent with the proposed interconnection rules.

10 MINORITY VIEW OF COMMISSIONER PINNELL

10.1 Overview

- 10.1.1 I support the majority decision of the Commission as laid out earlier in this document on all regulatory tests except one. While I am of the opinion that a substantial upgrade of transmission is required into Auckland, and that the options put forward by Transpower are all capable of providing secure supply, I am of the opinion that the Proposal fails the GIT and that there is at least one option having better value.
- 10.1.2 I have therefore dissented from the decision of the majority of the Commission to give notice of its intention to approve the Proposal.
- 10.1.3 If the Proposal is energised at 400kV, it almost trebles the transfer capacity from Whakamaru to Auckland compared with that currently provided by the six 220kV circuits. The Proposal, when energised at 400kV, is capable of meeting the needs of Auckland and Northland until late into the century.
- 10.1.4 However, even the 220kV Alternative has a much larger capacity than any other existing transmission line in New Zealand, and is of about the same capacity as the 400kV transmission line to which the Original Proposal related. The 220kV Alternative is capable of meeting needs in Auckland and Northland until about the middle of the century. Only if load growth turns out to be substantially greater than expected or if no new local generation is built in the Upper North Island (UNI) would there be a need for additional capacity within the next 30 years. On the other hand, low demand growth, improved efficiency of electricity use, load shifting from peak periods, or local generation have the potential to delay the need for additional transmission capacity until the end of the century.
- 10.1.5 The Proposal operating at 220kV and the 220kV Alternative are very similar in their electrical performance. The main difference is that the Proposal requires larger towers, in terms of height, base width and steel size. The Commission's advice⁸⁶ is that the average height of the proposed towers would be 60m, being 15m higher than the 220kV Alternative. This is a major factor in the Proposal having a 21% higher capital cost than the 220kV Alternative.
- 10.1.6 Up to the point of full capacity utilisation at 220kV (around 2050), there is therefore a reasonably certain advantage of \$47 million in NPV terms in favour of the 220kV Alternative arising from the capital, operation and maintenance cost differences.
- 10.1.7 When that capacity is exhausted, the same range of new investments would be available to each option, including 220kV, 400kV and HVDC, each having a range of technologies that may not be available today. The exception is that the Proposal is able to be upgraded to 400kV with the installation of transformers at

⁸⁶ PBA design report.

the South Auckland and Whakamaru substations. However, when the 400kV line is heavily loaded and serving a large portion of the Upper North Island load, the risk and consequences of double circuit failure become significant. Furthermore, it appears to be just as economic to build a second 400kV-capable line as to energise the Proposal at 400kV. I am therefore of the opinion that energising the Proposal at 400kV is not reasonably likely before a second 400kV line is built. A second 400kV line operating at 220kV would provide sufficient capacity for about a century before one of these lines would need to be energised at 400kV.

- 10.1.8 Of course, projecting short-term forecasts so far ahead is meaningless, given that we have no clear view of the future. Equally, investing now in capacity that will not be used for a very long time, and maybe never, is very difficult to justify.
- 10.1.9 Having reached the view that energising the Proposal at 400kV is not a reasonably likely second-stage investment, then the Proposal and the 220kV Alternative have identical future development options. Therefore, the analysis can be truncated at the time the capacity of the Proposal is exhausted. Contentious matters such as the need for early procurement of a corridor for a second line, or the need for additional cabling to connect a second line through another substation in South Auckland become common to the Proposal and the 220kV Alternative.
- 10.1.10 During the Commission's assessment of the Proposal, Transpower has presented analysis on unquantifiable benefits of the Proposal in terms of competition, capacity and investor confidence. The Commission has taken advice on these issues. I am of the view that the benefits assessed are so speculative as to be immaterial.
- 10.1.11 The economic analysis then simplifies to testing whether the capital, operating and maintenance cost advantage of \$47 million to the 220kV Alternative is reversed by other costs and benefits that are unique to each option. Those adjustments are small, resulting in an overall NPV advantage to the 220kV Alternative of \$39 million to \$45 million in my estimation. I therefore conclude that the Proposal fails the GIT.
- 10.1.12 In order for the Commission to approve the Proposal, we must be reasonably satisfied that it is more economic than the identified alternatives. One other alternative involved upgrading the capacity of the Otahuhu-Whakamaru A and B lines by duplexing using conventional conductors and the other involved upgrading the same lines using high temperature conductors.
- 10.1.13 Duplexing existing lines intuitively makes economic sense, in that it maximises the capacity of the existing system. Transpower is adopting that practice in the South Island. However, Transpower has not investigated these options for Auckland to the same extent as the new-build options. The investigations undertaken by Commission advisors cast serious doubts on the costs put

