FINAL REPORT

Prepared For:

Transpower NZ Ltd

Transpower House, 96 The Terrace

Wellington, New Zealand

Analysis of Transpower's Proposed 400kV Project and Alternatives

Prepared By:

CRA International

Level 11, Mobil on the Park, 157 Lambton Quay

Wellington, New Zealand

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CRA Project No: D09448-00

Author(s): Erik Westergaard, Deb Chattopadhyay, Kelly McCall, Michael Thomas

DISCLAIMER

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1. INTRODUCTION

Transpower New Zealand Ltd (Transpower) has previously submitted to the Electricity Commission (EC) a Grid Upgrade Plan (GUP) including an investment proposal to construct a new 400kV double circuit transmission line from Whakamaru to Otahuhu. Transpower's proposal was submitted as a reliability investment. To be approved by the EC a reliability investment must meet the requirements of Rule 13.4, Section 111 Part F of the Electricity Governance Rules 2003[1].

The EC may approve a reliability investment if it is satisfied that the investment:

1. Reflects good electricity industry practice in meeting the grid reliability standards set out in the Electricity Governance Rules 2003;

2. Complies with the processes set out in the rules; and

3. Meets the requirements of the grid investment test, - by maximising the expected net market benefit or minimising the expected net market costs when compared with a number of alternative projects (Rule 6.3.4).

The EC found in their draft decision[2] that:

1. The proposal reflects good electricity industry practice;

2. Transpower has complied with the processes set out in the relevant rules; and

3. Alternative projects minimise the expected net market cost when compared with the Transpower proposal.

As a result, the EC turned down the request for approval, but indicated that it would undertake a review to provide stakeholders in the decision process an opportunity to make submissions before making a final decision in late July 2006. In addition, the EC noted that Transpower may amend its proposal at some future date.

Prior to the release of the EC's decision, Transpower had requested CRA International (CRA) to undertake an independent analysis of its proposed upgrade of the transmission system into the Auckland region and a limited set of alternative transmission projects. Transpower also asked CRA to identify issues with respect to the interpretation and application of the GIT that must be taken into account, or otherwise resolved, as part of the analysis.

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1 http://www.electricitycommission.govt.nz/pdfs/rulesandregs/rules/rulespdf/Part-F-16Feb06.pdf

2 Page 5, Draft Decision on Transpower's Auckland 400kV grid investment proposal, 27 April 2006. http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/400Kv/Draft-Decision.pdf

1.1. SUMMARY OF FINDINGS

We have arrived at two sets of findings which we discuss below: firstly, with respect to the GIT, and secondly with respect to analysis of Transpower's proposed 400kV investment.

We consider that the GIT as worded is, at best, an awkward description of what is, at heart, a straightforward cost-benefit analysis exercise that should be informed by overarching policy objectives. It would have been a more transparent, robust and consistent approach, had the GIT been formulated as a four-step process:

- Develop a common set of core assumptions between Transpower and the EC, soliciting industry input where necessary;
- Identify the sources of benefit that are to be incorporated in the analytic framework;
- Building on, but not being limited by, the Statement of Opportunities (SOO), analyse the costs and benefits to the extent deemed necessary to support a robust recommendation for near term expenditures and longer-term targets; and
- Consult on that recommendation.

It is clear that the GIT was developed in part as an attempt to constructively limit the scope and reach of an investment analysis and to focus it on what might be deemed as essential analyses. Fear of endless scenarios and sensitivities, convoluted methodologies and frameworks and untested or unaccepted assumptions may have led to the perception that proposing the GIT in its current form would somehow avoid all of those problems. To the contrary, in our view almost all of those issues have arisen anyway.

Nevertheless, if there is to be a GIT to guide the processes adopted going forward, then it behoves all stakeholders to focus on how the GIT is applied this first time. The first application of a new process or framework invariably sets precedent for future applications. The GIT is surely no exception. If there is to be long-term benefit from imposing constraints on the analytic process, then that process should be defined as wisely, prudently and cooperatively as possible. The implications of the GIT methodology for the achievement of broader policy objectives should also be more explicitly considered.

We do not present herein a comprehensive critique of the GIT, but propose interpretations with respect to several issues which are potentially contentious, and which need to be resolved in order to provide a basis for meaningful analysis and a workable decision-making process. We note that, by and large, the positions we have adopted, necessarily prior to the EC releasing its own views on those issues, are largely consistent with the directions which the EC's own analysis appear to have taken, as evidenced by the reports released with its current draft decision.

Having addressed issues with respect to the GIT, we then go on to describe the modelling approach and assumptions used in our analysis and to analyse the proposed 400 KV upgrade. We examine a range of proposals and alternatives, including:

1. The EC 220 KV upgrade in 2017, which in our study is compared against,

2. Transpower's proposal of 400 KV in 2010 but operated initially at 220 KV for the entire period of the study;

3. Transpower's proposal of 400 KV in 2010, initially operated as a double circuit 220 KV;

4. Transpower's original proposal of 400 KV fully operational in 2010.

We have also considered variation around these options with respect to timing of both the EC option and Transpower 400 KV options.

Our modelling of least cost expansion of the market identifies fuel cost savings and generation capital cost savings associated with each transmission option considered. We find that when compared to the EC 220kV alternative, the Transpower options show higher gross market benefits before consideration is given to the capital cost of the transmission options. Because of the time value of money assumption implicit in the requisite NPV analysis, the EC option, which is delayed until 2017, provides a superior net benefit to the Transpower alternatives, when transmission capital cost are accounted for. As a result, it is particularly important to assess the robustness of differences in benefits, costs and risks in periods prior to 2017.

Table 1 summarises the difference in net market benefit between the EC's 220 kV option and various Transpower 400 KV options taking into account the respective capital cost of each transmission option, and the timing of the capital investment, under various assumptions. Negative numbers in this table indicate that the EC alternative has a higher net market benefit (a lower net market cost) than the corresponding Transpower alternative it is being compared with. The estimates in the table reflect a comparison of least-cost scenarios (SRMC-based dispatch, with optimised generation entry).

Table 1: Net Market Benefit - EC 220 kV Option vs. TP Options ($millions discounted to 2006)

	Least Cost			
		Base Case Sensitivities		
EC 220 kV option built in 2017 vs.	**Base Case**	**SOO Generation**	**Higher Gas Price**	**Higher Hydro**
TP 400 kV in 2010 1 Circuit Operated @ 220 kV	-50.87		-56.02	-55.58
2010 TP 400 kV 2 Circuit @ 220	-41.43		-37.95	-27.66
TP 400 kV in 2010	-67.46	-37.18	-55.78	-40.12

Our least cost analysis indicates that with in service dates of 2017 for the EC option and 2010 for the Transpower options, the EC option is superior to all of the Transpower options. The option to construct a 400kV capable line and operate it at least initially as a double circuit 220 kV line is the most cost-effective option of those proposed by Transpower.

1.1.1. Sensitivity of Timing

A frustration of the GIT process to date is that refinement of options can be constrained by process considerations even as improved information becomes available. A consequence is that the value of flexible implementation can be overlooked. Consider, for example, that there is likely to be opportunity to defer the Transpower option and that there is risk that the EC option could be required earlier than indicated. Either of these adjustments can have profound impact on the relative benefit of the respective options.

For example, delaying construction of the Transpower options by two years (to 2012) reduces the difference between the Transpower alternatives and the EC 220 kV option to less than $10 million (a reduction of approximately $30 million). Given the many differences between these two options during the period 2012 to 2017, this cost differential must be considered small enough to merit intensive further review, both in terms of the assumptions applied and other differences that may affect achievement of broader policy objectives. Similarly, if the EC option is required two years earlier, all of Transpower’s options would have a higher net market benefit than the EC option. Without doubt, timing impacts are among the most important sensitivities to be considered when reaching a decision. It is commonly recognised that the risk to society of a bit too much infrastructure investment is less than the risk of a bit too little. The GIT is unclear, however, as to the appropriate weight to be given such considerations, even if they may be material with respect to the achievement of overarching policy objectives..

Table 2 : Least Cost Analysis Net Market Benefit - EC 220 kV Option vs. TP Options Delayed to 2012 ($millions discounted to 2006)

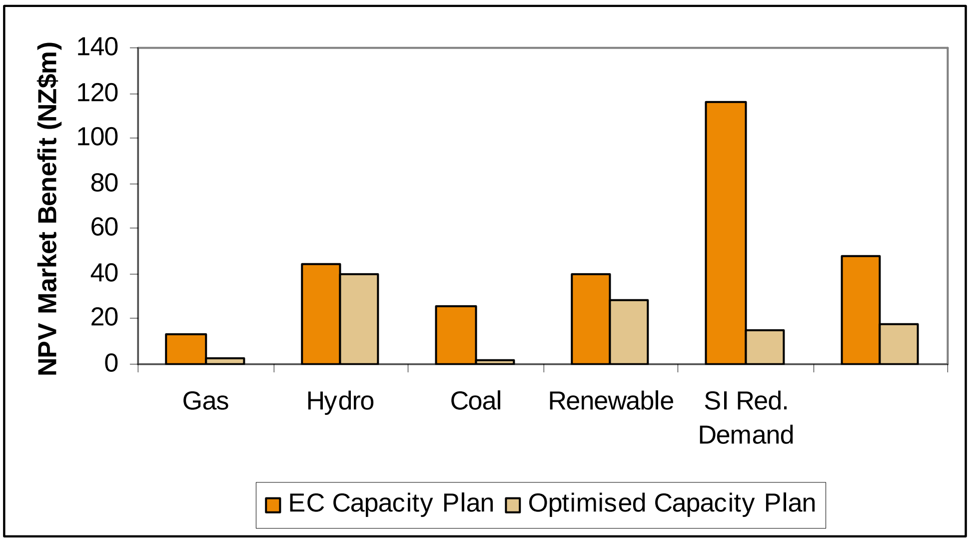
	EC 220 kV 2017	EC 220 kV 2015
TP 400 1 Circuit Delayed 2012	-16.71	19.75
TP 400 2 Circuit Delayed 2012	-9.44	27.02
TP 400 Delayed 2012	-36.04	0.42

1.1.2. Optimisation of the Generation Expansion Plan

CRA's modelling approach has optimized generation expansion using a combination of generation contained in the EC SOO and the introduction of generic gas fired plant as appropriate. Optimisation of the generation capacity plan to a given transmission development option is important. Failure to optimise the generation expansion plan to the underlying transmission plan being considered can yield misleading estimates of benefits, as we discuss further in relation to interpreting the GIT requirements.

To illustrate the impact of optimising generation investment in relation to a particular transmission proposal, we have also analysed the impact of relying only on the EC generation capacity development profile found in the EC's SOO to meet demand.

Figure 1: Difference in Market benefit of Transpower and EC projects with EC capacity plan and optimised capacity plan



The use of a suboptimal generation capacity expansion plan can result in either a higher or lower benefit to transmission (as compared to the benefit calculated against an optimised generation capacity plan) depending upon whether suboptimal excess or deficit capacity is located at the "export end" or the "import end" of the transmission configuration. The EC SOO generation capacity plan has more capacity at the export end (RNI/SI) and therefore the use of the EC SOO generation capacity plan results in greater benefits being estimated for transmission investments that enhance transfers to the Upper North Island (UNI) from the Rest of the North Island (RNI) or South Island (SI). As shown in Figure 1, the relative difference in gross market benefits between the EC 2017 220 kV option and the Transpower 2010 400 kV option is greater under the EC generation capacity plan. The use of an optimised capacity plan corresponding to the particular transmission option being analysed tends to reduce the value of transmission augmentation, and can be considered a conservative approach as compared to the use of the EC generation capacity plan without optimisation.

1.1.3. Competition Benefits

The EC has previously suggested that Competition Benefits (CB) might legitimately be accounted for in the GIT. However, the EC asserts that such benefits would be identical across all projects and would therefore have no influence on the final ranking.

The concept of competition benefits is not firmly established in the GIT, and is consequently subject to interpretation. In fact, different industry and competition regulatory bodies have implicitly adopted different interpretations, largely reflecting differences in the weight to be attached to options that result in lower prices to consumers, even if those resulting lower prices are a result of wealth transfers from producers rather than “net benefits” or a reduction in “deadweight loss”. We have interpreted the GIT as requiring a calculation of net market benefits, which implicitly refers to competition benefits that are net of wealth transfers.

Were it possible for those who benefit from transmission to fund a transmission project without regard to the fact that others may experience increased costs as a result, then a transmission investment could conceivably proceed that had immaterial or even negative net market benefits. Such outcomes can also arise in respect of generation investment and with respect to investment in most unregulated industries provided the investor is able to secure a contract from those who would benefit from the investment.

However, while the ability to secure a contract from beneficiaries of an investment to support that investment is not unusual, the ability to inflict material economic harm on other stakeholders that might be of concern to a regulator when doing so is not ordinarily expected in well functioning competitive markets. This is because such an investment usually results from prices above the competitive level and tends to move the market closer to the competitive solution (noting the market may in practice “overshoot” the optimal outcome, particularly where investments are lumpy and have long lead times). Thus care must be taken when considering the implications for regulated investment of focusing only on consumer surplus.

Our own analysis of competition benefits, using a Cournot model to simulate market based generation offer strategies, reaches a broadly similar conclusion to that of the EC with respect to competition benefits as shown in Table 3. However, we did note that the value of benefits attributable to possible improvements in competition vary across the SOO scenarios and transmission options. In general, the hydro, renewables and reduced South Island demand scenarios exhibit positive and material competition benefits for the Transpower options, whereas the coal and gas scenarios exhibit positive competition benefits to the EC option.

Table 3: Estimated Competition Benefit 2010 – 2040 - EC 220 kV Option vs. TP Options ($millions discounted to 2006)

	Average Benefit
TP 400 1 Circuit @ 220 kV	-39.04
TP 400 2 Circuit @ 220 kV	3.61
TP 400 in 2010	3.01

1.2. STRUCTURE OF THE REPORT

The remainder of this report is organised as follows.

In Section 2, we identify and discuss our main concerns with respect to the GIT, both in terms of how we believe the GIT should be interpreted and how it should be applied when undertaking the required evaluation of proposed transmission projects. In this section, we also discuss how we have adapted our analysis to address these concerns.

In Section 3, we present the analytic framework that we adopt, in evaluating a number of transmission options and provide details of CRA's model (CEMOS) used in the evaluation. In this section, we also discuss how we have adapted our analysis to address the concerns raised earlier and detail some of the data input assumptions underlying our analysis.

In Section 4, we present detailed modelling results

2. INTERPRETING THE GRID INVESTMENT TEST

2.1. INTRODUCTION

Since there are no precedents on which to rely when applying the GIT, we see this initial application of the GIT as setting important guidelines for future GIT applications, and as such, suggest that particular care must be taken when applying the GIT so that clear explanations are given with respect to the interpretations developed and analytic approaches applied. In this regard, we make a broad observation that the EC's analysis has generally been significantly more comprehensive in its reach than has been the EC's explanations of its reasons.

In the absence of historical precedents, the possibility of strategic gaming of possible GIT interpretations must be considered. The possibility also exists that some interpretations could introduce unintended biases. Faced with these risks, we stress the importance of grounding GIT interpretations and applications as clearly as possible in first principles, while leaving room for appropriately bounded judgment that reflects "common sense", "fairness", "good power system planning practice", and "the spirit of the rules".

Thus, in general, when evaluating transmission investment, we recommend the use of appropriate techniques, rigorously applied modelling approaches, experienced judgment and common sense reasoning, to determine the broad outlines of a transmission development strategy. More detailed analysis can then be developed for specific issues that are inherently more complex or are shown to be of critical importance to the decision to be made.

This is the approach CRA has taken in evaluating the GIT ahead of undertaking our analysis of the Transpower proposal and various alternative transmission proposals.

Because of their nature, neither the GIT nor the GRS contain a clear explanation as to the purpose of particular provisions, or why particular words or options have been chosen. Thus, we must infer what we can from the wording adopted and supporting material provided on the EC website, assuming that the overall purpose of these sources is to produce a workable, and effective, transmission planning process. The SOO is a very different document, being quite discursive in nature, and not tightly aligned to the GIT or Grid Reliability Standard (GRS) in its arrangement or terminology. The SOO is useful in that it provides guidance with respect to the interpretation that the EC is tending toward placing on the GRS and the GIT, and the types of issue that the EC appears inclined to consider.

More recent reports from the EC, released in association with its draft decision, have provided further guidance with respect to the EC's thinking on several issues[3]. We note that, in many respects, the EC appears to have adopted, at least implicitly, positions similar to those advanced here. However our modelling efforts, and hence our analysis of the GIT issues, necessarily had to commence well before those documents were available, and we make only limited reference to them here.

Finally, while the GIT may seem unclear and nebulous in a number of areas and may also be seen as being internally inconsistent on important points, this is not unexpected. The form of regulation that backstops the GIT is new in a New Zealand context, so there is not a long history of applications or decision making under the GIT and therefore little review and amendment of the GIT or its application. With continued attention, these issues can be resolved. However, in the meantime, the effect can be to slow the process down at a critical time when significant investment decisions must be made.

2.2. SCENARIOS IN THE GIT

The GIT uses the word "scenario" in subtly different senses, in various places. The key concept of scenario is found in the reference to "Market Development Scenarios" (MDS). According to Clause 28:

> ***"Market development scenarios"*** *means the reasonable future states of the electricity industry, developed for use in determining the* ***market benefits*** *and* ***costs*** *of a* ***proposed investment*** *and* ***alternative projects****, for each of:*
>
> *28.1. the future with a* ***proposed investment****;*
>
> *28.2. the future with each* ***alternative project****; and*
>
> *28.3. the future without the* ***proposed investment*** *or any* ***alternative project***

Now, it is unclear, in this definition, whether each such possible "future" is supposed to be regarded as a "scenario" in its own right or whether all the with/without variations associated with a particular base case scenario are to be regarded as forming a single scenario. The latter interpretation seems most consistent with Clause 17, which requires that:

> *In applying sensitivity analysis, a number of alternative reasonable scenarios should be developed for each of the* ***market development scenarios*** *using reasonable variations in all of the following variables…*

This seems to distinguish between "scenarios" in a general sense and ***market development scenarios*** in the sense defined by the GIT, with the former being variations on the latter. On the other hand, Clause 20 suggests that:

3 Particularly the "Economic Analysis Report"

> ***"Base case"*** *means the* ***market development scenarios*** *developed for the reasonable future state of the electricity industry without the* ***proposed investment*** *or any* ***alternative project****.*

This may be taken to imply that the base case is only one MDS set, with others to be developed as variations on that case, with and without various investments, as specified by Clause 28. In our view, the terminology is unclear. What is clear, though, is that the MDS set is supposed to contain a set of scenarios with and without the proposed transmission development, or any alternatives. And this is a much larger, and more complex, MDS set than that defined by the SOO.

Furthermore, we interpret the GIT as requiring that each such MDS is to be adapted so as to represent a reasonable projection of the market state with, or without, the transmission investment, or alternatives. This interpretation follows from Clauses 7, which requires that:

> *The* ***supply****-side of any* ***market development scenario*** *must include:*
>
> *….7.3.* ***modelled projects****.*

Where, according to Clause 29:

> ***"Modelled projects"*** *means transmission augmentation projects and* ***non-transmission projects****, other than the* ***proposed investment*** *and* ***alternative projects****, which are:*
>
> *29.1. likely to occur in a* ***market development scenario****;*
>
> *29.2. reasonably expected to occur in that* ***market development scenario*** *within the time horizon for assessment of the* ***market benefits*** *and* ***costs*** *of the* ***proposed investment*** *and* ***alternative projects****; and*
>
> *29.3. the likelihood, nature and timing of which will be affected by whether the* ***proposed investment*** *or any* ***alternative project*** *proceeds.*

In our view, these clauses place an explicit *requirement* on the investment proponent to include, in each scenario of the MDS set, modelled projects, both transmission and non-transmission, the nature and timing of which will be affected by the proposed investment, and which will therefore differ between the with and without scenarios, at least.

All of this stands in stark contrast with Clause 6.1, which states that:

> *The* ***market development scenarios*** *must be the possible future scenarios outlined in the* ***statement of opportunities*** *unless the* ***Board*** *determines that* ***market development scenarios*** *proposed by* ***Transpower****, the proponent of a* ***transmission alternative*** *or the* ***Board*** *are more appropriate;*

Clearly, the MDS set cannot "be" a set of scenarios specified in the SOO, if they are also required to include "with and without" MDS "scenarios", with modelled projects dependent on transmission proposals unrecognised in the SOO. In fact, this clause recognises that Transpower may propose an alternative MDS set, which will be acceptable provided they are "more appropriate". We would argue that the other clauses in this GIT effectively *require* Transpower to propose such an alternative set, which must, almost by definition, be 'more appropriate', if it includes modelled projects chosen to complement each transmission development plan considered[4]. In any case, Clause 6.1 is inconsistent with Clause 8.1, which requires that the "base case", which is either part of the MDS set, or perhaps the whole MDE set depending on which interpretation is taken….

> *… must be reasonable having regard to: ….*
>
> *… 8.2. any possible future scenarios outlined in the* ***statement of opportunities***

There is a significant difference between an MDS set being constructed to be reasonable "having regard to" the SOO scenario set, along with a great number of other factors, and actually "being" that set, as might appear to be required by Clause 6.1. Taking these two clauses together, and together with the rest of the GIT, we can only conclude that Clause 6 has been drafted with a slightly more restrictive view of what constitutes a "scenario" than has been assumed in the rest of the GIT.

Notwithstanding Clause 6.2, we argue for a broader interpretation of scenario for three reasons:

- First, it is more consistent with the detailed clauses in the GIT, which in accordance with general principles of legal interpretation thus implicitly nuance and limit the interpretations which can be placed upon a general clause such as 6.1;
- Second, the rest of the GIT is only workable, as a meaningful exercise in transmission system planning, if that broader interpretation is taken; and
- Third, this interpretation is more consist with the scenario concept, as understood in the wider literature on scenario planning where a scenario is generally described as providing some kind of internally consistent "world-view".

