FINAL REPORT

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The Costs and Benefits of Regulating Transpower

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Date: 27 February 2006

CRA Project No. D08943-00

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1. INTRODUCTION AND EXECUTIVE SUMMARY

1.1. INTRODUCTION

On 22 December 2005 the Commerce Commission (Commission) published a notice of its intention to declare control in respect of electricity transmission services supplied by Transpower.[1] The Commission has set out its reasons for its preliminary conclusion in its document of 31 January 2006.[2]

As part of Transpower's response to the Commission's intention to declare control, CRA International has been retained to review the costs and benefits of introducing price control.

Our report is structured as follows:

- Section 2 provides an overview of the costs and benefits framework;
- Section 3 discusses, and where possible quantifies, the benefits of control; and
- Section 4 discusses, and where possible quantifies, the costs of control.

1.2. EXECUTIVE SUMMARY

The Commission has not specified a factual against which a counterfactual can be compared. Without this, it is not possible to carry out a rigorous cost benefit analysis of control of Transpower. In particular, the form of regulation under the factual matters, as it affects incentives and therefore efficiency.

The Commission finds that there would be net benefits from control of Transpower largely on the basis that Part F would not constrain Transpower's behaviour under the counterfactual (i.e., in the absence of control). As economists we are not in a position to opine on whether legally Transpower is subject to Part F under the counterfactual. However, as a practical matter it seems unlikely to us that Transpower would attempt to by-pass Part F, particularly because of the attendant risks to Transpower's regulatory asset base and therefore return.

Subject to these caveats, we have analysed the benefits of control as calculated by the Commission. We have both conceptual comments on these benefits, and comments on the actual calculations. These are summarised in Table 1.

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1 New Zealand Gazette (2005) "Commerce Act (Intention to Declare Control: Transpower New Zealand Limited) Notice 2005, Issue No.210, page 5382, 22 December 2005.

2 Commerce Commission (2006) *Regulation of Electricity Lines Businesses. Targeted Control Regime, Intention to Declare Control, Transpower New Zealand Ltd*, 31 January 2006.

Theoretical and empirical evidence suggests that price control is more likely to result in net costs associated with the timing of investment. Important amongst these are the potential costs of unserved energy if price control serves to delay investment. We have recalculated the NPV benefits from a 3 year deferral of the North Island 400kV upgrade as $55.6m-$68.4m. However, with plausible assumptions we also calculate the costs of unserved energy from a 3 year deferral as $8.4m to $87.9m. Given the relative costs and benefits, any delay in the 400kV project carries a significant risk that the costs of control may outweigh the benefits. Similar ratios of costs to benefits may also apply to other parts of the HVAC system, although we have not performed these calculations.

For the HVDC upgrade, a delay is unlikely to result in unserved energy, but is likely to raise spot prices and require investment in generation plant that would not be necessary with greater HVDC capacity. This effect could be quantified with a robust analysis of competition and other market benefits. However, given the time available to prepare our report, we have been unable to calculate the likely magnitude of such benefits for the HVDC.

There are potentially considerable "competition benefits" attached to investment in the transmission system, and a delay in investment would result in those benefits being foregone.[3] We have been unable to quantify these costs given the time available, but they are potentially important and should not be dismissed without further analysis.

Another implication of control is that Transpower's revenue requirement would increase if the Commission applied a building block revenue calculation and applied an appropriate weighted average cost of capital (WACC), reflecting a transfer of risk to Transpower from customers.[4] Given the Commission's past approach to WACC, we consider that a plausible value for the price control WACC is 9.2%. Over the control period, the NPV of the resulting revenue increase is $307.6m.

3 We use the term "competition benefits" in its broadest sense, as described in section 4 of this report. In other words, "competition benefits" refer to more than just the mitigation of market power.

4 Assuming that the price control would take the form of incentive regulation.

Table 1: Comparison of potential benefits of price control: Commission's assessment and CRA analysis ($m)