forward by Transpower. My tentative view is that duplexing using conventional conductors is likely to be more economic than the Proposal.

10.1.14 The rest of the opinion provides elaboration on the following specific aspects of the assessment of the Proposal and alternatives under the GIT:

- (a) Broad economic comparison of options;
- (b) Confidence in cost differences;
- (c) Grappling with uncertainty;
- (d) Plausibility of generation scenarios;
- (e) Plausibility of demand scenarios;
- (f) Unquantifiable costs and benefits not material;
- (g) Questionable need for a second substation in South Auckland;
- (h) Extension of a 400kV grid unlikely;
- (i) Risk of double circuit failure in high capacity lines;
- (j) Duplexing of the A and B lines; and
- (k) Modelling refinement.

10.1.15 The opinion concludes with a summary of the impact of these considerations on NPVs.

10.2 Broad economic comparison of options

10.2.1 Broad economic comparisons of the key options provide useful insights and help to explain the complex NPV analysis. The comparisons are intended to be illustrative rather than determinative.

10.2.2 Table 10.1 below shows unit and annualised costs relating to the capital costs of each option. The annualised costs are closely aligned with NPV analysis, as they represent the annual cost to recover the investment over the time taken to fully use the capacity of the investment, applying a 7% discount rate. They are analogous to loan repayments.

10.2.3 The capital costs were taken from Transpower's application and include line and substation costs, together with the costs of series capacitors installed 6 years after the main assets. Allowances as described in the footnote to the table were added to 'Energise at 400kV' options to account for the cost of special protection schemes and the estimated unserved energy.

10.2.4 The capacity increment is the simple *N-1* capacity increment based on winter circuit ratings.

10.2.5 The capacity life is the time required to exhaust the capacity increment, assuming a steady UNI load growth net of generation of 55MW/yr, which is consistent with the assumptions developed for the Commission's Draft 2007 SOO.

Table 10.1: Broad economic comparison of selected options

	Capex (\$million)	Capacity Increment (MVA)	Capacity life (years)	Unit cost (\$k/MVA)	Annualised cost (\$million/yr)
Initial Investment					
Proposal	390.8	2245	41	174	29.2
220kV Alternative	330.4	1997	36	165	25.3
Second-stage investment					
Energise at 400kV (N-1)	398.0	1215	22	328	35.9
Energise at 400kV (N)	288.0	1215	22	237	26.0
Duplicate line at 400kV	387.0	2970	54	130	27.8
Duplicate line at 220kV	313.8	2474	45	127	23.1

Note: Capex includes lines and substations, also series caps introduced 6 years after main assets.

'Energise at 400kV (N-1)' includes \$170 million for EUE (40 year MTBF, 3 day repair)

'Energise at 400kV (N)' includes \$20+40 million for special protection systems and EUE (40 year MTBF, 2 day repair time)

10.2.6 The table indicates that the 220kV Alternative is a lower cost option than the Proposal, both in terms of the initial investment and second-stage investments. The economics of 400kV over 220kV is negated by transformer costs and the modest increase in transfer capacity. The second-stage options for the Proposal, of energising at 400kV and accepting N security following a double circuit failure, or duplicating the line, have equivalent annualised costs. The N-1 option for energising at 400kV appears to be significantly more expensive than line duplication.