Finally, we note that Clause 6 of the GRS requires that

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

4 It should be recognised, though, that despite Clause 6.3, if Transpower meets the requirements laid down by later GIT clauses, its final MDS set will have considerably more alternative "scenarios" than the SOO set. But we suggest this is really just a problem with inconsistent nomenclature, rather than a difference in principle.

Thus it seems clear that a comprehensive engineering assessment of reliability must be presented when advancing a “reliability investment” proposal, covering the full range of relevant operating conditions, presumably including hydrological variations, plant breakdowns, load variations etc, which might be expected` to occur *having regard to the possible future scenarios set out in the statement of opportunities*. This phrasing, once more, suggests that the connection between the situations analysed and the SOO scenario set might actually be quite loose. But, at the very least, there is a clear requirement to perform studies of system performance over the whole range of operating conditions which might be expected given the system development assumptions of each scenario in the SOO scenario set, or any more realistic modification of that set which might be require.

Given the way in which the reliability standard is defined, as an n-1 standard without reference to USE, it is not clear that such a comprehensive analysis should necessarily be required to show that a project, or system, meets the GRS standard. Nevertheless, that kind of analysis clearly is required to determine the net market benefit of a project, and so we can only presume that it is intended that a similar level of analysis, with a more economic focus, should be performed under the GIT.

2.3. Scenarios in the SOO

In general, the general content of the SOO, and the directions of development, which it foreshadows are reasonable. Its interpretation of scenarios as internally consistent future worldviews, for example, aligns with our own. However, it should be recognised that this first SOO is quite clearly and consciously a transitional document. It explicitly recognises that it cannot yet take a form that might be envisaged as ideal, because:

- Some of the documents and policies on which it must be based are, or were at the time when it was prepared, not yet finalised;
- The EC has not yet had time to get all of its planned systems in place; and most importantly; and
- The logic of the transmission planning process must inevitably involve iterative cycling, and feedback between the SOO, and the GUP, to be approved each year as meeting the GRS and GIT

In recognition of this last point, the EC has developed in its initial SOO, its own assumptions with respect to transmission plans, which it believes, allow broadly plausible projections of market outcomes to be made under each of its various scenarios. It also makes it quite clear that these transmission upgrade assumptions have not been optimised, and that it expects Transpower to respond with its own transmission proposals, and if necessary its own scenarios.

This combination of processes and assumptions raises an obvious problem of circularity. If the EC chooses transmission upgrade plans to be assumed for each SOO scenario, however sub-optimally, and if it then optimises generation developments to match, however approximately,[5] the tendency would surely be for Transpower to discover that the apparently 'optimal' plan for each scenario was rather like the one which the EC assumed for that scenario. After all, in the limit, if the EC does its job well, that plan will be a perfect match for the generation scenario in the SOO.

Such circularity would undermine the integrity of the transmission planning process, and is surely not intended. In fact, it seems that the authors of the SOO have recognised this problem, but see it as unavoidable for this initial implementation. The proposals advanced by Transpower in any year would form part of the GUP, and this initial SOO announces the intention to base each future SOO, on the previous year's GUP. In outline, this seems an eminently sensible approach. At a more detailed level, though, we note some potential discrepancies, which may be more terminological than real, between what is proposed in the SOO, and what is specified by the GIT/GRS:

First, the transmission development plans assumed in preparing the SOO will have to:

- Extend well beyond the time horizon for which currently approved projects will be adequate to cover transmission requirements, and

- Be different for each SOO scenario.

Thus, the transmission upgrade plans assumed in preparing the SOO cannot simply be those set out in the GUP. An entire transmission development strategy must be specified, conditioned on the scenario set. Moreover, we do not think that it makes any sense for the EC to try to second-guess what Transpower's transmission development strategy might be, or to assume something different just for the sake of difference.

Accordingly, we suggest that the approach proposed in the SOO should be adopted, but extended on the understanding that it is not just the approved and committed projects which should be assumed in preparing the initial projections. Instead it should include the full scenario set developed by Transpower in advancing the previous year's GUP proposal, including modelled transmission developments appropriate for each MDS. This would not form a single transmission development plan, but rather a Tentative Transmission Development Strategy (TTDS), consisting of a set of plans, each appropriate to its own scenario, but containing a common core of elements that are proposed to be implemented in the immediate future.

5 Or vice versa

This TTDS would obviously be subject to scrutiny and challenge by the EC, as it is implicitly in the current process, but obviously not to the same extent as the GUP projects for which regulatory approval of expenditure is actually being sought. In addition, the version of the TTDS that is rolled forward to the next year would obviously have to reflect the decisions actually taken by the EC, in approving the GUP.

Some aspects of the situation will change too, from year to year. Load forecasts will differ, and perceptions may have changed with respect to the likelihood of particular scenarios or generation developments. Some transmission plans will probably have changed too, with projects slipping etc.

But it is suggested that such changes should only be modelled in the SOO if the EC feels that there is a compelling reason to propose a different TTDS, such as that the original schedule is now agreed to be unattainable. Otherwise, we will be right back into the situation where the EC is effectively second guessing Transpower's GUP proposals, its own response to those proposals, and consequential impacts on generation planning etc. This might produce more realistic market simulations in some cases, but it effectively undermines the role of the SOO in laying out the need for transmission developments.

We also suggest that the SOO scenarios, based on the previous year's TTDS, should be treated as the "base case" from which exploration of alternatives may start. We discuss this approach in the next section.

2.4. ESTABLISHING A BASE CASE

We have just suggested using the transmission system assumed in a SOO scenario as a base case, but note that this seems inconsistent with the current definition of "base case" in Clause 20 of the GIT, which states that:

> ***"Base case"*** *means the* ***market development scenarios*** *developed for the reasonable future state of the electricity industry without the* ***proposed investment*** *or any* ***alternative project****.*

On the other hand, the meaning of Clause 20 is unclear. Does it mean that, if a particular project is to be considered for approval under the GIT, the base case cannot include that project, or any alternative, at any time in any scenario? Alternatively, does it just mean that it cannot be included as a common element across all scenarios at the particular timing that is to be proposed? But then how is Transpower supposed to know what timing it will propose before it has done the analysis? And what is Transpower supposed to do when the transmission project that it wishes to propose, or some alternative to that project, has already been included in the SOO scenario assumptions?

This is not just a hypothetical question. If the EC constructs its SOO scenario set with due care, it is highly likely that it will include the kind of projects which Transpower would propose, albeit with variations on the timing. Moreover, if the SOO is based on the previous year's GUP/TTDS, this is almost certain.

In any case, leaving aside Clause 6.1 which suggests that the Transpower MDS set should actually "be" the SOO scenario set, apparently now including a whole set of assumed transmission developments, Clause 8 requires that the base case "*must have reasonable regard to… any possible future scenarios outlined in the statement of opportunities".* This will be difficult, if the base case must also contain neither Transpower's proposed development, nor any of the alternatives which are (most likely) assumed somewhere in the SOO scenario set.

On the other hand, we cannot expect the SOO to somehow specifically exclude the particular projects which Transpower might be expected to propose, or any alternatives, unless the intent is to provide a wildly unrealistic basis for projecting future conditions, as a kind of *tabula rasa* from which transmission/generation planning can start from scratch, each year. Nor does it seem sensible for Transpower to go to the effort of establishing and analysing an elaborate "base case" on that assumption. This could be quite ludicrous, particularly in the current situation where very substantial upgrades are being simultaneously proposed to various parts of the transmission grid.

Since choosing a "base case" really only amounts to placing that label on one of the cases to be considered, it seems to us that the only sensible way forward is to amend the base case definition in Clause 20. We believe it should be amended in favour of a definition that is compatible with the way in which transmission development options are modelled in the SOO. This provides a consistent reference point, around which variations can be explored.

Otherwise, we can only suggest that, if the GIT definition is to be adhered to, the SOO should be prepared assuming no transmission development at all, beyond that which has already been approved in the previous year's GUP. This too would provide a consistent benchmark, but one which might imply a requirement to re-do a large body of work each year, and seriously diminish the value of the SOO as an information document for the industry.

Either way, establishing a base case is not just a matter of "choosing" a transmission development plan for reference purposes. The base case scenario set must also be set up to represent a plausible future worldview, and to meet the requirements of Clause 8 in the GIT.

One of those requirements is that the accompanying generation investment pattern should be "reasonable" for that transmission (non) development scenario, having regard to a great many factors, including market conditions. Our experience suggests that, if meaningful net market benefit comparisons are to be made, it is critical that the generation development plans assumed in the base case be at least approximately optimal for each base case scenario, and likewise for each final MDS.

Otherwise, there is really no basis for comparison, it being quite likely that a sub-optimal transmission development will appear superior to an optimal one, just because it has coincidentally been paired with a more nearly optimal generation development plan. We suggested earlier, that if the EC does a good job of optimising its generation plans to its transmission development assumptions, the tendency will be for Transpower to find that the optimal transmission plan is the one that the EC assumed, because it matches the EC generation plans optimised to that assumption. But the situation is worse if the EC does not do a good job of matching generation to assumed transmission developments. In that case, even if the base case transmission developments were optimal, which might not be unreasonable if they are based on last year's optimised transmission development plans, Transpower is most likely to find that some other plan appears optimal because it better matches the (poorly matched) generation plans assumed in the SOO.[6]

Thus, we suggest that the first step in the analysis should be to re-calibrate the SOO scenarios by re-optimising the generation development assumed for each, especially if this has not already been done in preparing the SOO. This may be a significant task, given the transitional nature of this first SOO, but should not be unduly onerous in future years, given the approach proposed above.

2.4.1. Strategic Benefit of Transmission Upgrades

It will be evident that some decisions, such as the decision to initiate 400 KV development, may be regarded as more "strategic" than others. Thus, it seems relevant to ask whether the "strategic value" of such decisions can be properly accounted for by quantitative analysis. The answer depends subtly on how the scenarios are constructed. It also relates to the issue of what, exactly, Transpower is really seeking approval for, when it advances a transmission development "strategy", consisting of a set of plans for several scenarios. Is it seeking approval for:

1. The whole development strategy underpinning the GUP; or
2. Those specific elements in an application that must be undertaken at the present time.

6 It should be recognised that the same logical problem arises with respect to scenarios optimised by Transpower. Either way, the EFC must exercise vigilance in checking that, over time, generation developments are actually likely to follow the patterns modelled by Transpower. Rather than specifying projects to be assumed, the EC might like to specify, more explicitly, the cost/performance parameters which it believes to be reasonable for modelled projects under each of its scenarios

Our discussion above suggests that the answer should be “2”, and that the analytical approach of averaging across scenarios is valid under that assumption. That approach does not seem adequate if the whole strategy is to be approved, as in “1”, though. Even assuming the same level of care has been taken in preparing plans for each scenario, the basis for optimising plans within a scenario is essentially deterministic, and the averaging of cost and benefits from these very different plans across scenarios adds nothing to that deterministic assessment.

The scenarios that underpin analysis of options are supposed to be logically consistent projections of the future. This suggests that Transpower cannot select a preferred scenario, and plan on that basis. Rather, the industry will evolve in a manner consistent with one of the scenarios and Transpower will then have to adapt plans to fit that world.

The problem with this is that at some point in time you reach a balance point where a decision must be made to head down a particular development path – essentially a scenario has unfolded in sufficient detail to encourage adapting plans to fit. In announcing its preferred 400kV option Transpower is in effect, signalling that it believes it is at that point now and that the EC should, separately:

1. Approve 400kV as the new technology underpinning its proposed transmission development strategy

2. Approve an upgrade into Auckland using the approved technology;

3. Approve a date for the upgrade to be completed and in service.

The sequencing of decisions and the decision-making process may have a critical impact on the way in which particular scenarios develop. Load/generation response to market conditions will be muted in a climate of uncertainty around transmission options, and significantly sharpened once certainty is provided to transmission system developments.

This is likely to be most critical around both a decision on the transmission development strategy and a subsequent decision on the proposed commissioning date of proposed new transmission system elements. If the EC is to place any reliance on developments outside Transpower’s control, whether classified as “transmission alternatives” or not, the lead-time of those developments may well be critical. A year’s delay by the EC in announcing a commitment, either way, to transmission development may well lead to a year’s delay in any alternative coming on stream, with potentially disastrous results for system security and reliability.

Thus, a case should be made with respect to the timing of any commitment decision, as a factor in its own right, and somewhat independent of the proposed commissioning date of any particular investment.

Analytically, consideration should be given to the timeliness with which uncertainty might be resolved with respect to every possible future decision in every scenario. However, it is not obvious how this can be done, given that the transmission/generation planning sequence is effectively assumed to be deterministic within each scenario world. One possible option would be to treat the timing of the announcement as a separate decision variable.

However, there may be a problem here. Clearly, it would be reasonable for Transpower to assume that the sooner an announcement is made, the sooner the market will begin to adjust, and the lower future costs will be. This suggests that an early announcement can only bring positive benefits. Conversely, the EC may say that delaying any commitment might have positive benefits, because the longer the decision is delayed the more chance there will be to determine which scenario path is more likely, and the more transmission or alternative options may be revealed.

We suggest that Transpower and the EC should do some analysis to determine an appropriate trade-off with respect to the timing of decisions and the possible implications of getting the timing wrong. Not to do so would seem irresponsible, particularly in cases where the lead-time for development of transmission alternatives is becoming a binding constraint, so that the need to make an early announcement may actually be one of the most critical factors in the decision process.

While New Zealand should not automatically adopt regulatory arrangements used elsewhere in relation to transmission infrastructure investments, the approaches utilised in other jurisdictions with a considerably longer history of regulation can be instructive. Two noteworthy comments on approaches to transmission investment worth considering come from Victoria, Australia and Alberta, Canada.

Vencorp in their Vision 2030[7] document makes the comment

> "*Current regulatory approaches to network planning and justification of investment are still evolving. It is not clear that in cases where major capacity increases are potentially required, such as gas transmission in the South West corridor and electricity transmission in the Northern corridor, that current incremental "just in time" approaches will deliver a long-term optimum outcome. Specifically, there is risk of multiple parallel low capacity transmission links being built over time. A separate review of alternative planning approaches is warranted to ensure planning results in long term outcomes that best meet the needs of Victoria and its communities*."

The Government of Alberta in their Transmission Development Policy Paper[8] also reinforced this theme where they commented:

[7] Vision 2030 – 25 Year Vision for Victoria's Energy Transmission Networks, October 2005 http://www.vencorp.com.au/docs/Electricity_Transmission/Transmission_Planning/Exec_Summary.pdf

> "*Adequate transmission must be in place to support new generation. Transmission should not be a barrier to generation development - investors should be provided with certainty and confidence that transmission will be developed in a timely and adequate manner so that their product can be transported to market*."

There remains always an important role for cost-effectiveness analysis, but there are well-known shortcomings associated with many analytic approaches that can introduce bias inadvertently in even the most intentionally even-handed analysis. Two clear examples involve the calculation of WACC using the CAPM model and the use of NPV comparison when making significant capital investment decisions that involve potential flexibility.

The CAPM model is founded on a number of crucial assumptions that quite often do not hold sufficiently to accept "raw" output from a CAPM calculation. Only in recent years, has there been growing awareness of deficiencies in blind reliance on CAPM calculations to develop return parameters to support regulated infrastructure investment.

It has also only been in relatively recent experience that more widespread recognition that NPV analysis can understate the value of investments that embody significant optionality. There is even less widespread recognition and agreement as to what constitutes optionality, as the preponderant focus is too often limited to deferral value, when many other sources of optionality are potentially even more important.

Consequently, while it is crucial to have a robust evaluation framework, it is also important to have regard to the potential strengths and weaknesses of the analytic approaches and tools that are used and to compensate for those limitations where necessary. In this case, the full strategic option value of transmission upgrades and technology choices, or providing clarity to the market, may not be readily quantifiable by tractable optimisation techniques, but may yet be considered significant enough to legitimately influence decision-making..

2.5. ASSESSING COSTS AND BENEFITS

The basic analysis proposed under the GIT consists of a standard cost benefit analysis (CBA) and, while one may argue about details like the discount rate, this broad approach should not be controversial. Issues may be raised, though, with respect to particular components of that analysis, notably:

- Generation scenarios and related impacts on benefits;
- Non-supply costs; and
- Competition benefits.

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[8] Transmission Development The Right Path for Alberta A Policy Paper Alberta Energy Electricity Business Unit November 2003 http://www.energy.gov.ab.ca/docs/electricity/pdfs/transmissionPolicy.pdf

2.5.1. Generation Scenarios and Related Impacts on Benefits

The appropriateness of the assumed generation scenarios is obviously an issue. We believe this is perhaps one of the most important drivers of the benefits with the most obvious impact being inflating the unserved energy related benefits or energy savings if the underlying generation scenario is deficient in capacity, or sub-optimal.

We understand and appreciate the difficulty in establishing a set of benchmark generation scenarios that can be labelled as “reasonable”. However, we believe that the generation scenarios proposed in the SOO have a number of limitations that bring into question their reasonableness. Three out of five EC generation scenarios consider no capacity addition in the Upper North Island region beyond 2030 and the remaining two have very little addition. In addition, these scenarios are assumed to apply, even if there is no transmission system expansion.

We have already commented earlier on the need to account for interaction between generation and transmission developments. Consistent with that we would also interpret the GIT to require that the MDS set used in the analysis to be not only “reasonable” but also “appropriate” given the particular transmission development plan under consideration in each case. In our view, it would not be difficult to construct an MDS set which is, at least, more reasonable and appropriate than those which have been proposed to date.

In part, these anomalies can be worked around by simply comparing alternatives that deliver equivalent reliability to net out the impacts of generation deficiency. This is however unlikely to be an adequate approach unless the alternatives are indeed very close substitutes in terms of services. The greater other differences turn out to be, the more difficult it becomes to assess alternatives. We consider that the best option is to start from a base case plan that does meet the reliability criterion, and assumes balanced generation development to reduce USE to a realistic level.

More generally, as we have indicated at the outset, this being the first application of the GIT, we see this as an area that must be addressed directly. It is crucial to establish an implementation process and methodology that can be consistently applied for subsequent applications of the test. It will be important to recognise the key drivers that lead to a least cost investment plan as the GIT suggests including impact of hydrology, demand growth *and* the impact the incumbent transmission investment in itself may bring forth. The five-generation scenarios prescribed in the SOO may well be reasonable starting points, but it is how they respond to changing circumstances that matters most. Thus, the flexibility to define modelled projects and put a process in place to achieve this end within the broad GIT framework is crucial.

Finally, we also note that changes to the transmission system in the Auckland region will have impacts on generation development strategy at the national, as well as the regional level, and these impacts need to be accounted for appropriately.

2.5.2. Non-supply Costs

In principle, the economic justification of a "reliability investment" rests very heavily on the avoidance of "non-supply costs" but, practically, this is problematic because such costs are notoriously situation-specific, and hard to estimate. In part, this problem can be avoided by setting a security standard, and then searching for a 'least cost' way to meet that standard. However, that concept does not really avoid the problem either, because:

- One way to 'meet' a standard is "demand response", which brings us right back to ask what the cost of non-supply might be, albeit perhaps in a different form, more predictable and hence more benign; while
- Even for a reliability investment, it seems reasonable to net off the value of any market benefits delivered when determining the net cost of meeting the reliability requirement. However, those "market benefits" are also likely to involve a significant value component derived from "demand response" at prices indicative of some form of "non-supply".

hawse have previously expressed the view that there are fundamental problems with a regulatory regime that allows, or requires, costs/benefits of essentially the same type to be valued quite differently for different purposes. In particular the market establishes one set of values, while the EC has proposed another set of values in the GIT context, but implicitly uses quite another when assessing dry year security. That is not to say that all these values should be the same, because they may apply to very different situations, and imply very different economic costs.

There is obviously a very great difference between the disruption caused by an unexpected blackout, vs. a measured market response to an emerging shortage situation, via conservation and controlled DSM measures. It should be clear, then that it would not be appropriate to apply the EC's "unserved energy" values to all prospective load, which might not eventuate under some scenarios. Some of that "load response' should be, and probably has been, implicitly treated as 'market response", and valued at market prices, or perhaps even at SRMC fuel costs.

We have already discussed these issues and concluded that it is far from clear how these differing valuations can be consistently interpreted and applied within the context of the GIT. Although this aspect requires further thought and discussion, we will suggest a broad approach that at least reduces the problems, by minimising reliance on USE values.

As discussed earlier, the plausibility of the USE projected in the specified scenarios is also a major issue in this particular case, having major implications for the interaction between electricity market developments and transmission sector decision-making.

2.5.3. Competition Benefits

The EC has previously suggested that Competition Benefits (CB) might legitimately be accounted for in the GIT. However, we also note that at paragraph 7.5.1 of their report on the economic assessment of Transpower's proposal[9] the EC comment that:

> *The Commission believes that there is no need to estimate competition benefits in the present application of the GIT, primarily because each of the investments under consideration ultimately provide a similar transfer capacity. Hence, even if competition benefits were estimated and found to be substantial, they would be identical across all five projects and would therefore have no influence on the final ranking*

Not withstanding this comment, CRA believes that it is essential to address competition benefits in this analysis for two reasons. We address the issue firstly because it is important to establish basic principles of how competition benefits might be calculated in this first application of the GIT, and secondly because they can be material in some circumstances.

CRA believes CB to be the indirect effect by which increased competition:

- Increases allocative efficiency by forcing generators to offer closer to marginal cost
- Thereby increases productive efficiency by placing pressure on generators in sending regions, and consumers in receiving regions to reduce other costs, and possibly
- Increases dynamic efficiency by altering investment incentives in the long term

Accordingly, we believe that the focus should be on the benefits due to improved alignment between price and SRMC. Ultimately, CB analysis is about the way in which transmission expansion reduces gaming opportunities (i.e. improving competition).

There are two ways in which this could be conceptualised, and the choice between them depends, to some extent, on the way in which the available models can be solved. Market clearing models essentially assume perfect competition, and if the offers assumed in such models really do represent SRMC, they will estimate the prices expected to arise in a perfectly competitive market. If this logic is carried through into the capacity planning arena, the result will be a "least cost" estimate of market benefits.