Benefit	Commission Estimate	Recalculated Estimate	Comment (assuming Part F not binding)	Comment (assuming Part F binding)
Investment efficiency gains - NPV of 5% reduction in investment costs - NPV of 10% reduction in investment costs	 $117m $234m	 $82m $164m	May be a legitimate benefit.	Any gains are a result of Part F not price control
Improved timing of investment - NPV of a 1 year deferral of planned NI Upgrade Project - NPV of a 1 year deferral of planned investment programme - NPV of a 3 year deferral of planned investment programme	 $31m $148m $405m	 Max $117m	Investment delay is more likely to result in net costs than net benefits	No benefits (by definition)
Total investment efficiency gains and improved timing of investments	$148m-$639m	Maximum $266m		
Lower cost implementation of investment	Significant, but unquantified		Unlikely to be significant. Benefits are unlikely to arise due to Transpower's existing commercial incentives.	No benefits (by definition)
More efficient time profile of prices	Significant, but unquantified		No evidence to support existence of benefits.	No evidence to support existence of benefits.
Limitation of excess profits in 2006/07	$36m		Commission has not determined these are excess profits. Likely to reflect timing issues. In a well defined factual scenario these excess profits may be strongly negative.	Commission has not determined these are excess profits. Likely to reflect timing issues. In a well defined factual scenario these excess profits may be strongly negative.

It is not clear, however, what approach the Commission intends to adopt in setting a factual revenue profile. Rather than employing a building block calculation, the Commission may instead simply look to eliminate the $36m of claimed "excess profits", and perhaps to seek other "efficiencies". The claimed excess profits are not, in fact, true excess profits: they are simply the amount by which revenues exceed the threshold price path. A true test of excess profits would analyse required revenues. We also calculate that a 10% revenue reduction would lead to $56.2m of additional debt costs, a 20% revenue reduction would lead to $96.7m of additional debt costs, and a 30% revenue reduction would lead to $166.3m of additional debt costs. Even a 10% reduction in revenue leads to additional debt costs that are higher than the $36m of claimed "excess profits".

The more general point here is that the Commission does not appear to have considered the implications of Transpower's self-imposed zero economic profit constraint through its EV adjustments. As well as its effect on profits, this constraint also affects risk allocation, which may well change under a Commission-imposed price control.

We therefore conclude that if the Commission is correct in assuming that Part F is not an effective constraint on Transpower, there is no evidence that there would be net benefits from introducing price control on Transpower. However, we consider that there are strong commercial reasons why Transpower would comply with Part F even in the absence of price control. Where Part F is a binding constraint there is no evidence to support the Commission's findings of benefits from price control, with the benefits instead being benefits from Part F itself.

In our view, it is difficult to think of a worse time to be imposing controls on Transpower than at a time when so many factors are in flux but are being (separately) resolved. The Electricity Commission processes are underway, significant investment uncertainties and proposals are being addressed and challenged appropriately by stakeholders, and very real and hard decisions must be made about New Zealand's electricity supply infrastructure. There is no doubt that retrospective improvements can be envisaged as they always can be, but the current situation does not appear to be a steady state in which observed or considered errors are the product of undesirable behaviours that merit corrective actions to prevent their repetition. In evaluating the benefits and costs of controls, significant regard must be had to the prospect that the "benefits" claimed are fleeting and not recurring while the costs imposed will be durable and long-lasting.

In summary, we do not believe the Commission's analysis provides a firm basis upon which to recommend price control. We believe the data is available for the Commission to undertake a comprehensive building blocks calculation of a factual revenue stream under price control and to evaluate costs of price control in greater detail. Furthermore, we think that the Commission's modelling should also account for uncertainty, e.g., by adopting a Monte Carlo simulation approach to assessing the benefits and costs of regulation.[5] Such an approach would enable the Commission to investigate directly how volatility might affect the probability that regulation might improve welfare.

5 Monte Carlo simulation involves constructing scenarios of potential future outcomes, based on a probability distribution of particular variables, e.g. demand, customer numbers, costs, etc.

2. COSTS AND BENEFITS FRAMEWORK

2.1. LACK OF SPECIFICATION OF FACTUAL AND COUNTERFACTUAL

In deciding whether or not to form an intention to declare control over the services provided by an electricity lines business, the Commission undertakes a cost benefit analysis. In particular, it evaluates whether "the forward looking long-term benefits of control to consumers would exceed the costs".[6] As part of this exercise it analyses the costs and benefits of the likely future outcome without price control (the counterfactual) and compares these to the likely future outcome with price control (the factual).

The Commission has not explicitly set out a factual scenario for Transpower, arguing that it should not pre-judge the future form of regulation at this stage of proceedings:[7]

> *Because there is a further consultative process under Part 5, the Commission considers that, in deciding whether or not to declare control, it should not pre-determine the form and nature of control. Therefore, post-breach inquiries under Part 4A are limited to assessing whether control* ***should*** *be imposed and do not involve determining* ***how*** *prices, revenue (and/or quality standards) might be authorised, following a declaration of control.*

The problem with this approach is that the form of regulation matters to behaviour and therefore efficiency. For example, different forms of regulation allocate risks between the firm and consumers in different ways, and therefore affect investment incentives in different ways.