10.3 Confidence in cost differences

10.3.1 While the capital cost estimates are quoted accurate only to $\pm 20\%$, it is important to appreciate that the Proposal and the 220kV Alternative significantly differ only in terms of scale of the overhead lines. They traverse the same route, so will face the same geotechnical challenges, wind loadings and environmental issues. Their need dates and construction materials are identical, so they will face the same foreign exchange and commodity price risks. They have very similar substation requirements, and identical underground cable and voltage support requirements.

10.3.2 All of the factors that cause variations in the cost of building the 400kV-capable line under the Proposal and the 220kV Alternative line are therefore common.

- 10.3.3 It is therefore reasonable to conclude that the uncertainty in the relative capital cost of the Proposal and the 220kV Alternative is small and much less than the dollar amounts implied by the quoted capital cost estimation accuracy.
- 10.3.4 Similarly:
- (a) the factors resulting in O&M costs are common and therefore the uncertainties in O&M cost differences are small; and
 - (b) the electrical properties of the Proposal operating at 220kV and the 220kV Alternative are almost identical, meaning that the differences in the cost of losses are also quite certain.
- 10.3.5 In summary, it is reasonable to assume that cost differences between the Proposal and the 220kV Alternative for capital costs, O&M costs and the cost of losses are reasonably certain. Only the modelled projects required for second-stage investments have considerable uncertainty.

10.4 Grappling with uncertainty

- 10.4.1 Second-stage investments required around the middle of the century are quite uncertain in terms of their timing because of the difficulties in predicting demand and new generation technology, more so than is embodied in the scenarios used in the analysis. Fundamental shifts in factors causing demand growth are likely, such as energy efficiency and population growth. Also, the cost of second-stage investments are uncertain because of new transmission technology.
- 10.4.2 Assessment of the unquantifiable costs and benefits (considered under clause 9 of the GIT) is even more uncertain.
- 10.4.3 When the GIT was developed, the Commission adopted a default discount rate of 7% in the context of a 20-year future for analysis. The second-stage investments for this upgrade plan are predicted to be needed about 40 years after the initial investment, and to provide sufficient capacity for almost a century. Clearly, a 7% discount rate for use in assessing these second-stage investments needs to be reviewed.
- 10.4.4 In undertaking such a review, I have considered the following information:
- (a) advice received by the Commission from Frontier Economics prior to finalising the GIT;
 - (b) Transpower's submission on the GIT;
 - (c) Castalia's report to Transpower (Attachment L of the Application for Approval); and
 - (d) The Treasury's 2005 "Cost Benefit Analysis Primer".

- 10.4.5 I am of the view that the choice of discount rate for the GIT should be based on the principle of allocative efficiency. That is, the discount rate should reflect the risk-adjusted preferences of those paying for transmission services in relation to other investment choices they may have.
- 10.4.6 An important and consistent theme coming through all of the above references is that the risk should be assessed in terms of the uncertainties of the cash flows to those who bear the risks. It is therefore the uncertainties regarding the timing and magnitude of costs and benefits used in the GIT that should be considered. The uncertainties in the cash flows faced by Transpower should not be used, as those cash flows face different risks in accordance with the regulatory and commercial environment in which Transpower operates.
- 10.4.7 In my view, the certainty regarding the timing and magnitude of costs and benefits beyond the initial 20 years require a much higher rate than 7%. As I have no firm basis on which to estimate the higher rate, a reasonable approach may be to bracket the discount rate for costs and benefits beyond 20 years between 7% and 12%, noting that The Treasury recommends a default rate of 10%.
- 10.4.8 My approach to the identified unquantifiable costs and benefits is discussed in section 10.7.