Then, if the primary analysis is carried out in that way, the appropriate CB component may be calculated as the difference between solutions produced by a "gaming" analysis, optimised for each scenario and transmission option, and those from the primary analysis.

[9] Economic Assessment of Transpower's Auckland 400kV grid investment proposal – Prepared by the Modelling Group Electricity Commission, May 5 2006.

But, realistic market offers may often not be very close to SRMC, and an alternative analysis could be pursued, assuming offers based, say, on observations of current market behaviour. The problem becomes, though, how to adjust those offers to reflect the difference a transmission development might make to offering behaviour. Another way in which CB could be estimated would be to perform a basic analysis assuming continuation of current market offering behaviour, and then to estimate CB by taking the difference between that analysis and one performed with offers adjusted to match each transmission alternative, in each scenario modelled.

Conceptually, we suggest that this latter approach reflects more exactly the concept implied by the words “competition benefit” and we expect that it should always yield a positive CB estimate. But practically, we are not really sure what it means to say that “current offering behaviour” is maintained over all scenarios and alternatives, into the distant future. Nor are we sure what significance could be attached to the model results, noting that this would require assumptions to be made about offering behaviour of plant which does not yet exist, in situations involving various transmission upgrades or in principle, no upgrades at all.

There is clearly a matter for further debate here, and it may well be that different parties, using different analytical tools, may need to adopt different definitions of CB. We also note that the dependence of the CB definition on the assumptions in the underlying analysis may mean that CB estimates cannot be compared between analytical frameworks. It is unclear, for example, exactly what offer assumptions have been made in the EC analysis, and hence how CB should be defined relative to it.

We do note, though, that“CB”, assessed in this way, might actually be negative, even though transmission capacity expansion actually does enhance competition. This could arise if the benefits that expansion is predicted to provide under least cost assumptions are not delivered because gaming generators prefer not to fully use the new line capacity.

Cournot models have been used extensively for electricity market competition analyses.[10] Such analyses have typically focused on competition analyses to investigate generator-bidding behaviour, effect of market concentration and simulation of real-life markets to analyse spot price outcomes. CRA has used a Cournot model to analyse possible competition benefits arising from proposed transmission upgrades.

[10] See - A. Rudkevich and R. Rosen (1998, June 13), “Inquiry Concerning the Commission’s Policy On the Use of Computer Models in Merger Analysis”[Online]: http://www.tellus.org/energy/publications/ferc3.html and J.Bushnell, C. Day, M. Duckworth, R. Green, A. Halseth, E.G. Read, J.S. Rogers, A. Rudkevich, T. Scott, Y. Smeers, H. Huntington, “An International Comparison of Models for measuring market power in electricity” Energy Modelling Forum, Working Paper 17.1, March 24, 1999, Stanford University, CA

2.5.4. Reliability Standards and Defining the "Base Case"

It is important to determine the benchmark or base-case against which to compare the benefit or costs of the 400kV upgrade or proposed alternatives. Our understanding of the GIT is that:

- For "reliability investments" the base-case would always be some other project which also meets the reliability standards, whereas
- For "economic investments" the base-case would effectively be "do nothing", since none of the projects under consideration are necessary to meet any reliability standards.

The GIT states that the "base case" must not contain the proposed transmission project or any alternatives and also requires that it be realistic, and based on the scenario set presented in the SOO. For an economic investment, this does not raise any issues, but for a reliability investment, this clearly presents a problem. If it meets the GRS why is the base-case not one of the alternatives being considered? Indeed, this may imply that Transpower should propose that the "base case" be approved.

Also of concern is the interrelationship between projects and the GRS. If the 400kV upgrade option is to be compared with alternative projects that ensure the achievement of a transmission system built to an "n-1" standard, this raises significant issues around screening the other alternatives, including the transmission alternatives that have been short listed by the EC.

Although the emphasis of the GIT is on "projects", a "project" may not necessarily meet the GRS by itself. Perhaps the 400kV upgrade, when added to the existing grid, makes the system (n-1) secure but, in general, a "reliability investment" is one that is required as part of an overall package of measures designed to meet the standard.

Under our interpretation of the GIT, the proposed project must be part of a transmission development plan, or strategy, which meets the reliability standard specified in the GRS for each MDS. We also conclude that this plan must be compared with other plans that also meet the standard.

The choice of alternatives and the construction of consistent alternative transmission development plans are therefore highly important. It suggests, as noted earlier, that a decision on a transmission development plan must be taken prior to finalizing alternative transmission projects to be compared. This also implies a significant analytic burden to analyse transmission development plans ahead of analysing transmission alternatives.

3. PRACTICAL APPLICATION OF THE GIT

The previous section discusses several areas where CRA has some concerns with respect to the GIT and more importantly areas that are potentially problematic from an economic modelling perspective. In this section we discuss how several of those concerns have been addressed in our modelling and present the analytic framework that we adopt, in evaluating a number of transmission options and provide details of CRA's model (CEMOS) used in the evaluation.

3.1. GENERATION SCENARIOS AND RELATED IMPACTS ON BENEFITS,

As the location, timing and type of new generation is uncertain, the GIT requires the costs of a proposed transmission investment and alternative transmission projects to be estimated for a number of market development scenarios. These market development scenarios must include estimates of future generation investments. The EC has set out a number of generation scenarios in the 2005 SOO. In Section 2, we highlighted our concerns with the SOO generation scenarios.

A proposed transmission investment can meet the GIT if it maximises the expected net market benefit or minimises the expected net market costs when compared with a number of alternative projects. This suggests that a market-based approach to generation investment consistent with the SOO scenarios is required for evaluating projects. In undertaking our analysis, CRA has assumed that SOO generators will be connected to the system unless there is a cheaper alternative over the evaluation period. More generally, assessing the costs and benefits of a particular transmission augmentation should involve comparing a pair of scenarios with and without the transmission option and looking at:

- Consequential changes to generation investment plans;
- Consequential changes to later transmission development plans;
- Changes to generation patterns; and
- Changes in USE

Our proposed methodology involves application of CRA's CEMOS (CRA Energy Modelling Optimisation Suite) model and in particular, the long-term linear programming (LP) optimisation module called PEPPY. PEPPY comprises a capacity expansion optimisation model integrated with a dispatch simulation engine that can cover the entire range of analyses required, namely, it can:

- Optimise the capacity entry taking into account (high level) transmission constraints, demand side response and so on to meet demand over the years (represented using annual or seasonal load duration curves).;

- Have a reasonable operational simulation built into the model to assess performance of generation and transmission; and
- Provide all components of benefits readily, including:
  - Capacity deferral costs as the difference in capacity costs across the "with" and "without" transmission option scenarios. This will be calculated by the deterministic capacity entry module;
  - Reduction in energy costs as difference in generation costs (catering for transmission losses) with and without the transmission options from the operation simulation module; and
  - Unserved energy costs as difference in USE across the two scenarios from the operation simulation module.

The CRA model allows optimisation of generation to ensure that a least cost solution is obtained. This is achieved by allowing the model to select a generic plant over a SOO generator if it leads to a superior outcome. Further details on these plants are provided later in Section 3.

As a test of the optimality or lack thereof of the SOO we have also forced our model to develop new generation capacity according to the timetable set out in the SOO. Details of our findings are set out in Section 4.

3.2. DEFINITION OF UNSERVED ENERGY

As noted above, the GIT refers to USE in the context of transmission outages and values USE at $20,000/MWh. There is actually no suggestion that this value should be applied to energy which was not served as a result of an overall long-term shortage of generation or a failure to plan or build sufficient transmission capacity.

This suggests that some alternative arrangement needs to be instituted when either insufficient generation is being developed or transmission capacity is inadequate to meet demand. This alternative must surely value the energy produced to meet the load that would otherwise be unserved at a value less than $20,000.

To address this matter, in our modelling, we have assumed that sufficient new generation (generic plants) will be built to meet the demand for energy.

The use of generic plants largely eliminates USE in our modelling. The only time that it will occur is when the volume and duration of USE makes the price of energy from a generic plant more expensive than the $20,000 figure placed on it by the EC.

3.3. COMPETITION BENEFITS

To assess competition benefits we have developed a Cournot model to simulate generator behaviour and to assess the possible impact transmission upgrades may have on generator market power, i.e., less opportunity for the generators to set prices above their short run marginal costs.

Cournot competition requires that a market have a number of features. Table 4 below details the required features and compares them with the electricity industry. It may also be noted that the Cournot paradigm is widely found in the literature in which electricity industry competition issues are analysed.[11].

Table 4: Applicability of a Cournot paradigm in the electricity industry

Feature of Cournot Competition	Relevance to the Electricity Industry
There is more than one firm	Yes
Firms produce a homogeneous product	Yes
Firms do not cooperate	Yes
Firms have market power	Unknown but assumed may occur in certain locations under certain conditions
There is no entry	Yes - In the short term
Firms compete in quantities, and choose quantities simultaneously	Yes – NZ electricity market requires generators to offer capacity at prices and market clearing price
There is strategic behaviour by the firms	Yes – contract positions, energy limited hydro generation will encourage strategic behaviour
Contract positions restrain strategic behaviour	Yes
Energy limits constrain strategic behaviour[12]	Yes

11 A recent survey of the market power discusses the application of Cournot as the most popular choice. P. Twomey, R. Green, K. Neuhoff and D. Newbery, "A Review of the Monitoring of Market Power The Possible Roles of TSOs in Monitoring for Market Power Issues in Congested Transmission Systems" Cambridge Working Paper in Economics No. 71, 2006.

12 This is a not a feature of most Cournot competition models, but is a feature of the extended multi-period Cournot framework in T-CONE.

The basic theory behind the Cournot model of an electricity market is that each market participant acts to maximise his/her own profit taking into account price elasticity of demand and competitors' quantity offers. Solution of the Cournot game (or the Cournot-Nash equilibrium) is derived assuming the participants simultaneously choose their "best response" quantities to offer, with respect to the expected offer quantities of their competitors.

If a participant can unilaterally improve its position by changing its offer quantity then it will, and the equilibrium is found at the point at which no participant can improve its position (and make a greater profit) without others changing theirs. This point is referred to as a Nash-Cournot equilibrium. Extensions to the simple Cournot model can include the introduction of a price-taking fringe of smaller generators, an assumed order in which competitors place their offers or, as is the case in the model used by CRA, the imposition of constraints on transmission between regions of the market. [13]

The Cournot model developed by CRA International is named the Transmission-constrained Cournot-Nash Equilibrium (T-CONE) model. T-CONE models the strategic interaction among generating companies for a range of demand conditions (e.g., peak, off-peak demand across different seasons) taking into account their short run marginal costs, availability, energy limits and contract positions.

A more detailed description of the Cournot Model is set out in below. Details of calculated competition benefits are set out in Section 4.

3.4. DESCRIPTION OF CRA MODELS

CRA's CEMOS is a suite of modelling tools that are flexible to accommodate a range of features and issues in an electricity market. These tools comprehensively deal with a full range of issues in the electricity market including:

- T-CONE (or CONE[14]) Cournot-Nash Model: Gaming and determination of appropriate level of vesting contract and generator offer formation;
- PEPPY: LP-based capacity expansion and dispatch optimisation to determine long term entry/exit decisions; and
- STEMM: Engineering-economic issues in the short term.

13 Although some of these extensions can create situations in which alternative equilibria exist. T-CONE accepts the first equilibrium it finds, and does not attempt to explore any alternatives. This approximation seems reasonable since, in reality, the market is in a constant state of flux, and participants probably never do know for sure whether they have found any kind of stable equilibrium. The real test of this kind of modelling is how well it fits real market data, as discussed later.

14 The prefix 'T' in T-CONE denotes the application considers transmission constrained dispatch.

3.4.1. Application of CEMOS for Transpower

CRA has used PEPPY as the central analytic engine for long-term analyses of transmission options together with T-CONE for market-based offer formation to evaluate possible competition benefits of the transmission options. We have also used a variant of STEMM with detailed river chain and hydrology modelling to augment and assess the hydrological assumptions in our long term modelling.

PEPPY has been used as a stand-alone tool to undertake least cost generation expansion in conjunction with transmission alternatives being considered. In other words, generation and transmission options are co-optimised to minimise total system costs. Total system costs comprises capital investment in generation and transmission, fuel costs for generation, cost of dispatchable loads and unserved energy for all years in the planning period.

STEMM is a weekly simulation module that is set up to optimise short-term generation dispatch decisions under a range of hydrological inflow scenarios. STEMM has been used in the current application in a limited form mainly to calculate a distribution of hydro energy within a year for different hydrological scenarios and run-of the-river hydro constraint parameters for use in PEPPY/T-CONE.

The T-CONE offer creation module translates the Cournot Nash equilibrium outcome into a set of generator offers that are then used in PEPPY to optimise generation and transmission capacity and operational decisions in the long-term. PEPPY is also used in conjunction with market offers to provide a “market development” view of generation, in which generators are assumed to offer their generation above short run marginal / fuel costs. Generation capacity decisions and transmission investments are optimised as before to minimise total capital costs and generator offers to meet demand.

Both PEPPY and T-CONE use seasonal load duration curves (LDCs) to represent demand. We have used a 25-block per season and 10-block per season representation of the LDCs and determined the latter provides a reasonable compromise between model size (affecting solution time) and accuracy.

Unlike most Cournot models, which solve for an equilibrium in each period independently, T- simultaneously determines a consistent multi-period equilibrium, which can thus be constrained to respect inter-temporal limits on energy-constrained plant. This is crucial because otherwise it is not at all clear what SRMC should be used, particularly for hydro plant, in a Cournot analysis[15].

The transmission representation in PEPPY and T-CONE includes a DC load flow approximation of power flow and generic contingency constraints. We have incorporated a high-level approximation of the transmission network using a four-node representation (Upper North Island “UNI”, Rest of North Island “RNI”, Huntly, and South Island “SI”).

15 For hydro, this means that the model implicitly calculates an endogenous marginal water value. In principle, similar considerations apply to plant with, say, a coal stockpile or Take-or-Pay gas contract.

The flow constraints are represented using,

- MW transfer capability limits on each line
- Average loss factors
- Impedance sharing of flows around the loop in North Island formed by UNI, RNI and Huntly nodes
- (n-1) contingency constraints in the same loop as a linear relationship among the flows and Huntly node generation.

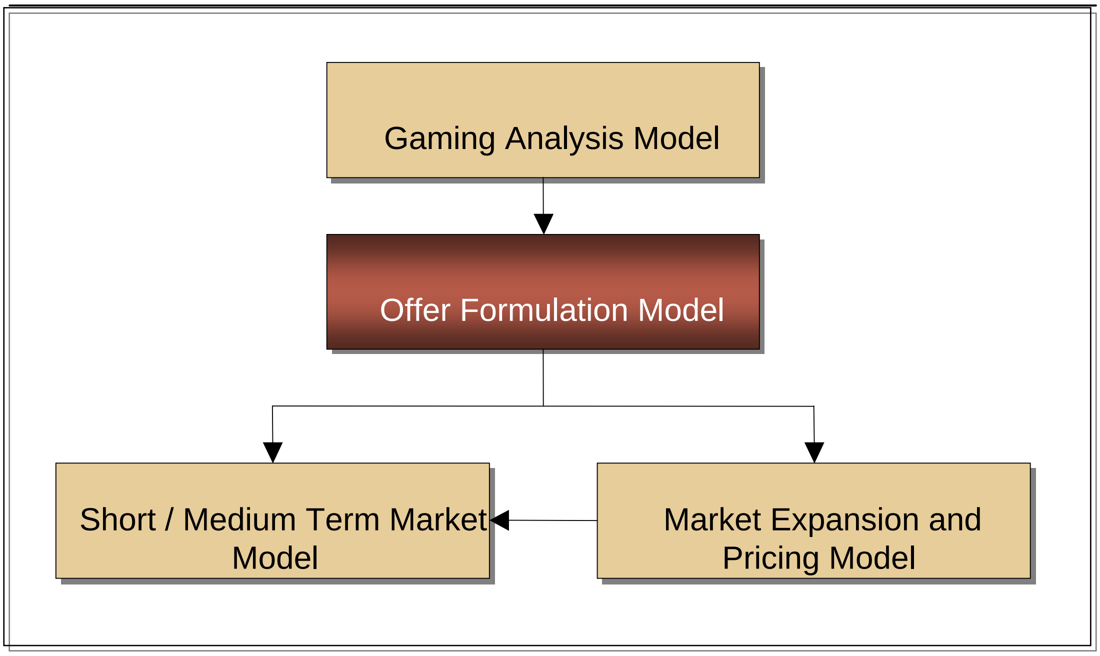
Other features include:

- Operating reserve in the model is represented as a minimum spinning reserve constraint in each island;
- Hydro generation output in both T-CONE and PEPPY is limited by an intertemporal energy constraint for each hydro station in each season. The energy limits are developed using the average hydrology capacity factors and potential GWh for new stations provided by the EC in the SOO. We determined the seasonal distribution of hydro energy and the distribution across the peak and off-peak periods within a season using STEMM;
- Capacity optimisation decisions in PEPPY form an integral part of the optimisation and are made in conjunction with generation, transfer, transmission investment and load dispatch decisions. The basic premise for bringing in new capacity is that system marginal costs (or "prices") should reach a level for the new generator to recover its fixed costs including (annualised) capital investment over all future years of operation. Capacity optimisation therefore recognises:
    - Demand growth and distribution of demand over seasons and peak/off-peak periods as captured by the LDC
    - Cost of capital and desired return as captured by the annualised capital cost that needs to be covered through market revenue
    - Operating/fuel costs or (if used in conjunction with T-CONE) generator bids that may be higher than fuel costs
    - Demand response as captured by (price responsive) dispatchable loads
    - Deterministic planned and forced outages that effectively put a limit on the annual energy production
    - Any additional limitation on energy production such as a fixed capacity profile for wind and geothermal energy, and hydro generators; and

- Transmission constraints including contingency constraints and to a limited extent spinning reserve requirements in the system.

In addition to using PEPPY to optimise capacity additions, we can also use the model to simulate other known capacity decisions such as committed entry or the generation plans developed by the Electricity Commission.

Figure 2: Overview of CEMOS Functionality



Short Term (Daily/Weekly) Simulation (STEMM)

STEMM is a short-term (daily/weekly) unit commitment model. It provides a framework to develop insights about the implications of the engineering characteristics of the gas/oil based existing/new units, shape of daily load curve and short term gaming behaviour/bidding strategies. The key features include:

- Detailed consideration of generating unit start-up/shutdown, ramping for energy/ancillary services
- Replicating, where possible, the market clearing process of the system;
- Chronological load profile;
- Transmission; and
- Ancillary services.

Longer Term (Several Years) Simulation (PEPPY)

PEPPY optimises the electricity market investment and operation over a number of years taking into account the physical realities of an electrical power system. It provides a framework to develop insights about the implications of the longer-term market drivers including future entry, longer-term effects of market power, effects of longer-term gas supply constraints, etc. The key features include:

- Detailed consideration of fuel contracts, load growth and its temporal/spatial distribution, new CCGT costs, vesting contracts;
- Replicating, where possible, the market clearing process of the system;
- Load duration curves;
- Transmission; and
- Ancillary Services.

Gaming Behaviour (Short and Long Term)

CONE is a model for analysing market power and competition in an electricity market with few competing firms or companies. Each company is assumed to maximise its own profit by adjusting its generation while considering the generation from all other companies and the demand responsiveness. This is known as a Cournot game, the solution to which comprises generation levels where each company has no incentive to adjust its supply because doing so would reduce its profit. Key features of the gaming module include:

- Strategic interaction among competing suppliers;
- Oligopolistic market behaviour;
- Cournot Nash equilibrium solution recognising;
  - short and long-term demand elasticity
  - peak/off-peak temporal load behaviour; and
  - inter-temporal energy limits;
- Bidding strategy can be;
  - built around the Cournot solution; or
  - developed to suit an alternative theory of behaviour.

3.4.2. Interaction among the CEMOS Modules

A key advantage of the CEMOS package is the complete integration of the different modules. Figure 3 shows how the results from each model can be used as input to another model.

Both PEPPY and STEMM can use the offers created by CONE. These offers are used instead of the SRMC of the generators. Both STEMM and CONE can use the capacity plan created by PEPPY. This allows for the optimal new entry determined by PEPPY to be used in these other models.

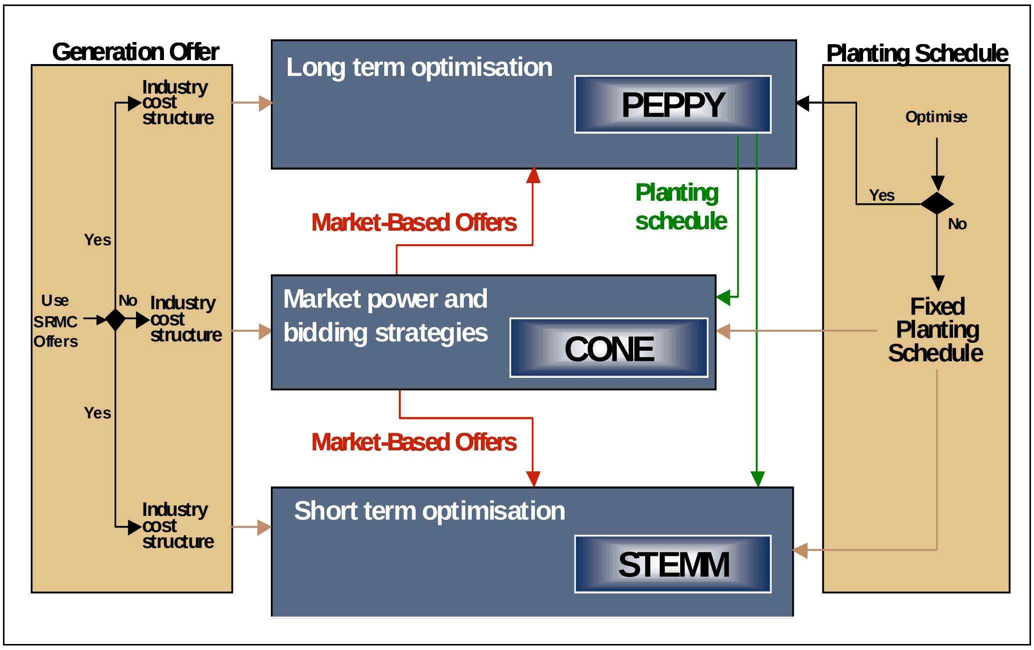


Figure 3: Interaction of CEMOS Components

3.4.3. Calibration of Cournot Model

Both PEPPY and STEMM can use the offers created by CONE. These offers are used instead of the SRMC of the generators. Both STEMM and CONE can use the capacity plan created by PEPPY. This allows for the optimal new entry determined by PEPPY to be used in these other models.