The Commission also argues that it is not possible to develop a detailed factual because it is uncertain whether elements of Transpower's planned capital expenditure will be approved by the Electricity Commission. However, the type of building block analysis employed by the Commission in its analysis of Unison Networks Ltd is possible in the face of such uncertainty – all that is required is that different scenarios are used to reflect the impact of different approved levels of capital expenditure. In our view the uncertainty around future capital expenditure makes it all the more important to conduct a rigorous quantification of costs and benefits, as the Commission needs to be sure that its conclusions are robust given all likely outcomes.

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6 Commerce Commission 2006, p. 5.

7 Commerce Commission 2006, p.4.

In a building blocks approach there would be a need to apply a weighted average cost of capital (WACC). Appendix A to this report sets out potential WACC values that could be applied in a building blocks assessment of Transpower. These potential WACC values are derived exclusively from the Commission's past approach to WACC and do not reflect our own preferred approach.[8] We note that a plausible value for the price control WACC based on the Commission's approach is 9.2%, which is 1.9% higher than the WACC current applied by Transpower (7.3%). This means that introducing price control may result in considerable additional costs to consumers.[9]

However, it remains that the Commission has not defined a factual. Accordingly, it is not possible to undertake a rigorous cost benefit analysis without defining both the factual and the counterfactual.

2.2. The Regulatory Framework

The Commission's results rely heavily on its interpretation of the effect of the Part F processes and how these vary under the counterfactual and factual scenarios. In particular, the Commission assumes that Part F does not act as a constraint on Transpower's behaviour under the counterfactual.

How Transpower recovers the cost of investment approved under the Part F provisions depends on whether it is subject to the thresholds regime or price control. In either case the interaction of Part F with the Part 4A processes creates uncertainty and regulatory risk:

- Suppose Transpower is subject to the thresholds regime and a proposed Grid Upgrade Plan (or elements thereof) is approved by the Electricity Commission. Such approval does not imply that the price path threshold will be automatically adjusted given the Commission may view this investment as "business as usual" or "growth expenditure" covered by the pricing arrangements. Categorising various aspects of capital expenditure is at best subject to significant uncertainty; while

- The setting of a price or revenue cap under explicit price control may restrict the ability of Transpower to finance investments that pass the Grid Investment Test (GIT). This could occur if these investments were not foreseen at the time of developing the price cap or if there is no provision in the regulatory contract to adjust prices *ex post* for subsequent investment approval by the Electricity Commission.

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8 For an example of our own approach to cost of capital issues, see our report for Vector, and filed with the Commission, entitled "Response to the Commission's Draft Guidelines on the Cost of Capital", dated December 2005.

9 We estimate these costs as having a net present value of $307.6 million. These are considered in section 5.1.

The ability to recover investment costs varies depending on the pricing approach in place. However, we see no reason why the Part F provisions are not equally applicable under both regulatory models.

One of the Commission's hypotheses appears to be that by raising cash in advance, Transpower could simply make the grid investment and ignore the Electricity Commission. However, we do not think that this is a valid concern. For any major capital project the implication of bypassing the Electricity Commission would be severe for Transpower given that the investment would potentially not enter its regulatory asset base, nor would Transpower be able to earn its WACC on this investment through other means. The Commission's proposals indicate that ODV is the default valuation methodology, which will ensure that the assets are subject to optimisation and rigorous re-evaluation of replacement costs. Only if the investment has been subject to the GIT will the Commission consider allowing the asset into the regulatory asset base at Indexed Historic Cost.

The Commission also appears concerned that Transpower may preclude the ability of low cost transmission alternatives to develop due to its pre-approval investment distorting the Electricity Commission's assessment of any proposed transmission projects. The implied claim is that any pre-approval investment will be sunk and effectively excluded from the Electricity Commission's analysis. While this would be a theoretically correct application of cost-benefit analysis, we understand that Transpower, in applying the GIT, includes all costs of the proposed project, including any pre-incurred expenditure. Failing to include all costs in any proposal is likely to preclude Transpower from subsequently obtaining a full return on this asset, as the Electricity Commission cannot, by definition, approve costs that were not submitted for approval.

Nevertheless, for the purpose of analysis we assume that the Commission's view is valid and that Transpower is not constrained under Part F in any counterfactual scenario.