10.5 Plausibility of generation scenarios

- 10.5.1 Choosing the generation scenarios (within the requirement to choose MDS under the GIT) has been contentious because of uncertainties, and the sensitivity they have on the GIT results as modelled by Transpower and the Commission.
- 10.5.2 For the purpose of regulatory certainty, my initial inclination was to confirm the use of the Initial SOO scenarios supplemented by a reasonable assumption regarding their extension to the end of the mandatory 20 year analysis period. The most obvious assumption to me was to extend generation at the same rate, given the parameters of the debate. Transpower was unwilling to accept such an assumption during the Interim Work Phase, and in later stages as recorded in their responses to the Commission on 15 December 2006 and 17 January 2007.
- 10.5.3 I am of the view that SOO scenarios should only be modified by the Commission (under clause 6.1 of the GIT) for the purposes of the assessment of a GUP in very limited circumstances, and when they are, full recognition must be taken of the precedent they establish for future SOOs and GUPs.
- 10.5.4 The only modification that I believe is reasonable in respect of the current Proposal is to adopt the scenarios set out in the Draft 2007 SOO, on which the Commission has considered submissions and made decisions in November 2006.

- 10.5.5 The Commission Economic Report usefully identifies that the nub of the matter is how much of the North Island load growth is likely to be served by new firm generation locating in the Upper North Island.
- 10.5.6 In making this choice, I would like to emphasise 2 points:
- (a) MDS should be reasonably likely, rather than conservative with respect to transmission needs. That is what the rules require and is also what is required for unbiased economic analysis. This contrasts with the conservative approach required to ensure reliability; and
 - (b) the concept of least cost expansion should be used for economic analysis, where generation and transmission are co-optimised. Transmission prices should not be substituted for transmission costs. New generation south of Whakamaru should only be included in preference to Upper North Island generation if it is of lower cost after including a share of the cost of the proposed transmission investment. Also, new generation behind other grid constraints, such as potentially in Taranaki should include transmission investment costs out of Taranaki, just as the cost of any necessary pipeline upgrades should be included in large-scale expansion of gas generation in Auckland. I accept that transmission pricing for the interconnected grid does not provide an efficient locational signal under the current regime, but note that the Commission intends to further investigate locational pricing.
- 10.5.7 The Commission's advisors have used least cost expansion principles in developing the detailed Generation Expansion Model for the Draft 2007 SOO scenarios.
- 10.5.8 I believe the Commission has fully factored-in Government objectives regarding renewable energy. The Generation Expansion Model assumes \$15/t carbon charges in the two thermal scenarios and \$40/t in the reduced demand and renewables scenarios. The Commission decided in November 2006 to weight the renewables scenario 40%, and the other three scenarios 20% each.
- 10.5.9 Having considered Transpower's submissions, advice from Commission staff and the various reports supporting the Draft 2007 SOO, I conclude that the scenarios in the Draft 2007 SOO present the reasonable future states of the electricity industry. The current drafts are detailed on the Commission's website under "Grid planning assumptions 18 December 2006". The scenarios show an average of 400MW weighted over all scenarios locating at specific sites in the Upper North Island by 2036. There is a further North Island need for 600MW of peaking gas, and 350MW of demand-side management and interruptible load in each scenario in response to emerging system capacity constraints and to firm intermittent wind generation. This is nominally located at Otahuhu, but I would expect much of the peaking gas generation to locate in the Upper North Island under the principles of the Generation Expansion Model, and for the demand-

side management and interruptible load to be dispersed around the North Island. Table 4 in the Commission Economic Report re-states this information on a North Island basis.

- 10.5.10 I believe that a reasonable estimate of new generation locating in the Upper North Island by 2036 is 1000 to 1200MW when averaged across the 4 scenarios, based on 400MW of site-specific generation already identified in the Draft 2007 SOO, 400 to 600MW of peaking gas and 200MW of demand-side management and interruptible load, noting that more than 60% of North Island load growth is expected to occur in the Upper North Island.
- 10.5.11 For generation beyond 2036, it is reasonable to assume new Upper North Island generation would emerge at the same average rate. That is, by 2042 a reasonable future state in the upper North Island is 1200 to 1450MW of new generation and demand-side alternatives.