T-CONE relies on parameters such as elasticity and contract level for which no accurate estimate is available. This is because either quality data does not exist as in the case of elasticity, or the data exists but cannot be easily obtained due to commercial secrecy as happens to be the case with generation contracts. Since these parameters have profound impact on the outcome of the model including the generation level[16] – the only sensible way to establish a working model is to find out if the model can reproduce reasonable market outcomes within a plausible range of elasticity values that have been reported in the literature, and contract values that have notionally prevailed in the NZEM and other markets.

Calibration refers to the process by which we explore the impact of alternative levels of elasticity and contract values and compare the outcome in each case with observed market values. The basic hypothesis is that the market is generally heavily contracted for baseload generation and less so for peaking generators, and that low elasticity is associated with peak period volatility.

Within these broad guiding principles, the calibration process we use involves drawing up an *n*-dimensional grid of the combinations of potential values of the *n* parameters being estimated. Then, for each combination in the grid, a series of Cournot results is produced and assessed against the observed market data including observed generation data as to its goodness of fit. The basic premise is that if the model can reliably and reasonably accurately reproduce the market outcomes including generation, prices, market share etc using plausible values of elasticity and contract levels following the broad principles of how these vary with loading condition and generator types, then the model can be used with confidence to produce outcomes going forward if it is provided with the same inputs on elasticity and contract values.

We calibrated T-Cone based on the combination of (pseudo-) elasticity estimates (PED) and assumed (pseudo-) contract coverage (PCL) levels that yield the best fit to the observed price duration curves. [17]. Other important indicators assessed were the total GWh generation for the four seasons and the market share of the leading five generators in the four seasons.

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16 Cournot model use a price responsive demand curve and because price is determined via the quantity cleared, generation level determined by the model may vary significantly from observed demand level.

17 These are termed "pseudo-" values, because they are estimated from market data with the implication that market participants behave as if they were playing a Cournot game with these parameters. See J. Tipping, E. G Read, D. Chattopadhyay and D.C. McNickle "Can the shoe be made to fit? – Cournot modelling of Australian electricity prices" *ORSNZ Proceedings*, 2005.

A grid of contract levels and elasticities is developed to determine the combination that yielded the best overall fit to the observed price duration curves (PDCs). Because using the same parameter values across each block is arguably invalid, due to the existence of different contract levels and elasticities arising during the peak, shoulder and off-peak periods, the combination of values that yielded the best fit to the middle eight blocks of the PDCs was selected. These combinations are highlighted below in Figure 4.[18]

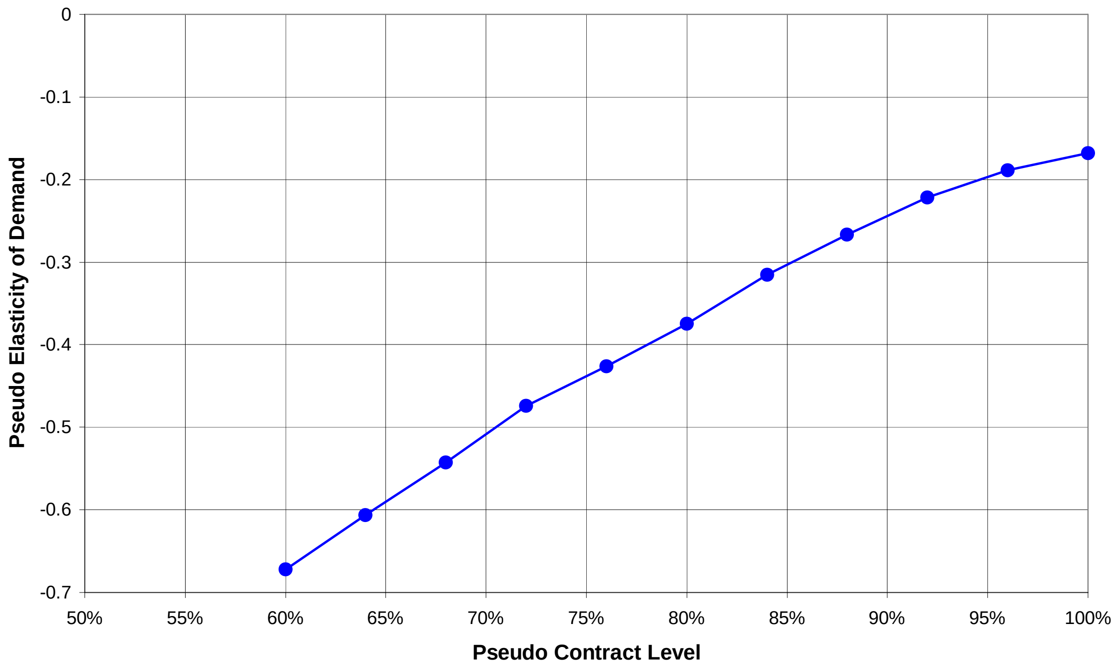


Figure 4: Combination of PED and PCL that yields the best overall fit to the observed PDCs

A final combination of a PED of –0.315 and a PCL of 80% was selected as these resulted in a similar total annual generation (37000GWh, as actually occurred in 2004 and similar market shares for the generators.

As mentioned earlier, the combination of PED and PCL selected provided the best fit to the middle eight blocks of the PDC. The values selected for each block, and the first and tenth blocks, were adjusted to further improve the fit of the PDC.

18 This empirically derived curve is basically linear, which seems to match the theoretical prediction at least for plausible elasticity/contract values.

The closeness of the fit to the observed PDC is illustrated in Figure 5. The dashed red line shows the average PDC across all three regions and four seasons. The dashed blue line is the average simulated PDC before the adjustments to each block's PED and PCL, and the hard red line is the average simulated PDC using the adjusted parameters.[19]

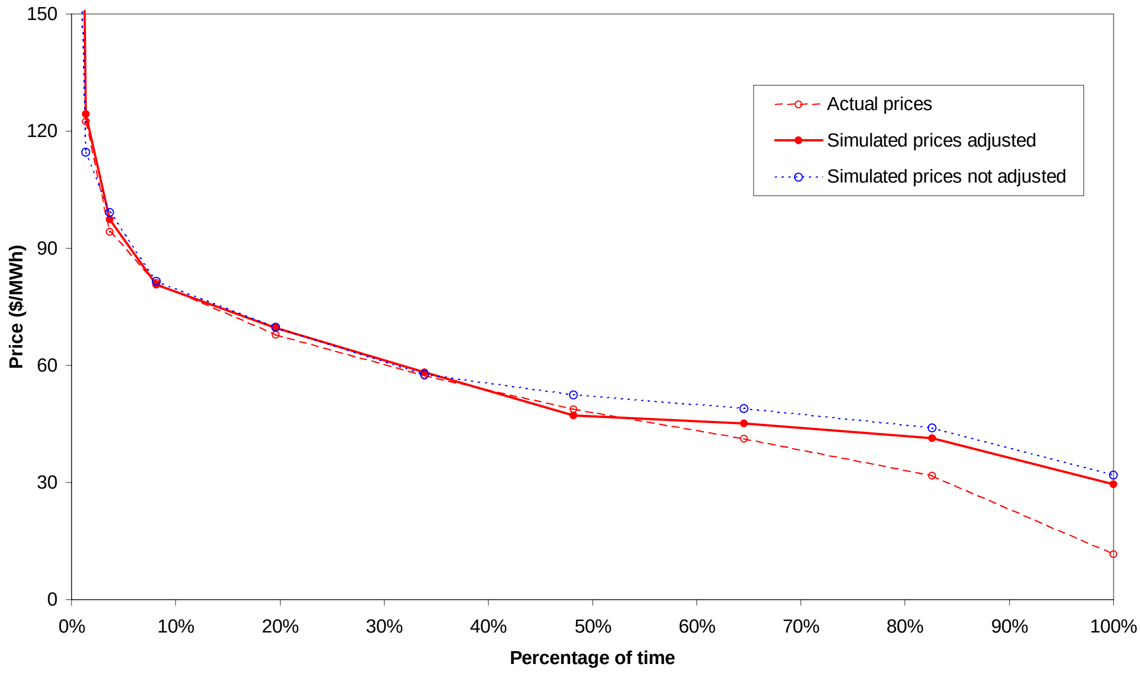
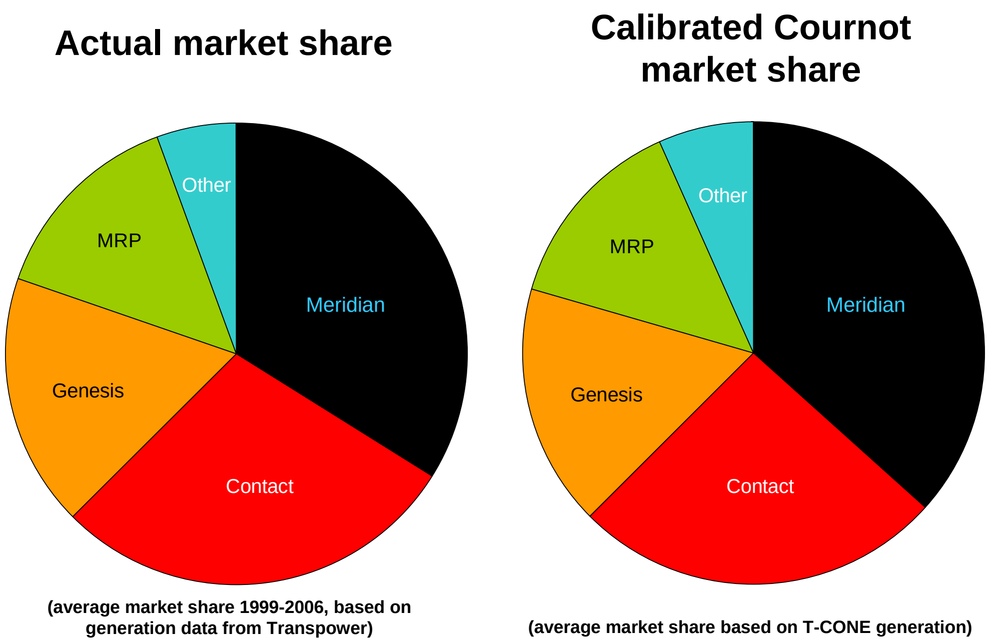


Figure 5: Average observed and simulated PDCs for the NZEM

Figure 6 highlights the actual market share with the share derived from the Cournot model outcomes. T-CONE reliably reproduced the market share for historical years.

[19] One thing that is noticeable in Figure 4 is that while peak prices are modelled well, the fit of the off-peak prices could not be improved greatly. We believe this result is probably an anomaly arising because the inflow sequence used by the model is that of an average hydrology year, therefore it may not be able to reduce prices in off-peak prices to the same extent as actually occurred in 2004, which was a comparatively wet year.

Figure 6: Comparison of market share 1996-2006 vs. Cournot



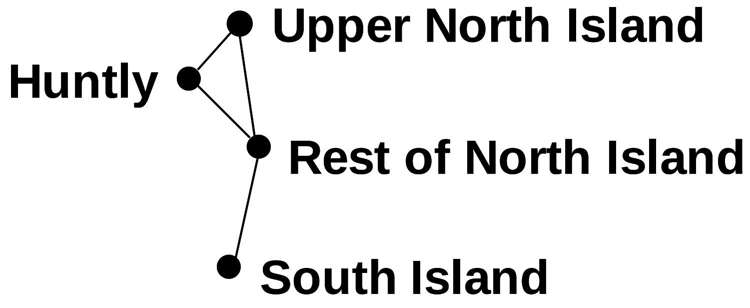
The resulting calibrated elasticity and contract levels also conform to the plausible range reported in the literature for elasticity values and the understood range of contract coverage prevalent in the electricity industry in New Zealand and elsewhere. The model can reasonably and reliably produce the price, dispatch/market share outcomes observed in the past.

3.5. Modelling Input Assumptions

3.5.1. Transmission Representation

CRA has developed a four-node representation of the New Zealand transmission system to allow modelling of the benefits of alternative upgrades to the transmission system. Figure 7 provides a diagrammatic representation of the grid model adopted.

Figure 7: Grid Representation



UNI is used to represent the Auckland and Northland region and is the point of connection for the existing Otahuhu, Southdown, and Glenbrook generation stations. All additional UNI generation outlined in the EC's generation development scenarios and assumed to be constructed in the Auckland region is modelled as being connected at this node. Given the scale of Huntly generation and the complexities of transmission circuits between Huntly and both Otahuhu and the RNI a separate node is used for Huntly. Whakamaru is used to represent the RNI and all new North Island generation not included at Otahuhu is assumed to be connected at this node. The SI is represented as a single node.

Generic Constraint Equations - a four-node transmission representation simplifies the actual interactions between system components that take place on a transmission system. To overcome the power flow implications of multiple transmission circuits being represented by a single branch, a number of constraint equations have been developed. These equations express the relationship between transmission circuits within a branch and between branches. The model utilizes both

- **Branch constraints** – setting the limit for each branch via the "branch rating", and
- **Group constraints -** used for modelling the flow interaction between each branch.

Each transmission alternative modelled is represented by separate branch and group constraint equations. Transpower has provided these constraint equations to CRA.

Transmission Losses - Differences in transmission losses between the transmission nodes are an important benefit from upgrading the transmission system. For the purposes of the modelling, a single loss factor is used for each branch, rather than a quadratic flow-loss function. The CEMOS model allows for a multi-tranch loss function where appropriate. Calibration of the model has shown that given the simplified transmission network utilized, a single loss factor vs. a three-tranch loss model does not give materially different outcomes. Separate loss factors have been calculated for each of the different 400 KV upgrade options and for the EC 220 KV option. Loss factors provided by Transpower are set out below.

Table 5: Average Loss Factors (%)

			Average Loss Factor (%)			
Options	**Case**	**Season**	**Otahuhu-Whakamaru**	**Whakamaru-Huntly**	**Huntly-Otahuhu**	**HVDC (inter island)**
1	Existing (2010~2040)	Winter	5.73	2.76	2.85	7.5
		Summer	5.73	2.76	2.85	7.5
2	EC 220 kV(2010-2016)	Winter	5.73	2.76	2.85	7.5
		Summer	5.73	2.76	2.85	7.5
2	EC 220 kV(2017 onwards)	Winter	4.06	2.76	2.85	7.5
		Summer	4.06	2.76	2.85	7.5
3	400 kV 1 Circuit @ 220 kV	Winter	4.85	2.76	2.85	7.5
		Summer	4.85	2.76	2.85	7.5
4	400 kV 2Circuits @220 kV	Winter	3.76	2.76	2.85	7.5
		Summer	3.76	2.76	2.85	7.5
5	400 kV (2010~2040)	Winter	2.82	2.76	2.85	7.5
		Summer	2.82	2.76	2.85	7.5

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Grid Security Standard - We have assumed an N-G-1 grid security standard. This standard is reflected in the constraint equations used.

Transmission Capacity – Transpower has provided the transmission capacity of both existing and new transmission lines. Specific details of the transfer capability of the modelled transmission alternatives are set out in Table 6 below

Table 6: Summary of Transmission Options and Summer and Winter Branch Transfer Capacity

			Transfer Capacity - MW			
			Otahuhu-Whakamaru	Whakamaru-Huntly	Huntly-Otahuhu	Total into Auckland
Options	Case	season				
1	Existing* (2010~2040)	Winter	532	644	1953	2485
		Summer	483	529	1790	2273
2	EC 220 kV(2010-2016)	Winter	532	878	1953	2485
		Summer	483	805	1790	2273
2	EC 220 kV(2017 onwards)	Winter	1456	878	1953	3409
		Summer	1320	805	1790	3110
3	400 kV 1 Ckt @220 kV	Winter	885	644	1953	2838
		Summer	804	529	1790	2594
4	400 kV 2Ckt @220 kV	Winter	1308	644	1953	3261
		Summer	1186	529	1790	2976
5	400 kV D/C (2010~2040)	Winter	1802	644	1953	3755
		Summer	1634	529	1790	3424

*Assumes Huntly East and Otahuhu-Whakamaru A&B upgrades

3.5.2. Generation

In modelling the benefits of transmission upgrades, a number of assumptions have been made about generation options. The modelling considers three types of generation; existing plants, new generation as set out in the EC Statement of Opportunities (SOO), and Generic plants. Appendix B provides details on all plants modelled.

1. **Existing Plant** - All existing plant is modelled and assumed available for the full period of analysis. No allowance has been made for the possible retirement or derating of existing generation units.

2. **Electricity Commission Plants** – Details on this plant has been obtained from the EC's SOO. Each of the five SOO generation scenario's (Gas, Coal, Hydro, Renewables, and Reduced demand) are considered in the analysis. East Harbour Management Services have supplied estimated capital costs of EC plants updated to April 2006.

3. **Generic Plants** – generic plants (CCGT and OCGT) are used to provide additional capacity when the demand for energy exceeds available production from existing and EC scenario plants. The use of generic plant largely eliminates the occurrence of unserved energy. East Harbour Management Services have supplied estimated capital costs of generic plants. In addition, we have assumed that there is a limit on the amount of new generation that can be located in the Upper North Island region due to constraints on gas availability. Generic plant additions in the UNI region are limited to 700 MW of new capacity.

Table 7: Generic gas power station characteristics

Plant Type	Capex Cost (NZ$/kW)	Heat Rate (KJ/kWh)	Life – Years
OCGT (250 MW)	1,000	9,300	25
CCGT (400 MW)	1,200	7,200	25

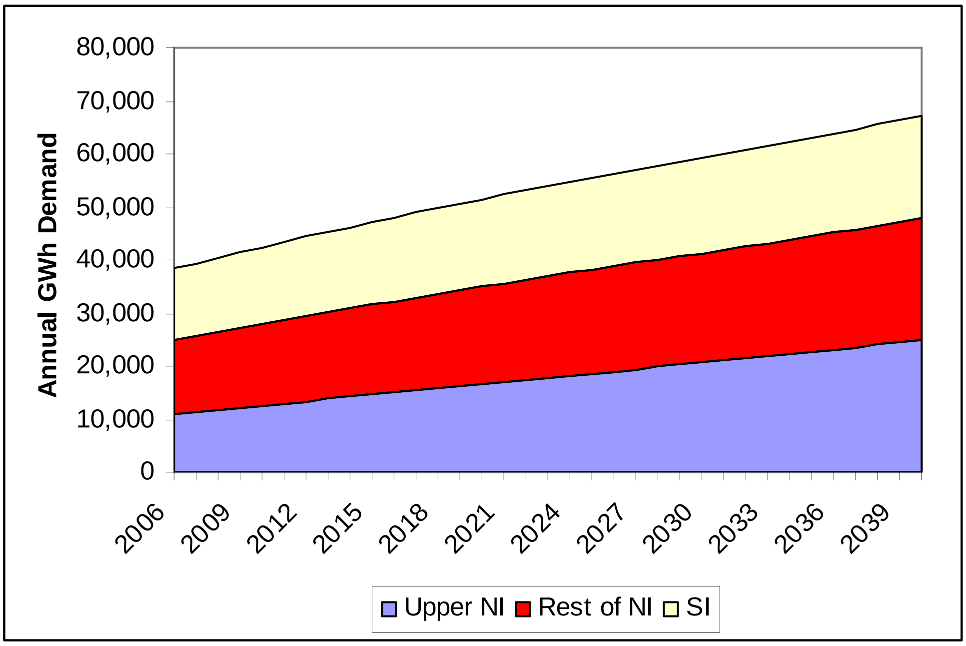
Plant Constraints – All hydro generation both existing and new as per the SOO is assumed to be energy limited. Energy limits are based on EC SOO data.

Fuel Costs – Fuel price projections are sourced from the Ministry of Economic Development's (MED) report "New Zealand's Energy Outlook". Details of the respective fuel costs are set out in Appendix B. While these forecasts have been prepared by the MED with the best available information, the prices are more likely to be too low than too high given international trends in gas prices. To address this concern sensitivity analysis has been undertaken on fuel costs. In this sensitivity analysis we have assumed that gas prices are approx 40% more than the MED forecast – NZ$12.00 rather than NZ$8.50. While this may appear pessimistic, it is not unrealistic given international trends in world oil and gas markets.

3.5.3. Demand and Load Growth

Load Growth – Electricity load growth has been based on the EC's medium growth scenario. This scenario assumes that the energy (GWh) requirement grows at 1.7% per year. Our analysis considered seasonal variation in demand but applies the same annual growth rate across the seasons.

Figure 8: Forecast energy growth in New Zealand regions



Load Duration Curves – Rather than modelling 8760 hourly periods for each of the 40 years modelled, a simplifying approach utilising load duration curves has been used. An annual load duration curve was developed for each year based on forecast load growth and a historical load duration curve. Each year's load duration curve has then been divided into 10 segments, for use in place of the hourly load data. We have also checked the sensitivity using a 25 block per season (or, 100 per year) demand curve and concluded that 10 blocks provides a good compromise in terms of computational speed and accuracy.

3.5.4. Transmission Options Modelled

A proposed investment meets the GIT if it reasonably satisfies the EC Board that it is required to meet the grid reliability standards and if

> … 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; …[20]

In undertaking this analysis, CRA has considered four different transmission alternatives at the request of Transpower, each of which are discussed briefly below.