3. BENEFITS OF CONTROL

In respect of its quantification of the effects of control, the key benefits claimed by the Commission are "investment efficiency gains" ($117m to $234m) and "improved timing of investments" ($31m to $405m). Other benefits that are claimed to be "significant", but not quantified are "lower cost implementation of investments" and a "more efficient time profile of prices".

The Commission is correct to focus on the investment implications of regulation. As we have noted before, dynamic efficiency is the most important aspect of efficiency from the perspective of the long-term interests of consumers.[10]

In our view, the benefits claimed by the Commission are overstated. We discuss below specific issues with each of the claimed benefits, and the implications for the net benefits of control of Transpower.

3.1. "Investment Efficiency Gains"

The Commission's view is that investment outcomes will be more socially efficient when subject to the information exchange attendant to the GIT process, with particular value deriving from the consideration of non-transmission solutions.

Conceptually, this seems a fair point to us. Left to its own devices, it is likely that Transpower would favour a transmission solution, even if that was not the most socially efficient one.[11] The Commission's assumption that efficiency gains would be in the order of 5 to 10 percent seems arbitrary, and we are not aware of any empirical evidence that supports this figure. The Commission cites the Electricity Commission's December 2005 report,[12] but our reading of that report does not provide any evidence that savings of 5 to 10 percent are likely, with a number of the estimates in that report being high level estimates given with a confidence interval of ±20 percent.[13]

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10 See, e.g., our report for NGC, filed with the Commission, entitled "Response to Gas Control Inquiry Draft Framework Paper", dated 20 August 2003; and our report for Minter Ellison Rudd Watts, also filed with the Commission, entitled "Review of the Draft Determination on Raw Milk Transport Costs", dated 10 June 2005.

11 We note that because Transpower only earns its WACC on an investment, it will not have any particular preference among transmission solutions.

12 Commerce Commission 2006, para 234 (p. 64) and para 201 (p. 57).

13 See, for example, Electricity Commission, *Alternatives to Transpower's Proposed Whakamaru-Otahuhu 400kV Transmission Line: Alternatives Analysis Stage II*, December 2005, p. 42.

However, it is our understanding that Transpower is subject to the Part F processes under both the factual and the counterfactual. Even if these processes do deliver investment efficiency gains of the magnitude suggested by the Commission, these are properly benefits of the Part F processes. Therefore, there is no benefit from investment efficiency gains resulting from price control.

Nevertheless, for the sake of completeness we have reviewed the Commission's calculations, and we consider that they overstate the benefit that would be obtained if the Commission's view of the counterfactual is correct.

Applying its 5%-10% scaling factor, the Commission calculates that these benefits are in the order of $117m-$234m.[14] We are able to replicate these estimates, as shown in Table 2.

Table 2: Reproduction of Commission Calculation of Benefits from More Efficient Investment ($m)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	NPV
10% Efficiency Gains										
Original Capex	431.4	476.4	505.6	585.9	576.6	297.1	197.2	160.7	170.9	2,340.3
Revised Capex	388.3	428.8	455.0	527.3	518.9	267.4	177.5	144.6	153.8	2,106.3
Capex Savings	43.1	47.6	50.6	58.6	57.7	29.7	19.7	16.1	17.1	**234.0**
5% Efficiency Gains										
Original Capex	431.4	476.4	505.6	585.9	576.6	297.1	197.2	160.7	170.9	2,340.3
Revised Capex	409.8	452.6	480.3	556.6	547.8	282.2	187.3	152.7	162.4	2,223.3
"Savings"	21.6	23.8	25.3	29.3	28.8	14.9	9.9	8.0	8.5	**117.0**

Source: CRA calculations. Discount rate is 10%.

Even if the Commission is correct in claiming 5%-10% savings, the Commission's calculations overstate the potential benefits from more investment efficiencies. There are two main sources of overstatement:

- The revised capital expenditure figures include capital expenditure that does not fall under the jurisdiction of the Electricity Commission, and therefore will not be subject to the claimed 5%-10% savings; and
- The calculation includes capital expenditure over nine years, whereas we understand that control would only be imposed for a period of five years.