10.6 Plausibility of demand scenarios

- 10.6.1 For the purpose of regulatory certainty and consistency with the generation scenarios, my initial inclination was to confirm the use of the Initial SOO scenarios, supplemented by a reasonable assumption regarding their extension to 2033. This was non-controversial.
- 10.6.2 However, if we are intent on reviewing the generation scenarios under clause 6.1 of the GIT in view of new information, for consistency we must also review the demand scenarios. New information includes:
- (a) the Draft 2007 SOO, in which the predicted demand growth is significantly less than that predicted in the Initial SOO; and
 - (b) the Draft New Zealand Energy Strategy that includes policies to promote energy efficiency as well as renewable energy.
- 10.6.3 It is relevant to observe from the Draft 2007 SOO investigations that the potential to harness firm renewable energy is limited, and there is a considerable need for thermal firming plant to support intermittent renewable generation. So much so, that New Zealand's portfolio of generation may continue to become more heavily weighted towards thermal. Greenhouse gas policy instruments may only be able to slow the trend away from renewables, and not reverse it. This observation highlights the growing importance of achieving efficient use and conservation of electricity.
- 10.6.4 Accordingly, a reasonable approach to the GIT analysis would be to adopt the Draft 2007 SOO demand scenarios as an upper bound and to acknowledge that electricity efficiency is likely to reduce the predicted rate of demand growth.

10.7 Unquantifiable costs and benefits not material

- 10.7.1 The Proposal included a number of costs and benefits in favour of the Proposal which could not be quantified. Clause 9 of the GIT allows material market costs and benefits which cannot be quantified to be considered by the Commission, provided their direction and likely magnitude are identified. The Commission has received independent advice and has consulted on some of these costs and benefits.
- 10.7.2 Having considered this information, my general conclusion is that the claims are so speculative as to be immaterial, and therefore do not qualify under clause 9 for inclusion in the GIT analysis.

10.8 Questionable need for a second substation in South Auckland

- 10.8.1 For the 220kV Alternative, Transpower has included as a modelled project a second substation in South Auckland requiring longer cables at the time of building a second 220kV line, on the basis that urbanisation will have made the Ormiston Rd substation inaccessible.
- 10.8.2 I have not been convinced by the argument that the alternative solution of early procurement of a corridor for a second 220kV overhead line to access the Ormiston Rd substation is unlikely to be feasible. Equally, I accept that there are risks associated with early corridor procurement, but many of those risks may be reduced by regulatory solutions currently being promoted by Transpower, and other risks may be able to be managed.
- 10.8.3 I note that the Minister for the Environment last August announced that “the Government has launched work on a nationally consistent framework to support and protect electricity transmission across New Zealand under the RMA”. The initiative builds on work of a reference group and “recognises the need to safeguard the country’s security of electricity supply”.
- 10.8.4 The corridor would need to be procured no later than the re-zoning of the land to urban uses. The holding costs of early procurement would be offset by any real inflation in land prices and by land use income. Historically, this has been a profitable strategy for landowners in peri-urban areas undergoing changes in land use, normally providing a return on investment of greater than 7%. For this reason, I believe it would be reasonable to assume that there is a nil net cost of early corridor procurement.
- 10.8.5 Historically, rural land has inflated faster than general inflation due to changes in land use and land use intensification, explaining Transpower’s assumption of a 3% real inflation rate for easement costs. Farm intensification is reaching a plateau. I accept Transpower’s 3% assumption on the basis that it may be a reasonable average figure over the length of the line, comprising of high rates of inflation where land uses are changing, and about nil elsewhere. This is

consistent with my assumption of a nil net cost of early corridor procurement in urbanising areas.

- 10.8.6 Alternatively, the subdivider may choose to pay the cost difference to underground, as happened with the ARI-PAK line through Botany Downs to Pakuranga.