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[20] Part F Section 111 Schedule F4 Rule 4.1.1, Electricity Governance Rules

1. 400 kV 1 Circuit @220 kV installed 2010 – this alternative assumes the required line is built as a single circuit 400kV line but initially operated at 220kV. Additional investment will take place to add additional transmission capacity on a staged basis. It is assumed that additional investment will take place in 2015, 2017, 2020, 2027, and 2030 – see Appendix B for capital cost details.

2. 400 kV 2 Circuit @220 kV installed 2010. – this alternative assumes the required line is built as a double circuit 400kV line but initially operated at 220kV. Additional investment will take place to release additional transmission capacity on a staged basis. It is assumed that additional investment will take place in 2015, 2017, 2020, 2027, and 2030 - see Appendix B for capital cost details.

3. 400 kV double circuit installed in 2010 – this is the project originally submitted by Transpower for approval by the EC in their September 2005 Grid Upgrade Plan. It assumes the line is constructed and operated at 400kV from 2010 - see Appendix B for capital cost details.

4. EC 220 kV – this option assumes that the required line is constructed at 220 kV rather than 400kV and assumes that it will be in service from 2017 rather than 2010 as with the previous options. This option also assumes that certain other investment will be required in the existing transmission system to ensure that sufficient capacity is available on existing lines to meet an N-G-1 reliability standard between 2010 – 2017 - see Appendix B for capital cost details.

3.6. SENSITIVITY ANALYSIS

Sensitivity analysis has been undertaken for those variables that are likely to have a significant impact on the Net Market Benefit of the transmission options under consideration.

3.6.1. Demand

For our base analysis, the EC’s medium growth scenario was used. Higher or lower growth than the medium growth scenario may impact on the quality of the decision reached.

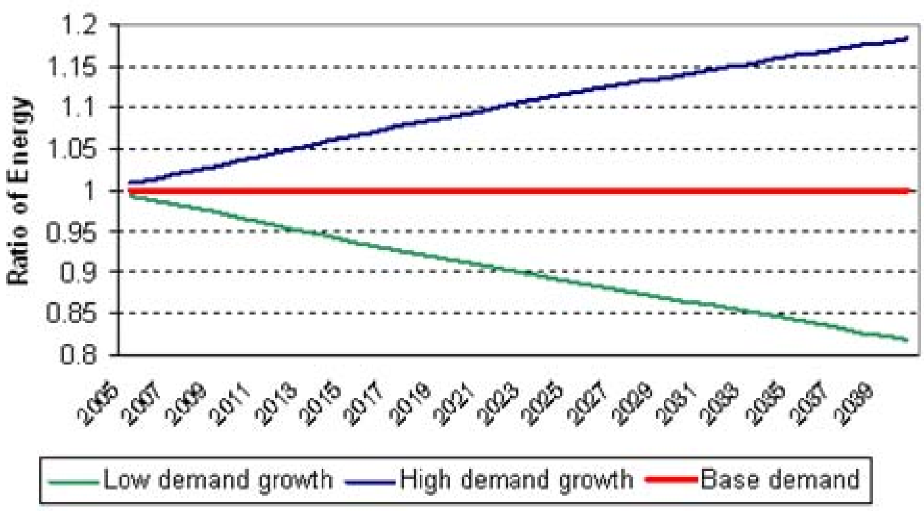
There are no ramifications of lower growth if the decision reached is to turn down an application – arguably, the right decision was reached. However, if a decision is made to approve a project and growth is less than forecast then a project will be commissioned early and consumers will end up paying more than may otherwise have been necessary. Such a decision would not reduce reliability, just cost-effectiveness.

Conversely, if demand is higher than expected and the decision taken is to turn down an application, potentially serious consequences may arise. Reliability of the power system may be compromised as a result of transmission capacity having been deferred. This may manifest in the extreme with unserved energy potentially valued at up to $20,000/MWh or through higher fuel costs because a lower cost generation portfolio to meet this higher demand is unable to be constructed due to a lack of transmission capacity

The asymmetry of outcomes is an important feature of decisions of this type. Where strong asymmetric impacts exists, the prudent decision typically involves targeting a higher probability of having built too much capacity than of having built too little.

Our analysis has considered two demand growth paths provided by Transpower around the baseline demand forecasts in EC's Statement of Opportunity. Figure 9 shows the ratio of annual energy for high and demand growth sensitivities with the base energy forecasts. We have assumed the shape of the load duration curve remains the same for the sensitivity cases as in the base demand growth scenario.

Figure 9: Ratio of annual energy for high and low demand growth sensitivities with the base energy demand



Source: Transpower

3.6.2. Hydrology – Wet and Dry Years

We have modelled an average hydrology and variations around it for (extreme) dry and wet sequences. Our approach has been to test the sensitivity of benefits under alternative hydro assumptions to assess the maximum variation that is expected from an average hydrology, rather than a detailed examination of all historic inflow sequences.

We have constructed hydrology scenarios assuming a maximum of 20% hydro inflow variation on either side of the average hydrology scenario that we used in our base case assumption. This implies a range for hydro release from 20,000-29,000 GWh for each year with 20,000 GWh yield in the dry year sensitivity and 29,000 GWh in the wet year sensitivity.

3.6.3. Gas Price

All generation scenarios result in some gas fired generation being built, either as part of the scenario or as generic plant necessary to balance supply and demand. Our base case analysis has adopted the gas prices contained in the MED's 2006 Energy Outlook.

Commentary has been made about future uncertainty around oil and gas prices due to concerns about availability and demand. If gas prices assumed in the MED report are optimistic – lower than those that actually occur over the analysis period, then more gas fired generation may be constructed close to the load rather than more remote alternatives such as hydro or other renewables. Such a situation would lead to a possible overstating of net market costs associated with a reliability investment, thereby understating the value of transmission upgrades

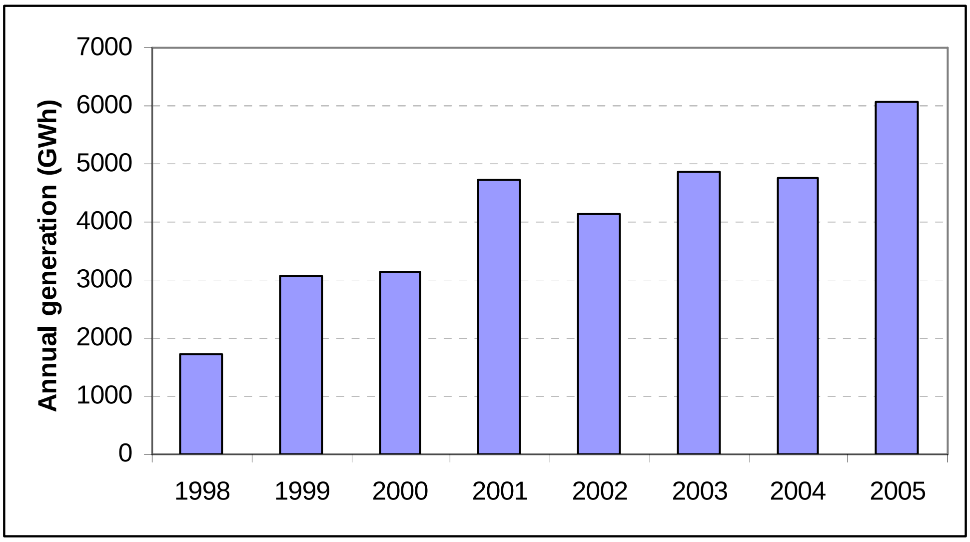
Accordingly, gas price is treated as a sensitivity in our analysis. We have considered a higher LNG price at $12/GJ that caps the gas price from 2015.

3.6.4. Huntly Output

A key assumption made in our modelling is that all existing plants will continue to make their full capacity available over the duration of the modelling period. Preliminary modelling indicated that the Huntly generation station would have sustained high levels of production over the entire period of the analysis. These levels of production are considerably higher than those actually observed from Huntly over the past several years.

Huntly generation over the last eight years has averaged around 4,000 GWh corresponding to a 52% capacity factor. We have therefore constructed a sensitivity to study the implication for Huntly continuing at the 52% capacity factor in the long term. However, we recognise that there have been improvements on maintaining Huntly at a higher capacity factor going forward and as such, our base case assumption for maximum Huntly capacity factor is set at a higher level of 70%.

Figure 10: Annual generation from Huntly 1998-2005



Source: Transpower

3.6.5. Discount rates

Consistent with the GIT, we have considered two sensitivities around the base 7% discount rate. We have used both a lower 4% and higher 10% discount rate in test the sensitivity of results. Both least cost and Cournot bidding strategies are simulated at the higher and lower discount rates. A change in discount rate may imply change in timing and volume of generation investment and therefore discount rate changes needed re-optimising generation decisions.

3.6.6. Combination of low and high demand with a delay in transmission investment

Uncertainty in demand may imply transmission decisions have ‘option value’ because once built transmission will to some extent cater for any unexpected growth in demand before generation eventually catch up. The issue is more complex than merely focusing on growth in demand however, because transmission benefits are sensitive to *relative* growth in demand. For example, a lower overall growth over the NZEM may in fact mean more surplus economic transfer across the 400 KV and hence higher benefit to the transmission. Higher demand, on the other hand, may or may not mean additional benefit because the surplus generation that would have otherwise been transferred north may be soaked up by the higher demand in RNI and SI, or transmission may still add benefit by delaying investment in UNI. There is also a temporal dimension to the problem – higher or lower growth in demand may imply the transmission investment itself may be postponed or brought forward to deliver higher overall benefit.

In order to assess these impacts – we have constructed scenarios where the low and high demand scenarios are combined with a delay in the TP 400 KV option by two years. As discussed, lower demand will not necessarily lower benefit and higher demand will not necessarily increase benefits. The scenario does not yield 'option value' per se but provides an understanding of how the benefits change from the base case because of,

- Transmission being delayed, while
- Demand growth slowing down or increasing, and
- Generation decisions departing from the base scenario – however the rules of optimality still apply, i.e., they do not move randomly, but still conform to least cost principles.

4. MODELLING RESULTS AND SENSITIVITY ANALYSIS

4.1. SUMMARY OF RESULTS

CRA modelling analysis compares Transpower's original 400kV proposal and alternative 400 kV options to the EC 220 kV alternative with a 2017 in service date. We have analysed how the relative benefit varies across different generation development scenarios, demand conditions, and a range of other sensitivity parameters. In addition, we have considered a case in which the timing of transmission investment is varied. Finally, we have explored the impact on transmission benefits of alternative generation capacity plans, including the EC's proposed generation capacity plans for each development scenario, because any sub-optimality in generation capacity plan will have an impact on the benefits for transmission.

4.1.1. Base case least cost

The net (and gross) relative[21] benefits of the TP options compared to the EC option are expressed in discounted 2006-dollar terms. The term "gross" refers to total market benefit that comprises capital, fuel and USE savings to the system and once again relative benefit implies the benefits are over and above what EC 220 KV option achieves. The term "net" refers to gross benefits less the transmission capital cost also discounted to 2006.

Table 8: Net Market Benefit - EC 220 kV Option vs. TP Options ($millions discounted to 2006)

EC 20017 vs.	Least Cost
TP 400 1 Circuit @ 220 kV	-50.87
TP 400 2 Circuit @ 220 kV	-41.43
TP 400 kV in 2010	-67.46

While the EC transmission option is superior in NPV terms to all Transpower alternatives, the difference between various Transpower options and the EC option are all less than $70 million. The best Transpower option across all modelled scenarios has Transpower building two circuits at 400 kV but operating them initially at 220 kV.

21 Benefits are calculated as Transpower option market benefit less EC option market benefit, i.e, a positive number indicates Transpower option is superior to the EC option.

4.1.2. Impact of timing changes

We have also considered the impact of delaying the Transpower alternatives and of bringing forward the in service date for the EC option. Delaying the Transpower options to 2012 reduces the NPV difference between the EC and Transpower options by approximately $30 million, when assessed on a least cost basis averaged across all SOO generation development scenarios.

Table 9: Net Market Benefit - EC 220 kV Option vs. TP Options Delayed to 2012 ($millions discounted to 2006)

	EC 220 kV 2017	EC 220 kV 2015
TP 400 1 Circuit @ 220 Delayed 2012	-16.71	19.75
TP 400 2 Circuits @ 220 Delayed 2012	-9.44	27.02
TP 400 Delayed 2012	-36.04	0.42

In the event the in service date of the EC alternative is required to be brought forward – to 2015 from 2017, all Transpower options show a higher net market benefit than the EC alternative. The plausibility of having to move forward the timing of the EC option is linked to the probable need to decommission some of the existing transmission circuits in the Auckland region prior to constructing a new line. Given likely demand in the Auckland region, we understand this would require a new line to be in service by 2015 to maintain a N-G-1 security rating. In that event, the delayed Transpower options all show a higher net market benefit than the EC alternative, even when assessed on a least cost basis.

It may be observed that apparent advantages of the EC 220 kV option appear to be basically a product of its assumed timing, rather than any inherent advantage in the proposal itself. If, for whatever reason, the timing difference is reduced to three years, the 400 kV options appears to be superior, and that advantage may be expected to grow if the timing difference is further reduced.

4.1.3. Impact of generation development plan assumptions

We have also analysed a number of cases to test the impact of alternative generation capacity development plans, arising because of higher fuel price, higher hydro GWh generation, higher and lower demand paths and different discount factors. Key sensitivities are set out below. All assume a least cost analysis and are averages across all SOO generation development scenarios.

Table 10: Net Market Benefit (Sensitivities – EC 220 kV Option vs. TP Options ($millions discounted to 2006)

	Base	Higher Gas Price	Higher Hydro	High Demand	Low Demand	Discount Rate 4%	Discount Rate 10%
TP 400 1 Circuit Delayed 2012	-50.87	-56.02	-54.67	-95.88	-53.14	-35.73	-62.51
TP 400 2 Circuit Delayed 2012	-41.43	-37.95	-27.75	-53.78	-39.19	-7.23	-62.65
TP 400 Delayed 2012	-67.46	-55.78	-40.59	-64.53	-59.459	-13.5	-98.46

4.1.4. Components of Net Market Benefit Variation

Finally, we set out summary details of the components that make up the net benefits of each Transpower option relative to the EC option for a variety of sensitivity cases in Table 11 below. As noted earlier, the gross benefit comprises benefits arising from differences in: fuel costs between options, generation plant capital costs, and USE.

Table 11: Components of Net Market Benefit Least Cost Model - EC 220 kV Option vs. TP Options ($millions discounted to 2006)

		Base	SOO Generation	Higher Gas Price	Higher Hydro	High Demand	Low Demand	Discount Rate 4%	Discount Rate 10%
EC (2017) vs.	**Benefit**								
TP 400 1 Circuit @ 220	Fuel Cost	-9.56		-9.98	-40.62	-21.14	-55.66	-25.10	-5.49
	Plant Capex	2.04		-1.42	28.06	-19.84	40.61	12.84	0.43
	USE	-5.26		-6.52	-4.02	-16.81	0.00	-12.04	-2.37
	Gross Benefit	-12.78		-17.92	-16.58	-57.79	-15.05	-24.30	-7.43
	Tx Capex	-38.09		-38.09	-38.09	-38.09	-38.09	-11	-55
	Net Benefit	-50.87		-56.02	-54.67	-95.88	-53.14	-35.73	-62.51
TP 400 2 Circuit @ 220	Fuel Cost	11.84		15.50	38.40	1.20	3.59	18.78	6.68
	Plant Capex	-7.74		-7.86	-20.64	-4.66	2.55	-10.30	-4.77
	USE	-0.20		-0.25	-0.18	-4.98	0.00	-0.47	-0.09
	Gross Benefit	3.90		7.38	17.58	-8.44	6.14	8.01	1.82
	Tx Capex	-45		-45	-45	-45	-45	-15	-64
	Net Benefit	-41.43		-37.95	-27.75	-53.78	-39.19	-7.23	-62.65
TP 400 in 2010	Fuel Cost	23.89	31	38.45	74.58	18.12	33.42	39.02	17.90

		Base	SOO Generation	Higher Gas Price	Higher Hydro	High Demand	Low Demand	Discount Rate 4%	Discount Rate 10%
	Plant Capex	-6.28	0	-9.17	-30.10	0.89	-7.80	-7.85	-7.41
	USE	0.00	17	0.00	0.00	1.52	0.00	0.00	0.00
	Gross Benefit	17.61	47.89	29.28	44.48	20.53	25.61	31.17	10.49
	Tx Capex	-85	-85	-85	-85	-85	-85	-45	-109
	Net Benefit	-67.46	-37.18	-55.78	-40.59	-64.53	-59.45	-13.59	-98.46
TP 400 1 Circuit Delayed 2012	Fuel Cost	-11.19				-19.74	-56.51		
	Plant Capex	2.04				-19.84	42.13		
	USE	-5.26				-16.81	0.00		
	Gross Benefit	-14.41				-56.39	-14.38		
	Tx Capex	-2				-2	-2		
	Net Benefit	-16.71				-58.69	-16.68		
TP 400 2 Circuit Delayed 2012	Fuel Cost	7.12				2.37	1.50		
	Plant Capex	-7.74				-4.66	4.60		
	USE	-0.20				-4.98	0.00		
	Gross Benefit	-0.82				-7.27	6.10		
	Tx Capex	-9				-9	-9		
	Net Benefit	-9.44				-15.89	-2.52		
TP 400 Delayed 2012	Fuel Cost	15.33				18.57	30.17		
	Plant Capex	-6.28				0.89	-5.75		
	USE	-1.76				1.52	0.00		
	Gross Benefit	7.29				20.98	24.42		
	Tx Capex	-43				-43	-43		
	Net Benefit	-36.04				-22.35	-18.91		
EC (2015) vs.	**Benefit**								
TP 400 1 Circuit Delayed 2012	Fuel Cost	-12.32							
	Plant Capex	4.17							
	USE	-5.26							
	Gross Benefit	-13.42							
	Tx Capex	33							

		Base	SOO Generation	Higher Gas Price	Higher Hydro	High Demand	Low Demand	Discount Rate 4%	Discount Rate 10%
	Net Benefit	19.75							
TP 400 2 Circuit Delayed 2012	Fuel Cost	5.99							
	Plant Capex	-5.61							
	USE	-0.20							
	Gross Benefit	0.18							
	Tx Capex	27							
	Net Benefit	27.02							
TP 400 Delayed 2012	Fuel Cost	14.19							
	Plant Capex	-4.15							
	USE	-1.76							
	Gross Benefit	8.28							
	Tx Capex	-8							
	Net Benefit	0.42							

4.2. CONTEXT TO UNDERSTAND THE MODEL RESULTS

The New Zealand market is presently a hydro dominated system. Over time, the proportion of hydro will change as new generation capacity is required. These changes in mix will affect how the system operates. Future generation technologies, available locations for generation development and the timing of need for new generation are therefore key factors that drive the value of alternative future transmission configurations.

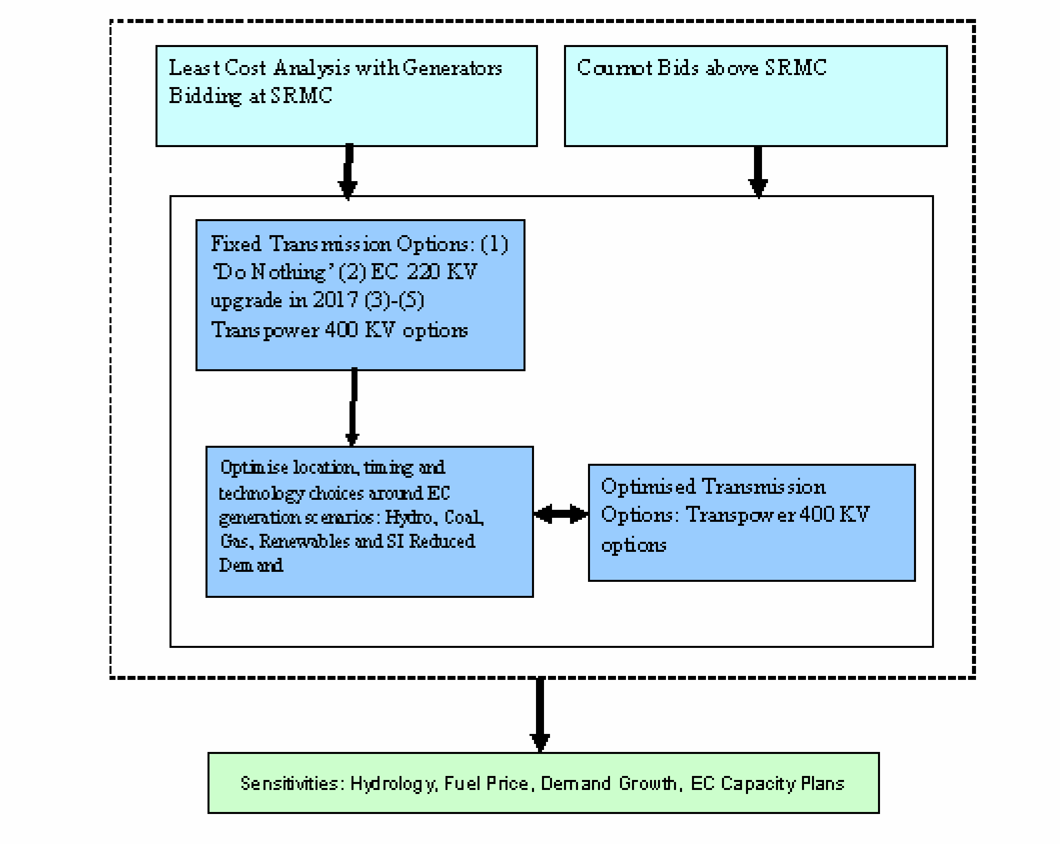
In addition, new transmission, generation, or demand response investment can affect competition outcomes and overall market efficiency, including the financial liquidity of contracting. Depending on circumstances of transmission constraints, ownership concentration within constrained regions and the scope for entry by generation and demand-response, transmission investments can have a different impact on “competition” than other types of system investments. If transmission investment improves the overall efficiency of the market, then this is a relevant benefit for consideration, particularly if the cost difference between a transmission and a non-transmission alternative is not otherwise material.