14 Commerce Commission 2006, p. 64.

We therefore consider that it is appropriate to make the following adjustments to the calculation of savings from more efficient investment:

- All “IT & Other” expenditure is not under Electricity Commission jurisdiction, so should be excluded from the calculation;
- “AC Substations”, “Transmission Lines”, and “Land” would largely be subject to Electricity Commission jurisdiction, so would be subject to the 5%-10% efficiency gains. Further, the efficiency gains should only be calculated for the five year price control period;
- We assume that all Electricity Commission decisions regarding the HVDC upgrade are made during the control period, and therefore all “HVDC” capital expenditure is subject to the 5%-10% efficiency gains, even though some of it is incurred after the end of the control period.

Before reflecting these adjustments in the calculation of savings, it is necessary to derive nominal estimates of Transpower’s capital expenditure forecasts. The aggregate forecasts shown in Table 2 are nominal forecasts, as is the final column in Table 4 of the Commission’s report.[15] However, Transpower advises that the capital expenditure components shown in the other columns of the Commission’s Table 4 are in real terms. We therefore inflate each of these categories of capital expenditure by 2% per year. The resulting nominal capital expenditure forecasts are shown in Table 2.[16]

Table 3: Nominal Capital Expenditure Forecasts ($m)

	AC Substations	Transmission Lines	HVDC	Land	Total excl IT & Other	Nominal Total	Implied IT & Other
2006/07	93.6	131.3	6.1	130.3	361.3	431.4	70.1
2007/08	99.2	183.9	30.4	101.0	414.5	476.4	61.9
2008/09	92.7	301.5	27.4	39.6	461.2	505.6	44.4
2009/10	54.1	380.0	106.6	1.9	542.6	585.9	43.3
2010/11	42.1	134.9	294.2	47.3	518.5	576.6	58.1
2011/12	44.6	47.2	103.0	51.0	245.8	297.1	51.3
2012/13	61.8	48.1	0.7	50.3	160.9	197.2	36.3

15 See Commerce Commission 2006, p. 63. Note that the final column of the table is headed “Total including IT, minor assets and inflation”. Inflation, as with the other items listed after the “including”, is not included in the other columns of the table.

16 Note that the effect of adjusting capital expenditure for inflation is to increase the capital expenditure estimates and hence increase the value of savings from more efficient investment, although this is this offset by using a nominal discount rate.

2013/14	41.4	90.8		1.6	133.8	160.7	26.9
2014/15	42.2	92.6		1.7	136.5	170.9	34.4
Total	571.7	1,410.3	568.4	424.7	2,975.1	3,401.8	426.7

Source: CRA calculations.

Making the aforementioned adjustments to the capital expenditure shown in Table 3 provides the capital expenditure savings shown in Table 4. On the basis of these revised capital expenditure savings we calculate net benefits from efficiency gains of $88.4m-$176.9m.

Table 4: Revised Calculation of Benefits from More Efficient Investment ($m)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	NPV
Capital Expenditure Subject to Efficiency Gains										
Substations	93.6	99.2	92.7	54.1	42.1					
Transmission	131.3	183.9	301.5	380.0	134.9					
Property	130.3	101.0	39.6	1.9	47.3					
Subtotal	355.2	384.1	433.8	436.0	224.3	-	-	-	-	
HVDC	6.1	30.4	27.4	106.6	294.2	103.0	0.7	-	-	
IT & Other	-	-	-	-	-	-	-	-	-	
Total	361.3	414.5	461.2	542.6	518.5	103.0	0.7	-	-	
10% Efficiency Gains										
Capex Savings	36.1	41.5	46.1	54.3	51.9	10.3	0.1	-	-	**176.9**
5% Efficiency Gains										
Capex Savings	18.1	20.7	23.1	27.1	25.9	5.2	0.0	-	-	**88.4**

Source: CRA calculations. Discount rate is 10%.

Even the values shown in Table 4 may overstate the capital expenditure that is subject to Electricity Commission decision. Given the current absence of precedent, it is unclear precisely what capital expenditure will or will not be subject to Electricity Commission jurisdiction. "Business as usual" expenditure might, for example, not require approval from the Electricity Commission. It is therefore reasonable to also calculate the benefits from more efficient investment assuming that routine replacement and refurbishment is excluded from the capital expenditure subject to the 5%-10% efficiency gains.

Transpower has advised that nominal replacement and refurbishment is as shown in Table 5. In Table 6 we have deducted the replacement and refurbishment expenditure from the capital expenditure subject to efficiency gains, and then recalculated the NPV of the savings. On the basis of these revised capital expenditure savings we calculate net benefits from efficiency gains of $82.1m-$164.2m.