10.9 Extension of a 400kV grid unlikely

- 10.9.1 The Proposal included strategic benefits regarding the extension of a 400kV system to the south of Whakamaru. The majority decision accepts these claims to the extent of crediting a \$3.5 million NPV benefit, on the assumption that the 400kV extension through the Central North Island would be required by the time the Proposal is energised to 400kV, enabling \$30 million of transformer costs to be saved.
- 10.9.2 The Commission was concerned about the plausibility of the roll-out of the 400kV “Grid Vision” and requested further clarification from Transpower. I was not persuaded by the explanations provided in their October 2006 and 17 January 2007 responses.
- 10.9.3 I think we can draw some general observations regarding the economics of a 400kV grid backbone from the investigations that have been undertaken for this grid upgrade:
- (a) The apparent economy of energising to 400kV compared with 220kV is negated by the cost of transformers required at each end of a line the length of the Proposal, as illustrated in Table 10.1.
 - (b) 400kV is only more economic than 220kV when the growth in power transfer is predicted to be high, or when the transfer distances are large.
 - (c) The economics of HVDC also improve with transfer distance in order to spread the cost of converter stations.
 - (d) The transfer capacity through the Central North Island (CNI) is currently very small in comparison with that from Whakamaru to Auckland, and Part IV of the 2005 GUP seeks approval for a significant increase in CNI capacity through thermal upgrades.
 - (e) The Initial SOO indicates only modest increases in transmission capacity requirements through the CNI. There is a reasonable likelihood that the planned thermal upgrades would be sufficient for some time.
 - (f) The SSG report, “Inter-area transmission capacity” (September 2006) undertaken for the Draft 2007 SOO identifies further large capacity increments are possible through duplexing and new 220kV lines.

(g) Even in an extreme scenario in which all new generation located south of Bunnythorpe, a 400kV Central North Island upgrade would be unlikely, as an HVDC link to Auckland appears to be more cost effective.

10.9.4 Therefore, my overall conclusion is that a 400kV grid backbone is unlikely, and that a 400kV Whakamaru to Auckland line is likely to be orphan technology. I cannot therefore attribute any value to 400/220kV transformer rationalisation.

10.10 Risk of double circuit failure in high capacity lines

10.10.1 Comments received during the Comments Period have expressed concern regarding the consequences of a double circuit failure of the Proposal when highly loaded at 400kV and conveying a large portion of the Upper North Island load. This issue is termed “grid resiliency” in the Commission Economic Report. This report explains that the risks of double circuit failure may be partially mitigated using special protection systems, but that their use in this situation may not represent good industry practice, given their questionable operability and dependability.

10.10.2 Transpower concluded, in their 17 January response to a request from the Commission for further information, that duplicating the Proposal before energising at 400kV would be a “*sensible option as it would allow more secure operation when conversion to 400kV occurs*”.

10.10.3 Table 10.1 above includes a comparison of annualised costs for various second-stage investments. I have included Estimated Unserved Energy (EUE) costs from the Commission Economic Report. Line duplication at 220kV appears to be the lowest cost. Line duplication at 400kV capability is more reliable than either the “energising at 400kV” options, and appears to be no more expensive. I accept that the economic comparisons are sensitive to the EUE assumptions embodied in the costs, but such sensitivities highlight the scale of the possible economic consequences of adopting a solution that may be considered less than good industry practice.

10.10.4 I am therefore of the opinion that energising at 400kV before line duplication is not reasonably likely.

10.10.5 This finding calls into question the need to model the second-phase investments, as line duplication is then common to both the Proposal and the 220kV Alternative. Whether a second substation is required in south Auckland or early corridor procurement is possible also become common to the Proposal and the alternative. The analysis becomes much simpler.

10.11 Duplexing of the A and B lines

10.11.1 In regard to another of the alternatives considered by the Commission, I consider that duplexing the existing Otahuhu-Whakamaru A and B lines has apparent attractions. It seems sensible to extract the full capacity of existing

assets before building new assets. Duplexing has been proven to be economic in other parts of the country. Transpower has not investigated this alternative to the same level of detail as the other alternatives, and as a result, has introduced significant uncertainty into the analysis. In my view a number of cost estimates put forward by Transpower are at best upper bound values. They are detailed below:

- (a) Easement costs that are similar for duplexing as for the 400kV Proposal seem to be implausible; the recent Environment Court decision on the *Fernwood Dairies* case should go a long way towards providing a firm basis for estimating easement costs for duplexing.
- (b) No consideration has been made regarding the relative RMA risks associated with new-build lines in comparison with duplexing existing lines, such as route extensions required to divert new lines around sensitive areas.
- (c) Tower and foundation works; the PBA report produced for the Commission has greatly assisted in clarifying the degree of tower strengthening required. They assessed in much greater detail than Transpower the C105 towers and found only modest requirements for strengthening. These towers are used over approximately 40% of the A & B line route and Cables towers are used for the rest. The latter towers appear to be stronger, given their wider bases and larger leg steel.
- (d) Undergrounding the existing line into Otahuhu as well as undergrounding the additional capacity; deciding to underground the existing line would constitute an additional benefit to duplexing. For comparative purposes it would be simpler to not account for the cost and benefit of undergrounding the existing line, as that option is available to the Proposal and all alternatives.
- (e) No allowance for the need to replace the existing conductor regardless of duplexing; Transpower stated in their 29 November 2006 response to the Commission that, "*Condition assessment reports show the conductor has a likely life of only between 10 and 15 years*". The date of those reports are not recorded, but it is apparent that the conductor will require replacement soon after the need date for an upgrade, regardless of which upgrade option is chosen.
- (f) No consideration in regard to the optimisation of the type of conductor so as to minimise the need for tower strengthening while maximising transfer capacity.
- (g) Operation and maintenance costs assigned to this alternative should only be the incremental costs arising from duplexing. One would therefore expect the O&M costs for duplexing to be considerably less than for the Proposal and the 220kV Alternative.

- 10.11.2 I can only make a tentative cost estimate of the impact of the above factors, given the paucity of available information. A reasonable reduction in capital costs from those presented by Transpower may be:

Table 10.2: Estimated capital cost reductions

Cost category	\$ million
Easement costs	80
Lesser RMA risks of new-build lines	up to 50
Tower and foundation works	20
Retaining overhead supply of existing capacity to Otahuhu	70
Saved replacement of existing conductor	10
Total	180 to 230

- 10.11.3 This is an NPV reduction of \$120 million to \$153 million, to which an O&M credit of \$19 million can be added for the existing structures and lines, making a total NPV reduction of \$139 million to \$172 million to Transpower's estimate for option 3.
- 10.11.4 In my estimation, the combined effect of the above would likely make duplexing a more economic option than the Proposal. I am uncertain as to how duplexing would rank besides the 220kV Alternative.

10.12 Modelling refinement

- 10.12.1 Figure 2 of the Commission Economic Report shows the distributions of need dates and commissioning dates for a second 220kV line derived from the Monte Carlo model.
- 10.12.2 For each need date, the graph indicates the frequency of Monte Carlo draws where the demand net of generation has equalled the secure transfer capacity.
- 10.12.3 To derive the commissioning date, the commitment date is first found using the same technique based on demand net of generation meeting 82% of the secure transfer capacity. The commissioning date is 5 years later, allowing for a conservative 4% compound demand growth rate (accumulating to 100% of the transfer capacity) and no local generation entering during that period.
- 10.12.4 Figure 2 shows that the commissioning date so derived occurs 8 years ahead of need on average. This is clearly conservative and would constitute inefficient project management.

10.12.5 While I believe the commissioning date assumptions used in the Commission Economic Report are reasonable, I think they are incomplete. In reality, not all elements of a project need to be committed 5 years ahead of need. There could be opportunities to delay some stages if circumstances change, such as new generation committing after the commitment date for the transmission project. There are opportunities to develop efficient transmission pricing or avoidance payments that would flush-out generation commitment prior to committing to construct new transmission lines. There are also opportunities to contract for short term transmission alternatives as contingency measures, including portable generation and demand management.

10.13 Impact on Net Present Value

10.13.1 An NPV comparison between the Proposal and the 220kV Alternative can be reduced to a comparison between their differences, which are:

- (a) The capital costs of lines, substations and series capacitors for the initial investment;
- (b) Modelled line projects to extend the life of the 220kV Alternative to that of the Proposal;
- (c) O&M costs; and
- (d) Cost of losses.