In order to fully appreciate the impact of the physical, cost and competition issues we have developed modes to assess:

- Different generation scenarios that significantly differ in generation technology and location relative to the transmission constraint and hence result in very different estimates of benefits;
- Alternative transmission choices including optimised transmission options that gradually add capacity over time
- The impact of least-cost outcomes based on SRMC offers as compared to outcomes reflecting strategic behaviour (Cournot-based offers); and
- Sensitivities around other physical and fuel price drivers as a cross-check on the robustness of the results.

Figure 11 sets out how cases have been constructed and analysed. Model results are presented in relative terms. We consider only those transmission options that render the system secure. In particular, we have expressed the benefits of the Transpower 400 KV options relative to EC 220 KV upgrade in 2017. All the benefit numbers that appear in the subsequent sections represent the discounted NPV of gross benefits in 2006 dollars of Transpower proposed options relative to EC 220 KV options – a positive number indicates that the particular Transpower option is superior to the EC option and vice versa.

Figure 11: Model cases and sensitivities



Transmission options are compared in terms of the following parameters:

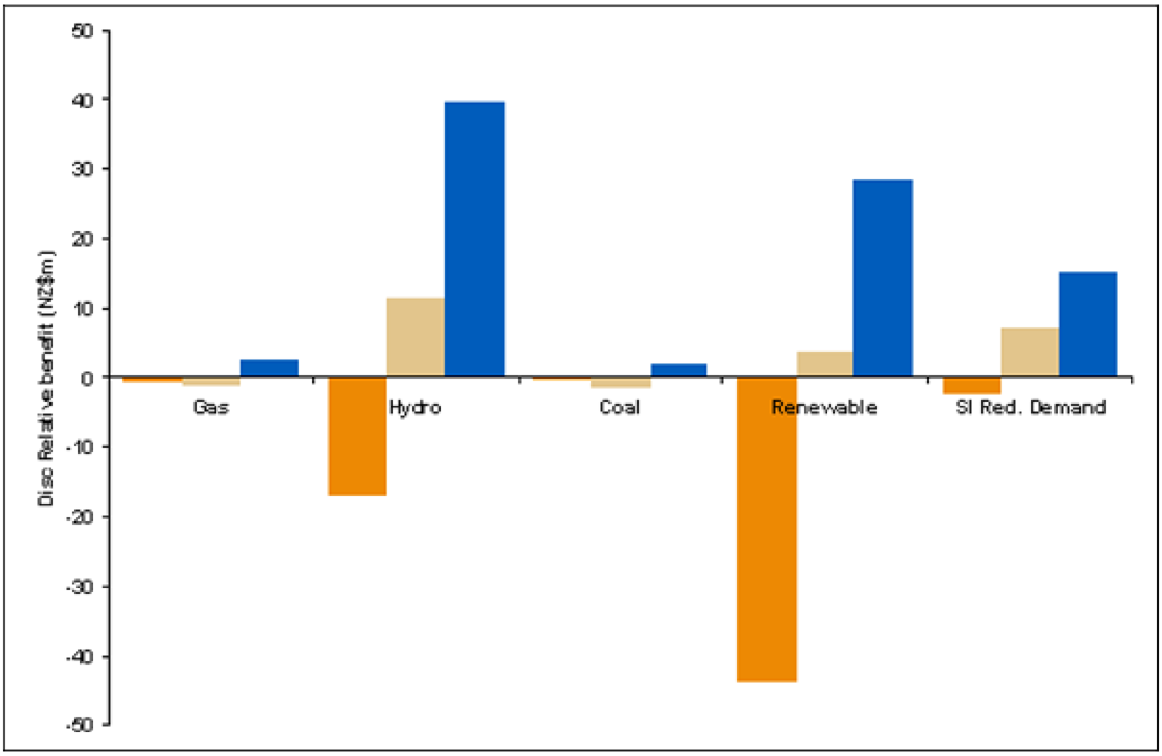
- **Reduction in total system cost** - which includes reduction in fuel costs, capital costs, and unserved energy costs and a break-up of these components is provided for each option. We note again that there is often a trade-off between the capital and fuel cost components of benefit. For example, if a transmission option delays building a baseload power station, there will be positive capital cost benefit; however, it is possible that more expensive generation will typically be incurred in the short run and therefore the fuel cost saving is negative.

- **System-wide transmission loss difference** – in our high level four node representation of the system, the system-wide losses comprise the HVDC losses and losses around the loop formed by HLY, RNI and UNI. This approximates the loss impact that will be realised in practice, as flows will change across the entire transmission system. We do not restrict the loss reduction to the specific transmission development that is being examined, because it is entirely possible that higher transmission capacity between the RNI and UNI will in fact incur higher overall system-wide losses due to impacts on transfers across the HVDC link. In addition, we reiterate that we have not translated the loss savings directly into dollar benefits. The economic impact of any loss saving is endogenously captured in the model through associated fuel cost savings and/or capacity cost reduction in the long term.

4.3. LEAST COST CASES

Figure 12 below shows a summary of the gross benefits from the least cost analysis over the various SOO scenarios. These benefits differ from net benefits presented earlier in that capital costs of the transmission projects themselves are ignored.

Figure 12: Least cost relative gross market benefits for Transpower 400 kV Options over the EC 220 kV Option



The original Transpower 400 kV option shows higher gross benefits across all generation scenarios although the magnitude of benefit is relatively small in scenarios that are dominated by thermal generation, e.g., Coal and Gas. This reduced benefit under thermal scenarios arises because the incremental capacity advantage does not bring any substantial economic transfer opportunity. This in part reflects our assumption of a uniform gas price throughout the country and our assumption that generic gas entry in UNI can cater for local demand. But, in other scenarios where there is substantial economic transfer opportunity, such as the Hydro/Renewable and to some extent the SI Reduced Demand scenario, benefits are quite significant at up to $40 million.

The gross benefit of the basic 400 kV in 2010 over the EC option averaged across all five-SOO generation scenarios stands at $17.6 million. The 400 kV single and double circuit options have average gross benefits of -$12.8 million and $3.9 million respectively.

Our least cost scenarios have an implicit assumption of perfect foresight, which results in a precise and highly tailored generation plan corresponding to the proposed transmission option. Sub-optimality in generation investment can result in increased transmission benefits as compared to an optimised generation plan – for instance, there may be more (sub-optimal) base load plants south of the constraint thus providing a higher fuel cost benefit. We have also constructed an “EC generation plan” which assumes that all (and only) the plants in the EC scenario are developed as per the EC schedule.

Under these assumptions, the relative average benefit of the original TP 400 kV proposal commissioned in 2010 increases to $48 million.

4.4. Cournot Analysis of Competition Benefits

The EC has previously suggested that Competition Benefits (CB) might legitimately be accounted for in the GIT. However, we also note that they have suggested that, in this case, they would be identical across all projects and would therefore have no influence on the final ranking. On the other hand, Castalia have estimated what they refer to as a "capacity benefit" for the Transpower proposal, of some $190m, and the EC has interpreted this to be a form of "real option value of excess transmission capacity", but estimated that it cannot be worth more than $5m.

We do not comment here on the validity of either analysis, but note that the arguments employed by both parties relate, at least in part, to judgements about the way in which Huntly, in particular, might respond to the situation it finds itself in with, and without, the transmission upgrade. But any such assessment should, at least in principle, attempt to assess realistic market behaviour, and must therefore involve some potential CB component, although it is not clear that either the Castalia or the EC analysis has assessed the CB component and its implications correctly in this case.

We have used a Cournot model to address this issue. Using a Cournot model to simulate market based generation offer strategies, we conclude that the Transpower 400 kV options do provide a on average CB over the EC transmission option. At the same time however, we note that as shown in Table 12 the value of benefits attributable to improvements in competition vary considerably across the SOO scenarios. In general, the hydro, renewables and reduced South Island demand scenarios exhibit positive and material competition benefits for the Transpower options, whereas the coal and gas scenarios show positive competition benefits for the EC option.

Table 12: Estimated Competition Benefits 2010 – 2040, EC 220 kV Option vs. TP Options ($millions discounted to 2006)

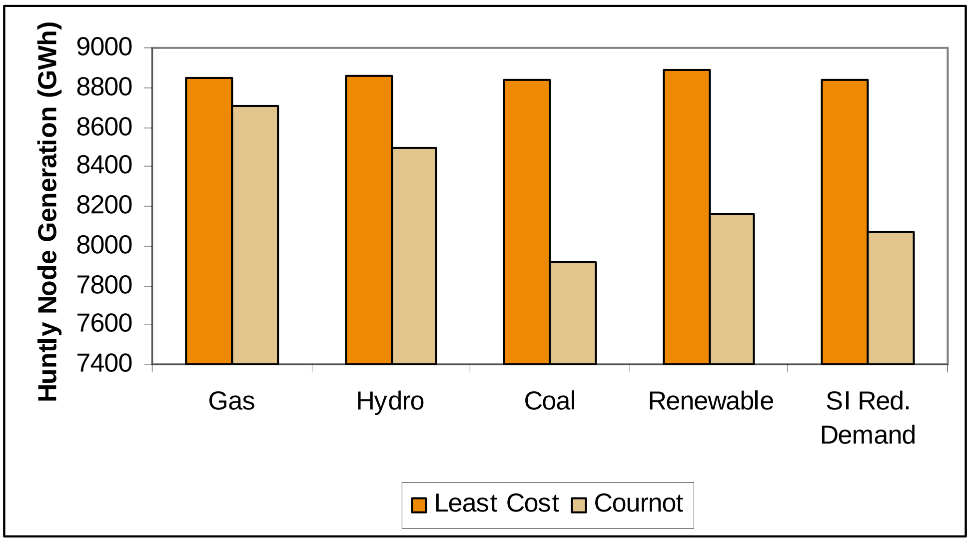
	Average Benefit
TP 400 1 Circuit @ 220 kV	-39.04
TP 400 2 Circuit @ 220 kV	3.61
TP 400 in 2010	3.01

The principal difference between the least cost and the Cournot cases is the possible change in generator bidding behaviour, with bids possibly significantly above generator SRMCs depending on the level of competition in the Cournot cases. T-CONE models the strategic interaction among the generators whereby, if transmission capacity is tight, generators in UNI can restrict output so as to force prices up, without fear that their market will be swamped by generation from generators on the other side of the constraint.[22]

Thus, conversely, increasing transmission capacity not only allows more generation from south of constraint to meet demand in UNI, but also forces generators in the UNI to respond to the prospect of such competition in their bidding strategy. The value of the first effect should be accounted for in a standard “least cost: assessment of net market benefit. But, the second implies a CB element which requires a more sophisticated analysis.

Generation at the Huntly node (existing Huntly units and new capacity additions) is another key to supply and prices in UNI. Figure 13 shows the average change in Huntly generation due to the change in bidding behaviour.

Figure 13: Average Annual Huntly Node Generation over 2006-2040 in Least Cost vs. Cournot

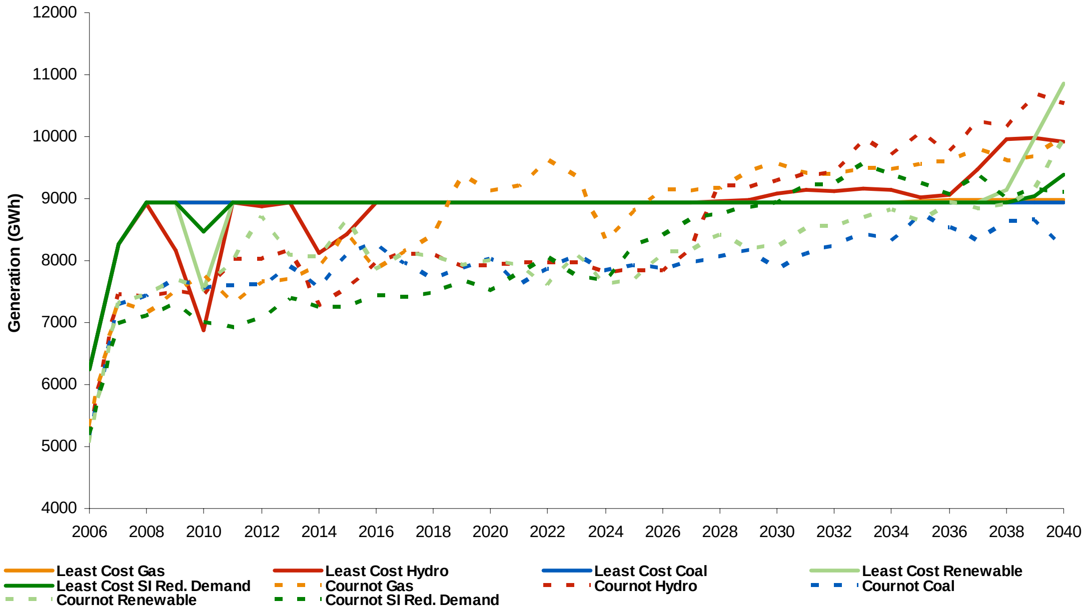


22 Importantly, this effect can arise even when, technically, there is enough transmission capacity to allow UNI demand to be met at a reasonable price, with some UNI plant operating on a least cost basis, and no physical restriction on flows. If the transmission capacity margin becomes tight enough, it can be optimal for participants on the downstream side of a line to withdraw enough capacity to force the line into constraint, thus creating a local market power situation, which they can then exploit by producing lower volumes, but at much higher prices. Thus the effective capacity of a line, in terms of disciplining competition may be significantly lower than its raw MW capacity.

In the Cournot bidding regime, average Huntly GWh drops depending on the generation scenario. A reduction in Huntly node generation has the impact of increasing prices in UNI but over the years it also attracts new entry and the generation can exceed that for the least cost generation case in later years.

Figure 13 shows the annual GWh for all years and all generation scenarios. The difference in generation during the early years is potentially significant

Figure 13: Huntly Generation for all years for Least Cost and Cournot bidding



4.5. Sensitivity Analysis

4.5.1. Hydrology, Demand Growth, Gas Price and Delaying TP 400 kV in 2010

We have looked at the following sensitivities for the least cost scenario:

1. Wet Scenario: 20% more hydro capacity available;
2. Low Demand: SOO low demand scenario;
3. High Demand: SOO high demand scenario;
4. High Gas Price: Long term gas prices assumed $12/GJ;
5. Reduced Huntly Generation: Huntly maximum capacity factor reduced to 52%;
6. Delayed Investment: 'TP 400 KV in 2010' delayed from 2010 to 2012;

7. Delay/Demand - Delayed investment of TP 400 KV option combined with high and low demand scenarios;

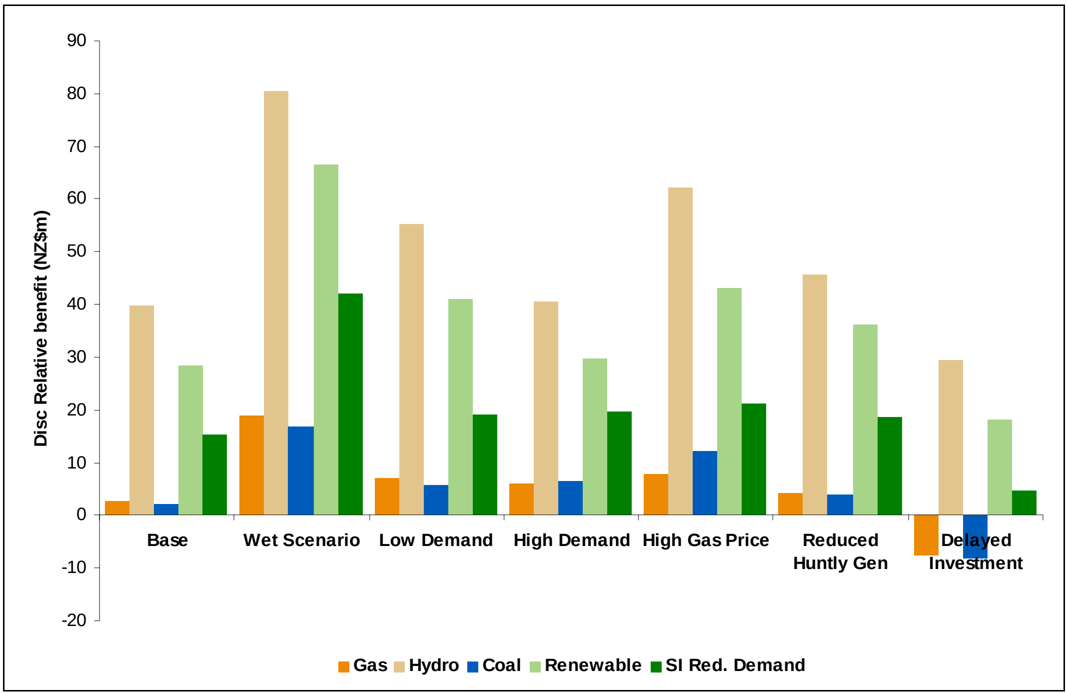
8. EC SOO generation: Generation capacity assumed to develop as per EC SOO assumptions, rather than optimised endogenously; and

9. Variation in discount rate: 4% and 10% as prescribed in the GIT.

4.5.2. Hydrology, Demand Growth, Gas Price and Delay

Figure 14 shows the variation of relative benefit from the TP 400 KV in 2010 proposal across the five of these sensitivity cases and for all generation scenarios. As we have discussed before – the variation of benefit is significant for the Wet case with the relative benefit reaching $80 million for Hydro generation scenario. The high gas price case (i.e., LNG price at $12/GJ) also implies a sizable impact on the benefit.

Figure 14: Relative market benefit of TP 400 kV in 2010 over EC 220 kV option for the sensitivity cases



4.5.3. Comparison of Benefits with Optimised Generation vs. EC Generation Capacity Plan

The benefit from a transmission upgrade is sensitive to the generation plan assumed. In our analysis thus far, we have considered the generation plan to be optimised from a portfolio of generators in the EC generation scenario and generic gas generation as may be needed to augment the EC scenarios especially after 2030. Any sub-optimality in generation investment could conceivably have an implication on the evaluation of transmission investment and it may affect benefit of transmission positively if there is less generation in the importing region relative to optimal capacity plan, or vice versa.

We have compared the optimised capacity plan with the EC capacity plan, i.e., we assume the generators come online as per EC schedule. Table 14 shows the increase in total system cost over 2006-2040 as a result of moving from an optimised generation capacity plan to the EC capacity plan for TP 400 kV in 2010 and EC 220 kV option. The sub-optimality in discounted NPV terms is between $916-1,367 million over the period 2006-2040. As the generation dispatch is optimised given the capacity plan, higher transmission capacity in TP 400 kV in 2010 option allows it to absorb some of the sub-optimality in generation investment.

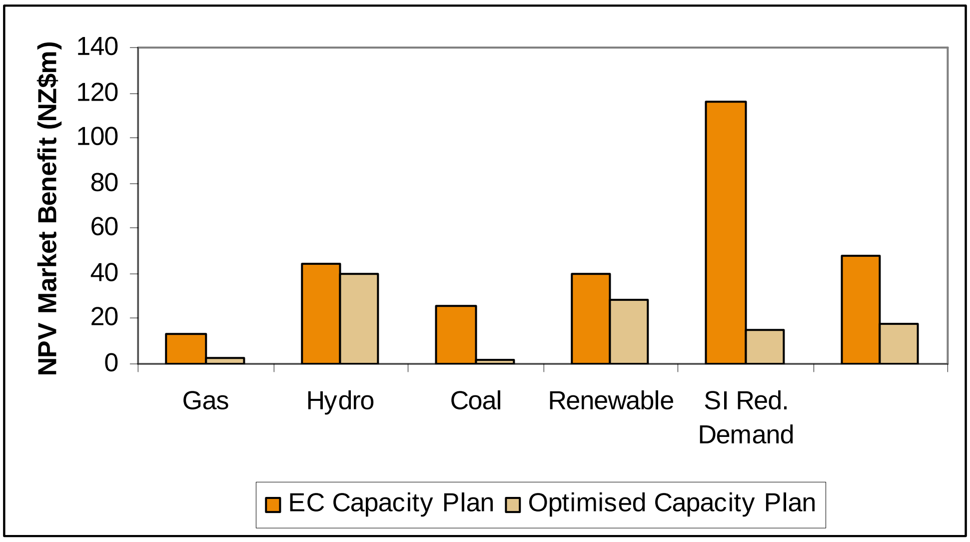
Table 14: Sub-Optimality of EC Capacity Plan (NZ$m)

		Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
EC 220 kV Option	Difference in total costs (Discounted NZ$ million in 2006)	927	1109	1037	1046	2715	1367
	% Sub-optimality	4.9	6.9	5.4	6.6	14.0	7.5
TP 400 kV in 2010	Difference in total costs (Discounted NZ$ million in 2006)	916	1105	1013	1035	2614	1336
	% Sub-optimality	4.8	6.9	5.3	6.5	13.5	7.4

Figure 15 shows that market benefits of TP 400 kV in 2010 relative to EC 220 kV option are higher under all generation scenarios using the EC capacity plan rather than the optimised capacity plan. This result arises because there is more generation south of the constraint that utilises the higher capacity in TP 400 kV in 2010.

This result is also significant in that it suggests that the generation optimisation approach utilised by CRA likely understates the market benefits of Transpower's transmission options. Consequently, our findings are likely to exhibit a conservative bias with respect to transmission investment, as a fully optimised generation plan (particularly one derived with perfect foresight, is not likely). For this reason, relatively modest relative benefits of non-transmission options arising when those options are compared to transmission options should be considered with particular care.