Table 5: Nominal Replacement & Refurbishment Capital Expenditure

	2006/07	2007/08	2008/09	2009/10	2010/11
Substations	19.2	16.2	21.6	19.1	20.1
Transmission	7.6	11.1	20.4	17.9	16.2

Source: Transpower.

Table 6: Benefits from More Efficient Investment, Excluding Replacement & Refurbishment ($m)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	NPV
Capital Expenditure Subject to Efficiency Gains										
Substations	74.4	83.0	71.1	35.0	22.0					
Transmission	123.7	172.8	281.1	362.1	118.7					
Property	130.3	101.0	39.6	1.9	47.3					
Subtotal	328.4	356.8	391.8	399.0	188.0	-	-	-	-	
HVDC	6.1	30.4	27.4	106.6	294.2	103.0	0.7	-	-	
IT & Other	-	-	-	-	-	-	-	-	-	
Total	334.5	387.2	419.2	505.6	482.2	103.0	0.7	-	-	
10% Efficiency Gains										
Capex Savings	33.5	38.7	41.9	50.6	48.2	10.3	0.1	-	-	**164.2**
5% Efficiency Gains										
Capex Savings	16.7	19.4	21.0	25.3	24.1	5.2	0.0	-	-	**82.1**

Source: CRA calculations. Discount rate is 10%.

Allowing for the uncertainty in the level of savings and the extent to which capital expenditure would be subject to Electricity Commission jurisdiction, benefits from efficiency gains would be $82.1m-$176.9m, given the assumption that gains of 5%-10% would actually occur.

3.2. "IMPROVED TIMING OF INVESTMENTS"

The Commission assumes that under the counterfactual, Transpower will invest in the grid too early from a social perspective. However, the Commission does not justify this assumption, and it seems to us to be incorrect.

If Transpower is subject to the Part F process under the counterfactual, then the regime is common to the counterfactual and factual and there will be no efficiency gain by definition.

However, even if we instead assume that the Commission is correct that the Part F processes will not apply under the counterfactual then we do not believe the Commission's concern is valid.

Just as an unregulated monopolist will produce less than the socially efficient level of output, an unregulated monopolist will also invest *later* than is socially efficient, not earlier. As Guthrie (2005) states:[17]

> *In an intertemporal setting, the social planner would not invest as soon as the present value of the future flow of producer and consumer surplus equals the required investment expenditure since investment destroys valuable timing options. However, an unregulated monopolist waits even longer than this, since it bears the entire cost of the investment, but must share the resulting surplus with consumers. As in the static setting, here regulation can improve welfare if it can move investment towards the social optimum.*

Clearly investment timing options are important in the context of grid investments, as those investments are sunk and there is uncertainty about demand, construction costs and competing investment location.[18]

Transpower is obviously not an "unregulated" monopolist under the counterfactual, even if Part F does not apply. However, we do not think that there can be any argument that the regulatory and other governance constraints on Transpower under the counterfactual would provide incentives for Transpower to invest too early. We note that Transpower's Statement of Corporate Intent 2005/06[19] states, among other things, that:[20]

> *To achieve its principal objective, Transpower will:*

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17 Guthrie, Graeme (2005) "Regulating Infrastructure: The Impact on Risk and Investment", Journal of Economic Literature (forthcoming, June 2006), pp. 21-22.

18 For example, there is the risk that Transpower makes irreversible investments in transmission assets and then substantial generation investment occurs in the Auckland region that effectively strands Transpower's assets.

19 Transpower New Zealand Limited 2005, "Statement of Corporate Intent 2005/06".

20 We also note that the "Averch Johnson" effect relies on the unlikely situation of the regulated rate of return exceeding the true cost of capital.

a) be as profitable and efficient as comparable businesses:

• seek to be fully accountable for delivering and operating a national grid that meets the needs of users now and into the future;

…

• understand and deliver against customers' and consumers' needs with respect to the services Transpower provides;

• work with regulatory agencies to seek to ensure that risks to security of supply, as assessed by Transpower, are acknowledged and appropriately addressed in agreed investment plans;

• provide transmission services at the standard of quality and security agreed with National Grid users or required by regulatory agencies;

…

There may be an argument that these requirements result in Transpower placing more weight on consumer surplus than an unregulated monopolist would. However, even if that is correct, it is unlikely to result in Transpower bringing its investments further forward in time than a social planner would.