10.13.2 In order to estimate the cost of a modelled project to extend the life of the 220kV Alternative, I have referred to Table 7 of the Commission Economic Report. This indicates in the Draft 2007 SOO column for 'p50+gen' that the capacity of the Proposal operating at 220kV is expected to be exhausted in 2055, and the capacity of the 220kV is expected to be exhausted in 2051. I have assumed that the model line project to extend the capacity of the 220kV Alternative to that of the Proposal would be duplication of the 220kV line, and have applied its cost of capital at 7% over 4 years from 2051. I have discounted this cost to 2006 using the range of 7 to 12%, as discussed in section 10.4 of this opinion. Finally, I have inflated these results to take account of the distribution of need dates around the expected dates quoted above.

10.13.3 The cost of losses figure has been taken directly from Transpower's Application for Approval, adjusted by \$1.8 million as agreed between Transpower and Commission staff in January 2007.

10.13.4 The operation and maintenance cost difference is for lines only and adopts Transpower's assumption of 1.5% of capital cost per annum as an on-going cost from 2012 to 2055.

10.13.5 I assume the costs of cabling, voltage support, second-stage development options and unquantifiable costs and benefits are common to both options, or that differences are not material.

10.13.6 This set of assumptions allow the key variables to be exposed, and enables most of the complexity of the analysis to be put aside, together with the uncertainty that goes with it.

Table10.3: NPV results of Commission Pinnell

Element	NPV advantage to 220kV Alternative (\$ million)
Capital cost of lines, substations and series caps	40
Modelled project to equate capacities of options	-1 to -7
Cost of losses	-1
O&M costs	7
Total	\$39 to \$45 million

10.13.7 I conclude that there is a \$39 million to \$45 million NPV advantage to the 220kV Alternative over the Proposal.

10.14 Questions arising from this opinion

10.14.1 The following questions arise from my opinion:

- (a) Should the Initial SOO or Draft 2007 SOO demand scenarios be used? How should the potential for electricity efficiency be taken account of in the GIT?
- (b) What generation scenarios in the upper North Island represent reasonable future states?
- (c) Is it reasonable to assume that the costs of substations, cabling, voltage support and series capacitors are common to both the Proposal and the 220kV Alternative?
- (d) Is it reasonable to assume that duplicating the proposed line occurs prior to energising it at 400kV, and that the option value of energising to 400kV is so far in the future as to be immaterial?
- (e) Is it reasonable to assume that a corridor for a second line into the Ormiston Rd substation will be able to be procured?
- (f) Should a discount rate greater than 7% be used for costs and benefits occurring beyond the 20 year analysis period required by the GIT?
- (g) Do you believe that the alternative of duplexing the Otahuhu-Whakamaru A and B lines requires further investigation?
- (h) Is it reasonable to assume that the expansion of a 400kV grid south of Whakamaru is unlikely?

- (i) What is a reasonable set of modelling assumptions regarding the lead time for the commissioning date ahead of need date?

APPENDIX - Glossary

This glossary explains or defines specialised or technical terms used in this document.

AIS means air insulated switchgear.

Economic Reliability Standard describes the first limb of the GRS, whereby the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all economic reliability investments were to be implemented.

GIS means gas insulated switchgear.

HVAC means high voltage alternating current.

HVDC means high voltage direct current.

LRMC means long run marginal cost.

N-1 Safety Net describes the second limb of the GRS, whereby with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following any single credible contingency event occurring on the core grid.

N-G-1 Standard describes planning for one generator to always be out of service and allowing for an additional single credible contingency event.

Otahuhu B means the Otahuhu B combined cycle gas turbine generating station.

PE means pre-emptive load shedding.

SRMC means short run marginal cost.

Terminal Benefits means the then-present value of future benefits of a proposed investment or alternative project after the 20-year analysis timeframe.

Terminal Costs means the then-present value of future costs of a proposed investment or alternative project after the 20-year analysis timeframe.

Unserviced Energy Option means the option the Commission considered for a “base case” involving a “do nothing” approach, in which there would be no transmission or generation investment post 2010 and the system operator would pre-emptively shed load to maintain a secure system from 2011.