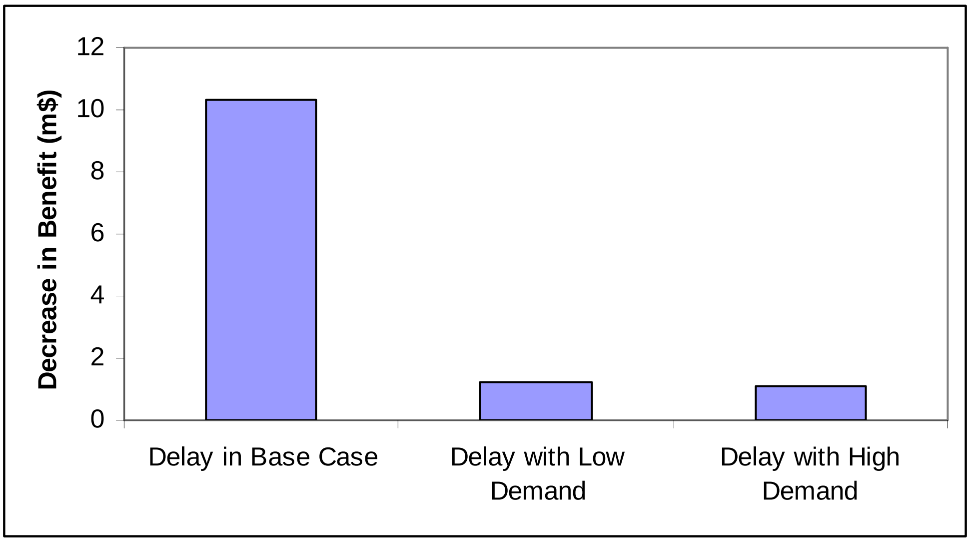
Figure 15: Market benefit of TP 400 kV in 2010 with EC capacity plan and optimised capacity plan



4.5.4. Delay in Investment combined with low and high demand scenarios

Most significant aspect of these scenarios is that the relative benefit of TP 400 KV option is robust – variation in demand growth rate either to a higher or a lower growth rate has a significantly lower impact on benefit suggesting that the option value of TP transmission is likely to be quite high. Figure 16 shows the *decrease* in benefit if 400 KV is delayed by two years in the base, low and high demand scenarios. The decrease in benefit is significantly lower for the two demand scenarios suggesting that the additional benefits that the TP option entails in the face of uncertain demand is quite robust – this is likely to reflect that the capacity and dispatch adjustments that are associated with low demand occur after 2012 and are reflective of an underlying high option value of TP transmission. Our analysis has not however delved into a probabilistic analysis of option value.

Figure 16: Decrease in gross benefit with 2-year delay in 'TP 400 KV in 2010'



4.5.5. Variation of discount rate

Applying a lower discount rate has the impact of generally increasing market benefit because the value of future capital deferral benefits and fuel cost savings are effectively weighted more highly than they would be given a higher discount rate. Transmission investment involve upfront costs but often quite long-lived benefits, thus the discount rate is an important factor. Use of a lower discount rate also affects generation investment and thus long-term dispatch. A lower discount rate tends to reduce the sensitivity associated with capacity optimisation, as the value of investment deferral is reduced at a lower discount rate. Conversely, the use of a higher discount rate has the opposite impacts.

The impact of discount rate on gross market benefit for the least cost scenario is substantial. A lower discount rate at 4% increases the benefit in the least cost scenario by $13 million. Discounting at a higher rate of 10% on the other hand reduces cost-based benefits by $7 million.

APPENDIX A: DETAILED RESULTS

A.1 LEAST COST SCENARIOS

Table15: Gross Market Benefits of investing in 'TP 400 KV 1 circuit @220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-0.64	-17.04	-0.32	-43.61	-2.28	-12.78
Fuel Cost Benefit NZ$m	-0.21	-23.11	11.61	-35.10	-0.99	-9.56
Capex Benefit NZ$m	-0.42	6.16	-11.94	12.03	4.38	2.04
Unserved Energy Benefit NZ$m	0.00	-0.09	0.00	-20.54	-5.66	-5.26
Total System-wide Losses (GWh)	274.01	-908.22	253.11	-925.36	257.30	-209.83

Table16: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-1.31	11.48	-1.45	3.56	7.23	3.90
Fuel Cost Benefit NZ$m	0.05	21.25	20.91	12.59	4.41	11.84
Capex Benefit NZ$m	-1.36	-9.77	-22.36	-8.17	2.98	-7.74
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	-0.86	-0.17	-0.20
Total System-wide Losses (GWh)	238.40	467.32	103.90	371.02	524.34	341.00

Table17: Gross Market Benefits of investing in 'TP 400 KV in 2010' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	2.60	39.82	2.09	28.35	15.18	17.61
Fuel Cost Benefit NZ$m	4.35	58.14	6.62	38.81	11.52	23.89
Capex Benefit NZ$m	-1.75	-18.32	-4.53	-10.46	3.66	-6.28
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	394.15	2017.71	-126.73	1753.65	948.65	997.49

A.2 SENSITIVITY CASES FOR LEAST COST

A.2.1 Wet Scenario

Assumed 20% more hydro is available in each scenario.

Table18: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	4.88	-21.85	5.76	-71.41	-0.29	-16.58
Fuel Cost Benefit NZ$m	1.76	29.23	10.70	-226.83	-17.98	-40.62
Capex Benefit NZ$m	3.13	-50.92	-4.95	174.88	18.16	28.06
Unserved Energy Benefit NZ$m	0.00	-0.16	0.00	-19.46	-0.47	-4.02
Total System-wide Losses (GWh)	410.26	-1324.53	132.02	-1080.71	57.10	-361.17

Table19: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	9.85	31.51	8.94	17.05	20.55	17.58
Fuel Cost Benefit NZ$m	2.94	128.95	13.75	24.73	21.65	38.40
Capex Benefit NZ$m	6.92	-97.45	-4.81	-6.84	-1.03	-20.64
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	-0.84	-0.08	-0.18
Total System-wide Losses (GWh)	506.35	597.75	209.32	721.67	847.12	576.45

Table20: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	18.70	79.67	16.78	65.57	41.67	44.48
Fuel Cost Benefit NZ$m	13.34	180.05	17.48	107.92	54.11	74.58
Capex Benefit NZ$m	5.37	-100.38	-0.70	-42.35	-12.43	-30.10
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	-0.01	0.00
Total System-wide Losses (GWh)	822.16	3057.84	470.22	3257.39	1657.39	1853.00

A.2.2 High Demand Scenario

SOO high demand scenario used.

Table21: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-3.96	-99.91	-12.23	-101.63	-71.20	-57.79
Fuel Cost Benefit NZ$m	1.04	-23.54	0.70	-59.82	-24.07	-21.14
Capex Benefit NZ$m	-0.31	-52.11	-3.85	-13.66	-29.25	-19.84
Unserved Energy Benefit NZ$m	-4.69	-24.26	-9.07	-28.15	-17.89	-16.81
Total System-wide Losses (GWh)	359.76	-362.32	344.25	-246.68	-165.81	-14.16

Table22: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	0.13	-10.93	-1.35	-15.95	-14.12	-8.44
Fuel Cost Benefit NZ$m	0.73	7.32	1.07	-1.62	-1.51	1.20
Capex Benefit NZ$m	-0.34	-10.47	-0.19	-6.76	-5.56	-4.66
Unserved Energy Benefit NZ$m	-0.26	-7.78	-2.23	-7.57	-7.04	-4.98
Total System-wide Losses (GWh)	365.54	493.14	404.81	392.57	326.72	396.56

Table23: Gross Market Benefits of investing in 'TP 400 KV in 2010' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	6.11	40.63	6.56	29.69	19.66	20.53
Fuel Cost Benefit NZ$m	6.01	46.88	5.25	21.01	11.44	18.12
Capex Benefit NZ$m	0.18	-9.09	1.54	6.21	5.61	0.89
Unserved Energy Benefit NZ$m	-0.07	2.84	-0.24	2.47	2.62	
Total System-wide Losses (GWh)	600.92	1710.12	688.18	1501.27	1078.61	1115.82

A.2.3 Low Demand Scenario

SOO low demand scenario used.

Table24: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	1.71	-19.90	1.03	-54.22	-3.88	-15.05
Fuel Cost Benefit NZ$m	-2.61	-63.27	-0.57	-202.00	-9.86	-55.66
Capex Benefit NZ$m	4.32	43.37	1.60	147.78	5.98	40.61
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	298.40	-1108.62	309.11	-1103.16	-54.61	-331.78

Table25: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	1.95	16.85	0.99	3.99	6.93	6.14
Fuel Cost Benefit NZ$m	-2.29	23.14	-0.56	-6.35	4.02	3.59
Capex Benefit NZ$m	4.23	-6.29	1.55	10.34	2.90	2.55
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	299.50	588.25	303.56	517.78	515.66	444.95

Table26: Gross Market Benefits of investing in 'TP 400 KV in 2010' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	7.02	55.11	5.73	41.00	19.22	25.61
Fuel Cost Benefit NZ$m	2.25	78.64	3.31	50.83	32.04	33.42
Capex Benefit NZ$m	4.77	-23.53	2.41	-9.84	-12.82	-7.80
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	
Total System-wide Losses (GWh)	522.25	2724.11	481.12	2738.65	1015.86	1496.40

A.2.4 High Gas Price

Long term gas price increased to $12/GJ.

Table27: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220 over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	2.66	-33.96	-3.83	-55.18	0.69	-17.92
Fuel Cost Benefit NZ$m	2.04	-29.49	-3.42	-19.73	0.71	-9.98
Capex Benefit NZ$m	0.62	0.50	-0.41	-13.52	5.71	-1.42
Unserved Energy Benefit NZ$m	0.00	-4.97	0.00	-21.92	-5.73	-6.52
Total System-wide Losses (GWh)	287.72	-1221.35	1.90	-1222.61	279.51	-374.97

Table28: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	1.90	16.03	2.40	5.54	11.05	7.38
Fuel Cost Benefit NZ$m	1.28	15.03	2.85	15.39	42.94	15.50
Capex Benefit NZ$m	0.62	1.01	-0.45	-8.76	-31.73	-7.86
Unserved Energy Benefit NZ$m	0.00	-0.02	0.00	-1.09	-0.17	-0.25
Total System-wide Losses (GWh)	269.51	554.86	398.43	337.10	518.00	415.58

Table29: Gross Market Benefits of investing in 'TP 400 KV in 2010' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	7.86	62.07	12.20	43.13	21.15	29.28
Fuel Cost Benefit NZ$m	7.24	65.59	12.64	54.00	52.80	38.45
Capex Benefit NZ$m	0.62	-3.52	-0.44	-10.87	-31.64	-9.17
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	489.07	2499.79	916.87	1958.13	933.49	1359.47

A.2.5 Delayed Investment (TP 2012)

TP 400 kV project delayed from 2010 until 2012.

Table30: Gross Market Benefits of investing in TP 400 KV 1 circuit@220 in 2012 over EC 220 KV in 2017 (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-2.24	-18.72	-1.93	-45.24	-3.91	-14.41
Fuel Cost Benefit NZ$m	-1.82	-24.79	10.01	-36.73	-2.62	-11.19
Capex Benefit NZ$m	-0.42	6.16	-11.94	12.03	4.38	2.04
Unserved Energy Benefit NZ$m	0.00	-0.09	0.00	-20.54	-5.66	-5.26
Total System-wide Losses (GWh)	240.64	-946.66	219.71	-962.66	220.02	-245.79

Table31: Gross Market Benefits of investing in TP 400 KV 2 circuit@220 in 2012 over EC 220 KV in 2017 (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-6.00	6.68	-6.14	-1.13	2.51	-0.82
Fuel Cost Benefit NZ$m	-4.64	16.45	16.22	7.90	-0.30	7.12
Capex Benefit NZ$m	-1.36	-9.77	-22.36	-8.17	2.98	-7.74
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	-0.86	-0.17	-0.20
Total System-wide Losses (GWh)	143.07	358.28	8.57	263.96	417.13	238.21

Table32: Gross Market Benefits of investing in TP 400 KV in 2012 over ’EC 220 KV in 2017 (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-7.71	29.45	-8.22	18.07	4.85	7.29
Fuel Cost Benefit NZ$m	-4.20	49.53	-1.93	30.28	2.94	15.33
Capex Benefit NZ$m	-1.75	-18.32	-4.53	-10.46	3.66	-6.28
Unserved Energy Benefit NZ$m	-1.76	-1.76	-1.76	-1.76	-1.76	-1.76
Total System-wide Losses (GWh)	217.49	1823.07	-303.38	1559.80	754.76	810.35

A.2.6 Delayed Investment (EC 2015/TP 2012)

EC 220 kV project brought forward from 2017 to 2015.TP 400 kV project delayed from 2010 until 2012.

Table33: Gross Market Benefits of investing in TP 400 KV 1 circuit@220 in 2012 over EC 220 KV in 2015 (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	0.59	-21.98	0.77	-45.04	-1.43	-13.42
Fuel Cost Benefit NZ$m	1.02	-37.58	11.61	-36.53	-0.14	-12.32
Capex Benefit NZ$m	-0.42	15.70	-10.85	12.03	4.38	4.17
Unserved Energy Benefit NZ$m	0.00	-0.09	0.00	-20.54	-5.66	-5.26
Total System-wide Losses (GWh)	314.68	-1006.30	263.47	-957.96	287.90	-219.64

Table34: Gross Market Benefits of investing in TP 400 KV 2 circuit@220 in 2012 over EC 220 KV in 2015 (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-3.17	3.43	-3.45	-0.92	4.99	0.18
Fuel Cost Benefit NZ$m	-1.81	3.66	17.82	8.10	2.18	5.99
Capex Benefit NZ$m	-1.36	-0.24	-21.27	-8.17	2.98	-5.61
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	-0.86	-0.17	-0.20
Total System-wide Losses (GWh)	217.11	298.64	52.33	268.66	485.01	264.35

Table35: Gross Market Benefits of investing in TP 400 KV in 2012 over EC 220 KV in 2015 (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-4.88	26.20	-5.52	18.27	7.33	8.28[23]
Fuel Cost Benefit NZ$m	-1.36	36.75	-0.33	30.49	5.42	14.19
Capex Benefit NZ$m	-1.75	-8.79	-3.44	-10.46	3.66	-4.15
Unserved Energy Benefit NZ$m	-1.76	-1.76	-1.76	-1.76	-1.76	-1.76

23 The benefit is higher compared to the TP 400 KV delayed to2012 scenario despite bringing EC upgrade forward by two years in the present scenario. This is explained by the loop flow effects together with the generic constraints (discussed in Appendix B.3) – despite the higher capacity in 2015-2016, flows around the loop are limited by these constraints under the EC 2015 scenario causing the relative benefit of the Transpower option to be higher.

Total System-wide Losses (GWh)	291.53	1763.43	-259.62	1564.50		822.64	836.50

A.2.7 Delayed Investment (TP 2012) with High Demand

TP 400 kV project delayed from 2010 until 2012.

SOO high demand scenario used.

Table36: Gross Market Benefits of investing in ’TP 400 KV 1 circuit@220’ over ’EC 220 KV in 2015’ (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-2.12	-98.95	-10.39	-100.55	-69.94	-56.39
Fuel Cost Benefit NZ$m	2.88	-22.58	2.54	-58.74	-22.80	-19.74
Capex Benefit NZ$m	-0.31	-52.11	-3.85	-13.66	-29.25	-19.84
Unserved Energy Benefit NZ$m	-4.69	-24.26	-9.07	-28.15	-17.89	-16.81
Total System-wide Losses (GWh)	398.04	-341.31	382.53	-223.39	-139.86	15.20

Table37: Gross Market Benefits of investing in ’TP 400 KV 2 circuit@220’ over ’EC 220 KV in 2015’ (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	2.03	-10.66	0.55	-15.15	-13.09	-7.27
Fuel Cost Benefit NZ$m	2.62	7.59	2.97	-0.82	-0.49	2.37
Capex Benefit NZ$m	-0.34	-10.47	-0.19	-6.76	-5.56	-4.66
Unserved Energy Benefit NZ$m	-0.26	-7.78	-2.23	-7.57	-7.04	-4.98
Total System-wide Losses (GWh)	404.69	499.57	443.96	409.00	347.01	420.85

Table38: Gross Market Benefits of investing in ’TP 400 KV in 2012’ over ’EC 220 KV in 2015’ (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	7.37	40.04	7.82	29.75	19.92	20.98
Fuel Cost Benefit NZ$m	7.27	46.29	6.51	21.07	11.69	18.57
Capex Benefit NZ$m	0.18	-9.09	1.54	6.21	5.61	0.89
Unserved Energy Benefit NZ$m	-0.07	2.84	-0.24	2.47	2.62	1.52
Total System-wide Losses (GWh)	624.68	1695.62	711.93	1501.14	1080.22	1122.72

A.2.8 Delayed Investment (TP 2012) with Low Demand

TP 400 kV project delayed from 2010 until 2012.

SOO low demand scenario used.

Table39: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220' over 'EC 220 KV in 2015' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	2.62	-19.64	1.94	-53.64	-3.20	-14.38
Fuel Cost Benefit NZ$m	-1.70	-63.01	0.35	-209.00	-9.18	-56.51
Capex Benefit NZ$m	4.32	43.37	1.60	155.37	5.98	42.13
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	318.53	-1107.53	329.20	-1094.21	-38.62	-318.53

Table40: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2015' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	2.55	15.97	1.56	3.67	6.74	6.10
Fuel Cost Benefit NZ$m	-1.68	22.26	0.01	-16.93	3.83	1.50
Capex Benefit NZ$m	4.23	-6.29	1.55	20.60	2.90	4.60
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	311.67	559.44	315.00	503.69	511.01	440.16

Table41: Gross Market Benefits of investing in 'TP 400 KV in 2012' over 'EC 220 KV in 2015' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	6.91	52.61	5.58	39.24	17.75	24.42
Fuel Cost Benefit NZ$m	2.14	76.14	3.17	38.82	30.57	30.17
Capex Benefit NZ$m	4.77	-23.53	2.41	0.42	-12.82	-5.75
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	516.12	2655.31	474.00	2691.18	979.80	1463.28

A.2.9 Huntly Low Generation

Huntly capacity factor reduced from 70% to 52%.

Table42: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	0.47	-17.24	0.25	-47.29	-5.73	-13.91
Fuel Cost Benefit NZ$m	3.21	-19.14	1.32	-47.70	4.32	-11.60
Capex Benefit NZ$m	-2.74	2.05	-1.08	18.12	-4.38	2.39
Unserved Energy Benefit NZ$m	0.00	-0.15	0.00	-17.71	-5.67	-4.71
Total System-wide Losses (GWh)	284.79	-919.70	350.31	-840.07	-77.65	-240.47

Table43: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-0.04	14.21	-0.31	5.02	9.26	5.63
Fuel Cost Benefit NZ$m	3.17	18.04	0.85	4.72	7.32	6.82
Capex Benefit NZ$m	-3.21	-3.83	-1.16	1.56	2.11	-0.91
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	-1.26	-0.17	-0.29
Total System-wide Losses (GWh)	272.29	549.11	333.44	372.43	498.28	405.11

Table44: Gross Market Benefits of investing in 'TP 400 KV in 2010' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	4.24	45.81	3.87	36.10	18.73	21.75
Fuel Cost Benefit NZ$m	10.02	54.34	4.66	65.66	15.90	30.12
Capex Benefit NZ$m	-5.78	-8.53	-0.78	-29.56	2.83	-8.37
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	441.55	2240.90	544.87	1964.97	1035.31	1245.52

A.2.10 Discount rate lowered to 4%

Table45: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 4% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	2.48	-31.56	3.43	-89.12	-6.75	-24.30
Fuel Cost Benefit NZ$m	4.14	-48.46	10.50	-91.91	0.23	-25.10
Capex Benefit NZ$m	-1.66	17.12	-7.07	48.49	7.31	12.84
Unserved Energy Benefit NZ$m	0.00	-0.22	0.00	-45.70	-14.29	-12.04
Total System-wide Losses (GWh)	283.99	-908.01	299.40	-905.30	257.30	-194.52

Table46: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 4% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	1.32	16.92	1.54	5.87	14.39	8.01
Fuel Cost Benefit NZ$m	4.71	28.04	26.09	25.57	9.47	18.78
Capex Benefit NZ$m	-3.39	-11.13	-24.55	-17.79	5.37	-10.30
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	-1.91	-0.44	-0.47
Total System-wide Losses (GWh)	248.38	467.32	148.28	355.08	524.34	348.68

Table47: Gross Market Benefits of investing in 'TP 400 KV in 2010' over 'EC 220 KV in 2017' (Discounted @ 4% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	7.05	63.93	6.99	50.24	27.65	31.17
Fuel Cost Benefit NZ$m	11.31	91.88	-2.32	72.85	21.41	39.02
Capex Benefit NZ$m	-4.26	-27.95	9.31	-22.61	6.24	-7.85
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	404.13	2026.57	-99.68	1737.71	948.65	1003.48

A.2.11 Discount rate increased to 10%

Table48: Gross Market Benefits of investing in 'TP 400 KV 1 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 10% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-1.90	-9.68	-1.81	-22.65	-1.14	-7.43
Fuel Cost Benefit NZ$m	-1.65	-10.95	1.57	-15.06	-1.35	-5.49
Capex Benefit NZ$m	-0.25	1.32	-3.37	1.93	2.52	0.43
Unserved Energy Benefit NZ$m	0.00	-0.05	0.00	-9.52	-2.31	-2.37
Total System-wide Losses (GWh)	274.64	-908.58	294.58	-925.36	255.91	-201.76

Table49: Gross Market Benefits of investing in 'TP 400 KV 2 circuit@220' over 'EC 220 KV in 2017' (Discounted @ 10% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	-2.32	8.18	-2.52	2.16	3.60	1.82
Fuel Cost Benefit NZ$m	-1.56	16.21	7.15	9.67	1.93	6.68
Capex Benefit NZ$m	-0.76	-8.03	-9.67	-7.12	1.74	-4.77
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	-0.39	-0.07	-0.09
Total System-wide Losses (GWh)	238.40	467.32	145.83	371.02	524.34	349.38

Table50: Gross Market Benefits of investing in 'TP 400 KV in 2010' over 'EC 220 KV in 2017' (Discounted @ 10% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	0.51	26.29	-0.02	16.89	8.80	10.49
Fuel Cost Benefit NZ$m	1.45	38.41	2.52	40.55	6.57	17.90
Capex Benefit NZ$m	-0.94	-12.12	-2.54	-23.66	2.23	-7.41
Unserved Energy Benefit NZ$m	0.00	0.00	0.00	0.00	0.00	0.00
Total System-wide Losses (GWh)	394.15	2017.71	-69.73	1727.71	948.65	1003.70

A.2.12 EC Capacity Plan

Table51: Gross Market Benefits of investing in 'TP 400 KV in 2010' over 'EC 220 KV in 2017' (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	13	44	26	40	116	48
Fuel Cost Benefit NZ$m	13	45	26	40	32	31
Capex Benefit NZ$m	0	0	0	0	0	0
Unserved Energy Benefit NZ$m	0	0	0	0	85	17
Total System-wide Losses (GWh)	442	2303	1249	2101	1424	1504

A.2.13 "Do Nothing" or No Transmission Investment

No upgrades on transmission lines, extra demand must be meet by regional generation.