Accordingly, the Commission's concern about Transpower investing too early has no theoretical basis. Nor does it appear to have any empirical basis. The evidence that we are aware of suggests that the empirical issue is transmission *under*investment and delay. For example, Joskow (2005) states:[21]

21 Joskow, Paul L (2005) "Patterns of Transmission Investment", *Cambridge Working Papers in Economics,* Department of Applied Economics, University of Cambridge.

> *Implementing effective transmission investment policies has proven to be especially challenging as countries liberalize their electricity markets. In the U.S., transmission congestion has increased and barriers to needed transmission investment are perceived to be a growing problem … At the same time, investment in new transmission capacity has lagged the growth in electricity demand and the growth in new generating capacity (Hirst, 2004). In Europe, as wholesale power trading has grown, transmission congestion limits the geographic expanse of competition, limits opportunities fully to exploit generating capacity with the lowest operating costs, has led to concerns about generator market power within several countries (Newbery, 2004) and has created reliability challenges. As market liberalization proceeds, there has been very little investment in inter-TSO transmission capacity in Europe or the U.S. Intra-TSO congestion is a growing problem in some European countries as well (Serrani, 2004; Figures 2A, 2B, 2C). Policymakers in many countries with competitive power markets are increasingly concerned about reliability problems and reliability considerations are playing an increasingly important role at the interface of wholesale market design, transmission pricing, and transmission investment policies.*

In conclusion, we doubt that there would be any investment timing benefits arising from control of Transpower – rather, investment timing costs are a more likely outcome. Given that Transpower is likely to invest too late under the counterfactual, or at best at the socially optimal time, any deferral brought on by regulation under the factual would result in costs. The Commission's own argument is that the Part F process will slow investment down. The consultation procedures themselves will cause a delay. Furthermore, the Electricity Commission is not required to make a decision on a transmission investment proposal, particularly as it may consider that alternatives should be developed (which then may or may not actually develop).

We discuss the costs of control in section 4 of this report.

Even if the Commission's approach were correct, we have some comments on its calculations. The Commission calculates deferral benefits of up to $405m if all investments were deferred for 3 years.[22] Other deferral benefits claimed are $33.2m for deferring the HVDC upgrade by 1 year, and $31.4m for deferring the North Island 400kV upgrade by 1 year.

We are unable to replicate the Commission's calculations. As we show in Table 2, the NPV of planned capital expenditure is $2,340.3m. Deferring this for 3 years provides an NPV of $1,758.3m, using a discount rate of 10%.[23] This simple calculation indicates deferral benefits of $582.0m, which is greater than that claimed by the Commission. However, we consider that this simple calculation is incorrect.

22 Commerce Commission 2006, pp. 64-65.

23 1 year's deferral provides an NPV of $2,340.3m / 1.10 = $2,127.6m. 2 year's deferral provides an NPV of $2,127.6m / 1.10 = $1,934.1m. 3 year's deferral provides an NPV of $1,934.1m / 1.10 = $1,758.3m.

In order to accurately calculate the benefits of deferral, the following general adjustments should be made to the capital expenditure forecasts:

- Capital expenditure not subject to Electricity Commission jurisdiction should not be deferred;
- In general, deferral should only relate to capital expenditure incurred during the control period;
- Capital expenditure that is subject to Electricity Commission jurisdiction should reflect the assumption of 5%-10% efficiency gains, otherwise double counting will occur. However, capital expenditure that is deferred to outside the control period should not reflect any efficiency gains, as it is assumed that these gains only arise under control;
- It is unrealistic to defer 100% of capital expenditure on all projects that are subject to Electricity Commission approval. Many projects have, or will receive, approval, from the Electricity Commission, allowing them to proceed as planned. Further, Electricity Commission deferral of a project would not necessarily mean that there would be no transmission investment. For example, part of the current debate about the North Island 400kV upgrade is around whether the upgrade can be delayed by implementing other transmission investments prior to 2010; and
- Capital expenditure that is deferred should be inflated to reflect the fact that nominal costs increase over time.

The capital expenditure that is potentially subject to Electricity Commission jurisdiction is shown as the “capital expenditure subject to efficiency gains” in Table 4 and Table 6. All other capital expenditure would not be deferred so would provide no deferral benefit.

In Appendix B we calculate the benefit of a 1 year deferral of the HVDC upgrade and a 3 year deferral of the North Island 400kV upgrade. We calculate that the benefit of deferring the HVDC upgrade as $23.9m-$25.2m, somewhat less than the $31.2m claimed by the Commission. We also calculate the NPV benefit of deferring the 400kV upgrade by 3 years is $55.6m-$68.4m.