Two alternatives modelled

10. UNI gas is limited to 700 MW

11. UNI gas is unlimited

Table52: Gross Market Benefits of investing in 'TP 400 KV in 2010' over No Upgrade to Transmission (Discounted @ 7% to 2006)

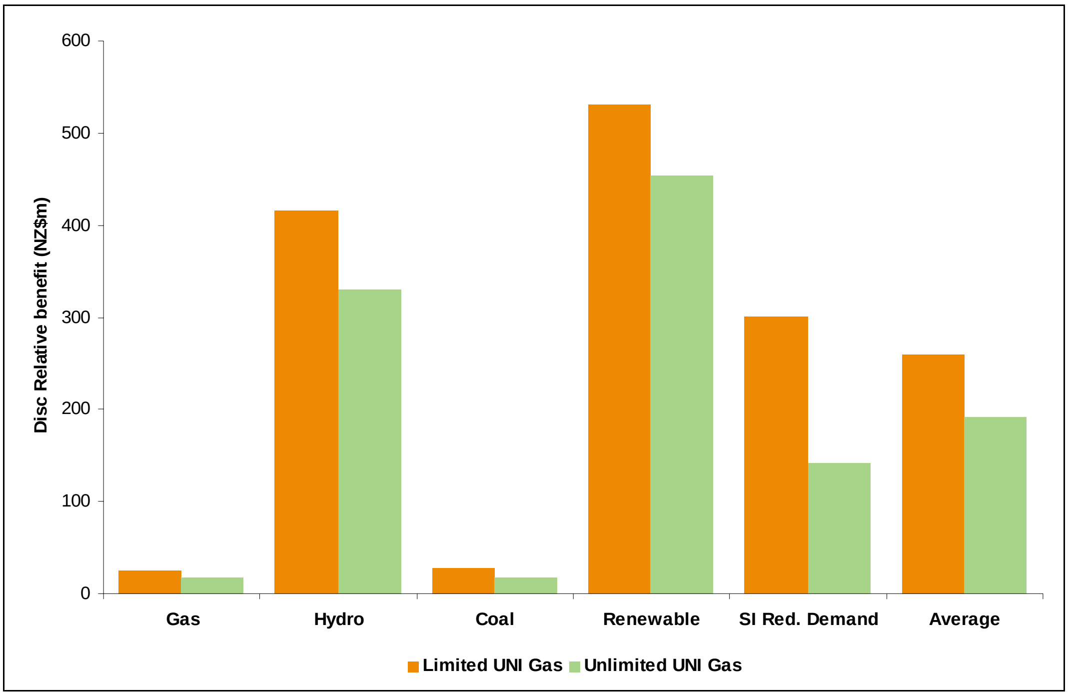


Table53: Gross Market Benefits of investing in 'TP 400 KV in 2010' over No Upgrade to Transmission with UNI gas limited to 700 MW (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	25.20	415.88	28.57	530.19	301.14	260.20
Fuel Cost Benefit NZ$m	21.31	616.63	14.66	554.09	172.37	275.81
Capex Benefit NZ$m	3.02	-269.85	13.31	-92.72	63.71	-56.51
Unserved Energy Benefit NZ$m	0.87	69.10	0.59	68.82	65.07	40.89
Total System-wide Losses (GWh)	1232.70	1011.95	1247.70	566.17	1783.63	1168.43

Table54: Gross Market Benefits of investing in 'TP 400 KV in 2010' over No Upgrade to Transmission with UNI gas unconstrained (Discounted @ 7% to 2006)

	Gas	Hydro	Coal	Renewable	SI Red. Demand	Average
Total Benefit NZ$m	17.64	329.79	17.66	454.63	141.33	192.21
Fuel Cost Benefit NZ$m	7.53	531.76	51.55	465.92	143.56	240.06
Capex Benefit NZ$m	10.10	-267.00	-33.88	-76.64	-57.76	-85.04
Unserved Energy Benefit NZ$m	0.00	65.03	0.00	65.34	55.53	37.18
Total System-wide Losses (GWh)	440.05	798.22	-121.39	641.78	621.01	475.93

APPENDIX B: INPUT DATA

B.1 FUEL COST DATA

	Oil	Gas	NI sub-bituminous	SI bituminous	SILignite	LNG
2005	16.034	5.372	4.000	2.500	2.000	7.863
2006	16.326	5.909	4.000	2.500	2.000	7.863
2007	16.617	6.500	4.000	2.500	2.000	7.863
2008	17.996	7.405	5.368	3.832	3.428	8.769
2009	18.288	7.529	5.368	3.832	3.428	8.769
2010	18.579	7.665	5.618	4.082	3.678	8.769
2011	18.579	7.815	5.618	4.082	3.678	8.769
2012	18.579	7.980	5.618	4.082	3.678	8.769
2013	18.579	8.161	5.618	4.082	3.678	8.769
2014	18.579	8.361	5.618	4.082	3.678	8.769
2015	18.579	8.655	5.618	4.082	3.678	8.769
2016	17.413	8.655	5.618	4.082	3.678	8.769
2017	16.247	8.655	5.618	4.082	3.678	8.769
2018	15.081	8.655	5.618	4.082	3.678	8.769
2019	13.915	8.655	5.618	4.082	3.678	8.769
2020	12.749	8.655	5.868	4.332	3.928	8.769
2021	12.749	8.655	5.868	4.332	3.928	8.769
2022	12.749	8.655	5.868	4.332	3.928	8.769
2023	12.749	8.655	5.868	4.332	3.928	8.769
2024	12.749	8.655	5.868	4.332	3.928	8.769
2025	12.749	8.655	5.868	4.332	3.928	8.769
2026	12.749	8.655	5.868	4.332	3.928	8.769
2027	12.749	8.655	5.868	4.332	3.928	8.769
2028	12.749	8.655	5.868	4.332	3.928	8.769
2029	12.749	8.655	5.868	4.332	3.928	8.769

2030	12.749	8.655	5.868	4.332	3.928	8.769
2031	12.749	8.655	5.868	4.332	3.928	8.769
2032	12.749	8.655	5.868	4.332	3.928	8.769
2033	12.749	8.655	5.868	4.332	3.928	8.769
2034	12.749	8.655	5.868	4.332	3.928	8.769
2035	12.749	8.655	5.868	4.332	3.928	8.769
2036	12.749	8.655	5.868	4.332	3.928	8.769
2037	12.749	8.655	5.868	4.332	3.928	8.769
2038	12.749	8.655	5.868	4.332	3.928	8.769
2039	12.749	8.655	5.868	4.332	3.928	8.769
2040	12.749	8.655	5.868	4.332	3.928	8.769

B.2 GENERATOR DATA

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	**Gas**	**Coal**	**Renewable**	**Hydro**	**SI Red. Demand**	**Annualised Capital Cost($/MW/year**
Existing Generators							
G_Aniwhenua		25	25	25	25	25	
G_Arapuni		192	192	192	192	192	
G_Aratiatia		90	90	90	90	90	
G_Atiamuri		84	84	84	84	84	
G_Aviemore		220	220	220	220	220	
G_Benmore		540	540	540	540	540	
G_Clyde		432	432	432	432	432	
G_Cobb		32	32	32	32	32	
G_Coleridge		53	53	53	53	53	
G_Glenbrook		112	112	112	112	112	
G_Highbank		25	25	25	25	25	
G_Huntly		1022	1022	1022	1022	1022	
G_Huntlye3P		0	0	0	0	0	

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	Gas	Coal	Renewable	Hydro	SI Red. Demand	Annualised Capital Cost($/MW/year
G_HuntlyP40		50	50	50	50	50	
G_Kaimai		34	34	34	34	34	
G_Kaitawa		37	37	37	37	37	
G_Kapuni		25	25	25	25	25	
G_Karapiro		96	96	96	96	96	
G_Kinleith		40	40	40	40	40	
G_KiwiDairy		69	69	69	69	69	
G_Manapouri		710	710	710	710	710	
G_ManapouriImprovements		0	0	0	0	0	
G_Mangahao		37	37	37	37	37	
G_MaraetaiA		176	176	176	176	176	
G_MaraetaiB		176	176	176	176	176	
G_Matahina		72	72	72	72	72	
G_Mokai		55	55	55	55	55	
G_NewPlymouth		300	300	300	300	300	
G_Ohaaki		62	62	62	62	62	
G_Ohakuri		112	112	112	112	112	
G_OhauA		264	264	264	264	264	
G_OhauB		212	212	212	212	212	
G_OhauC		212	212	212	212	212	
G_OtahuhuCC		365	365	365	365	365	
G_Patea		31	31	31	31	31	
G_Piripaua		44	44	44	44	44	
G_Poihipi		55	55	55	55	55	
G_Rangipo		120	120	120	120	120	
G_Rotokawa		24	24	24	24	24	
G_Roxburgh		320	320	320	320	320	
G_Southdown		122	122	122	122	122	

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	Gas	Coal	Renewable	Hydro	SI Red. Demand	Annualised Capital Cost($/MW/year
G_Tararua		68	68	68	68	68	
G_TCC		357	357	357	357	357	
G_TeApiti		90	90	90	90	90	
G_TeAwamutu		52	52	52	52	52	
G_TekapoA		25	25	25	25	25	
G_TekapoB		146	146	146	146	146	
G_TeRapa		42	42	42	42	42	
G_Tokaanu		240	240	240	240	240	
G_Tuai		60	60	60	60	60	
G_Waipapa		58	58	58	58	58	
G_Waipori		81	81	81	81	81	
G_Wairakei		157	157	157	157	157	
G_WairakeiExtension		0	0	0	0	0	
G_Waitaki		90	90	90	90	90	
G_Whakamaru		100	100	100	100	100	
G_Wheao		27	27	27	27	27	
G_Whirinaki		155	155	155	155	155	
SOO Generators							
G_MANHydro_GS	2004	25					278042
G_WDVWind_GS	2004	90					188786
G_MANHydro2_GS	2005	16					434441
G_WRKGeothermal_GS	2005	14					241759
G_HLYGas_GS	2007	365					94392
G_BRBGas_GS	2008	84					111897
G_ISLCoal_GS	2009	50					224030
G_MDNCoal_GS	2011	320					167700
G_WMGCoal_GS	2011	150					192440
G_TKRWind_GS	2012	120					169907

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	**Gas**	**Coal**	**Renewable**	**Hydro**	**SI Red. Demand**	**Annualised Capital Cost($/MW/year**
G_WRKGeothermal2_GS	2014	40					257876
G_CULHydro_GS	2015	36					348242
G_CMLHydro_GS	2015	45					275347
G_OTAGas_GS	2016	350					94392
G_DOBHydro_GS	2017	60					217380
G_CMLHydro2_GS	2019	30					217380
G_HLYGas2_GS	2019	400					89844
G_NPLGas_GS	2023	350					89844
G_DOBHydro2_GS	2023	35					305346
G_GLNGas_GS	2024	700					89844
G_BLNHydro_GS	2024	70					284695
G_MANHydro_CS	2004		25				278042
G_WDVWind_CS	2004		90				188786
G_MANHydro2_CS	2005		16				434441
G_WRKGeothermal_CS	2005		14				241759
G_HLYGas_CS	2007		365				94392
G_BRBGas_CS	2008		84				111897
G_WMGCoal_CS	2009		150				192440
G_MDNCoal_CS	2011		320				167700
G_NMACoal_CS	2012		380				169231
G_NPLCoal_CS	2014		400				156015
G_WRKGeothermal2_CS	2014		40				257876
G_MDNCoal2_CS	2017		400				156015
G_RDFCoal_CS	2018		150				179949
G_GISCoal_CS	2018		150				179949
G_NMACoal2_CS	2021		380				162623
G_WGNWind_CS	2021		100				144893
G_GISBiomass_CS	2022		30				310977

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	**Gas**	**Coal**	**Renewable**	**Hydro**	**SI Red. Demand**	**Annualised Capital Cost($/MW/year**
G_WILWind_CS	2023		100				139702
G_KAWBiomass_CS	2024		30				310977
G_MANHydro_RS	2004			25			278042
G_WDVWind_RS	2004			90			188786
G_MANHydro2_RS	2005			16			434441
G_WRKGeothermal_RS	2005			14			241759
G_SFDGas_RS	2006			15			80586
G_HLYGas_RS	2007			365			94392
G_WILWind_RS	2008			24			182178
G_ASBWind_RS	2009			50			179347
G_GISWind_RS	2009			75			179347
G_KAWGeothermal_RS	2010			150			219759
G_KAWGeothermal2_RS	2013			100			232089
G_OPKWind_RS	2013			150			167075
G_INVWind_RS	2013			180			167075
G_DOBHydro_RS	2013			210			258754
G_BLNHydro_RS	2014			70			284695
G_KTAWind_RS	2014			75			164244
G_GLNWind_RS	2014			80			164244
G_TMHWind_RS	2014			100			164244
G_WDVWind2_RS	2014			100			164244
G_WGNWind_RS	2014			100			164244
G_TRKGeothermal_RS	2015			40			338463
G_CULHydro_RS	2015			36			348242
G_TKRWind_RS	2016			120			158580
G_WRKGeothermal2_RS	2016			150			241759
G_WRKGeothermal3_RS	2016			180			241759
G_CULHydro2_RS	2017			70			232886

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	Gas	Coal	Renewable	Hydro	SI Red. Demand	Annualised Capital Cost($/MW/year
G_DOBHydro2_RS	2018			70			139230
G_WILWind2_RS	2018			100			152917
G_OPKWind2_RS	2018			50			152917
G_RDFHydro_RS	2019			134			429832
G_DOBHydro3_RS	2019			11			264841
G_MANHydro3_RS	2019			65			267522
G_MATHydro_RS	2019			25			624894
G_KTAWind2_RS	2019			150			150085
G_WPRHydro_RS	2020			50			289839
G_TKBHydro_RS	2020			44			179918
G_ATIGeothermal_RS	2021			50			322346
G_ROTGeothermal_RS	2021			40			338463
G_MTIGeothermal_RS	2021			40			338463
G_CMLHydro_RS	2021			45			275347
G_BLNWind_RS	2021			80			144893
G_WRKGeothermal4_RS	2022			100			275606
G_WRKGeothermal5_RS	2022			20			257876
G_LIVHydro_RS	2022			260			213684
G_CULHydro3_RS	2023			56			219988
G_KAWGeothermal3_RS	2024			50			261100
G_WRKGeothermal6_RS	2024			150			241759
G_WRKGeothermal7_RS	2024			50			333628
G_OKNHydro_RS	2024			60			304331
G_CULHydro4_RS	2024			60			281651
G_TUIHydro_RS	2024			75			265710
G_MANHydro_HS	2004				25		278042
G_WDVWind_HS	2004				90		188786
G_WRKGeothermal_HS	2005				14		434441

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	**Gas**	**Coal**	**Renewable**	**Hydro**	**SI Red. Demand**	**Annualised Capital Cost($/MW/year**
G_MANHydro2_HS	2005				16		241759
G_SFDGas_HS	2006				15		80586
G_HLYGas_HS	2007				365		94392
G_WILWind_HS	2008				24		182178
G_INVWind_HS	2008				180		179347
G_LIVHydro_HS	2009				260		213684
G_WDVWind2_HS	2009				100		179347
G_DOBHydro_HS	2012				60		217380
G_WRKGeothermal2_HS	2012				100		241759
G_WRKGeothermal3_HS	2012				180		241759
G_KAWGeothermal_HS	2013				100		232089
G_NPLCoal_HS	2014				300		163187
G_LIVHydro2_HS	2014				260		213684
G_TUIHydro_HS	2014				75		265710
G_MANHydro3_HS	2014				65		267522
G_BLNHydro_HS	2014				70		284695
G_KTAWind_HS	2014				150		164244
G_CMLHydro_HS	2015				90		263319
G_CULHydro_HS	2015				36		348242
G_CULHydro2_HS	2015				43		320635
G_TMHHydro_HS	2015				40		358314
G_CULHydro3_HS	2017				70		232886
G_WRKGeothermal4_HS	2018				100		241759
G_DOBHydro2_HS	2018				210		258754
G_RDFHydro_HS	2019				134		429832
G_MATHydro_HS	2019				25		624894
G_WPRHydro_HS	2020				50		322346
G_TKBHydro_HS	2020				44		179918

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	**Gas**	**Coal**	**Renewable**	**Hydro**	**SI Red. Demand**	**Annualised Capital Cost($/MW/year**
G_ATIGeothermal_HS	2021				50		322346
G_ROTGeothermal_HS	2021				40		338463
G_MTIGeothermal_HS	2021				40		338463
G_BLNWind_HS	2021				80		144893
G_WRKGeothermal5_HS	2022				20		257876
G_TKRWind_HS	2022				120		142533
G_GLNWind_HS	2022				80		142533
G_DOBHydro3_HS	2023				70		315635
G_WILWind2_HS	2023				100		139702
G_WGNWind_HS	2023				100		139702
G_KAWGeothermal2_HS	2024				50		261100
G_WRKGeothermal6_HS	2024				15		333628
G_OKNHydro_HS	2024				60		304331
G_DOBHydro4_HS	2024				11		264841
G_ISLWind_HS	2024				100		117656
G_TMHWind_HS	2024				200		137814
G_MANHydro_RDS	2004					25	278042
G_WDVWind_RDS	2004					90	188786
G_MANHydro2_RDS	2005					16	434441
G_WRKGeothermal_RDS	2005					14	241759
G_SFDGas_RDS	2006					15	94392
G_HLYGas_RDS	2007					365	94392
G_WILWind_RDS	2008					24	182178
G_WMGCoal_RDS	2009					150	192440
G_WDVWind2_RDS	2010					100	179347
G_WRKGeothermal2_RDS	2011					100	275606
G_WRKGeothermal3_RDS	2011					150	241759
G_INVWind_RDS	2013					90	167075

		Existing Capacity / Max New Capacity (MW)					
	Earliest Date	Gas	Coal	Renewable	Hydro	SI Red. Demand	Annualised Capital Cost($/MW/year
G_BLNHydro_RDS	2014					70	284695
G_GISWind_RDS	2014					75	164244
G_KTAWind_RDS	2014					75	164244
G_WGNWind_RDS	2014					100	164244
G_OTAGas_RDS	2014					400	94392
G_CULHydro_RDS	2015					36	348242
G_OPKWind_RDS	2018					150	152917
G_MATHydro_RDS	2019					25	624894
G_TKBHydro_RDS	2020					44	179918
G_CMLHydro_RDS	2021					45	275347
G_BLNWind_RDS	2021					80	144893
G_TMHHydro_RDS	2022					40	358314
G_TKRWind_RDS	2022					120	142533
G_GLNWind_RDS	2022					80	142533
G_KAWGeothermal_RDS	2023					100	232089
G_WILWind2_RDS	2023					100	139702
G_TRKGeothermal_RDS	2024					40	338463
G_OKNHydro_RDS	2024					60	304331
G_RDFHydro_RDS	2024					134	429832
Generic Plant							
G_OCGT_UNI	2010	0	205	233	233	100	94393
G_Diesel_UNI	2010	10000	10000	10000	10000	10000	94393
G_CCGT_UNI	2010	0	411	467	467	200	102973
G_OCGT_RNI	2010	10000	10000	10000	10000	10000	94393
G_OCGT_SI	2010	10000	10000	10000	10000	10000	94393
G_CCGT_RNI	2010	10000	10000	10000	10000	10000	102973

B.3 Generic Constraints

Winter			
Option	**group constraints equation (units in MW)**		**Description**
TP 400 kV D/C option	2010~2040	0.263*HLY-OTA +0.3458*0.0925*OTA-WKM <691-0.032*(1755-(HLY generation+0.5 * Stratford Generation))	protect HLY-OTA from overloading for a CA on OTA-WKM
EC 220 kV D/C option	2010-2016	0.5*OTA-WKM+0.179*0.5*HLY-WKM<257	protect OTA-WKM from overloading for a CA on HLY-WKM
EC 220 kV D/C option	2017~2040	0.261*HLY-OTA +0.146*0.331*OTA-WKM <691-0.032*(1755-(HLY Generation + 0.5 * Stratford generation))	protect HLY-OTA from overloading for a CA on OTA-WKM
Summer			
Option	**group constraints equation (units in MW)**		**Description**
TP 400 kV D/C option	2010~2040	0.263*HLY-OTA +0.3458*0.0925*OTA-WKM <633-0.032*(1755-(HLY generation+0.5 * Stratford Generation))	protect HLY-OTA from overloading for a CA on OTA-WKM
EC 220 kV D/C option	2010-2016	0.5*OTA-WKM+0.179*0.5*HLY-WKM<233	protect OTA-WKM from overloading for a CA on HLY-WKM
EC 220 kV D/C option	2017~2040	0.261*HLY-OTA +0.146*0.331*OTA-WKM <633-0.032*(1755-(HLY Generation + 0.5 * Stratford generation))	protect HLY-OTA from overloading for a CA on OTA-WKM