We now consider the benefits of a 3 year deferral on the entire capital expenditure programme that is potentially subject to Electricity Commission jurisdiction.

The Commission notes that of $158m of tactical transmission upgrade expenditure submitted to the Electricity Commission for approval, at the end of 2005 the Electricity Commission had yet to make a decision on $20m, and declined to approve $24.6m under the transitional provisions.[24] Transpower has also applied for Electricity Commission approval of some $129.90 million of interim grid expenditure (IGE) for a number of investments that are included in the Grid Upgrade Plan.[25] The Electricity Commission has made an indicative decision to approve $66.40 million of the IGE, it has requested further information on $49.20m, and has not approved $14.20m as IGE. We expect that over time, as Transpower obtains a more accurate understanding of the Electricity Commission's information requirements, the quantity of IGE requiring more information will diminish. Across the combined total of $288m TTU expenditure and the IGE expenditure, $180m (62.5%) has been approved. Further information has been requested, or a decision is pending, on $69m (24.0%), and $39m (13.5%) has been classed as economic investment that should be subject to an economic assessment as part of a Grid Upgrade Plan. Some 37.5% of expenditure submitted for approval has therefore not yet been approved. This is percentage is likely to reduce over time as (a) the Part F process becomes established and there is a regular cycle of production and approval of GUPs, and (b) Transpower understands more precisely the information required by the Electricity Commission.

For our analysis we assume that 25% of non-HVDC capital expenditure is deferred, but all of the HVDC capital expenditure is deferred. In total the deferral amounts to around 30% during the control period, and a considerably higher percentage during the later years of the HVDC upgrade. We also assume that the deferred capital expenditure is subject to an efficiency gain if it is incurred within the control period, but does not accrue the efficiency gain if it is incurred outside the control period. All deferred capital expenditure is subject to inflation at 2% per annum.

Table 7 summarises the benefits from deferral. Given our assumptions, the benefits from deferral by 3 years are $89.0m-$117.2m. However, the deferral benefit cannot just be added to the investment efficiency benefit. Table 7 also shows that there is a strong negative relationship between the benefit from investment efficiency and the deferral benefit: when the improved investment efficiency benefit is large, the deferral benefit is small; and when the improved investment efficiency benefit is small, the deferral benefit is large. The maximum total benefit, including both efficiency gains and deferral benefits is $205.7m-$265.9m if substantial portions (but not all) of Transpower's capital expenditure are deferred for 3 years.

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24 Commerce Commission 2006, para 53 (p. 6). We note that "declining to approve" is not the same as "not approving". The Electricity Commission's decision was essentially that it did not have jurisdiction to approve this amount under the transitional provisions, rather than it declining the investment per se.

25 Electricity Commission (2005c) *Assessment of Transpower's applications for interim grid expenditure dated 31 October 2005 and 16 December 2005 (Grid Development Proposals)*, Consultation Paper, 22 December 2005.

Table 7: Benefits from Deferral and Improved Investment Efficiency, All Capital Expenditure, 25% of Non-HVDC Delayed Three Years ($m)

	5% Efficiency Gain	10% Efficiency Gain
Improved Investment Efficiency	88.4	176.9
Deferral Benefits	117.2	89.0
Total	205.7	265.9

Source: CRA calculations. For detailed tables showing our calculations see Appendix B.

3.3. "Lower Cost Implementation of Investments"

The Commission argues that, "… regulatory oversight is likely to provide significant additional benefits from lower cost implementation of investments and a more efficient time profile of prices" (page 10).

The Commission has not set out the mechanisms that will result in lower cost implementation of investment. If Transpower were subject to the same Part F provisions relating to investment under the counterfactual and factual scenarios, no benefits could arise. If Part F were not to apply under the counterfactual (as assumed by the Commission), there are a range of alternative mechanisms that provide cost and efficiency incentives for Transpower:

- As an SOE, Transpower is required to be as "profitable and efficient as comparable businesses that are not owned by the Crown" (section 4(1)(a) of the State-Owned Enterprises Act);
- Transpower's Statement of Corporate Intent (SCI) identifies various financial and operating performance targets; and
- Even absent price control, the Commerce Commission's asset valuation proposals provide a strong incentive to ensure efficient investment. The Commission's proposals indicate that ODV is the default valuation methodology, which will ensure that the assets are subject to optimisation and rigorous re-evaluation of replacement costs. Only if the investment has been subject to the GIT will the Commission consider allowing the asset into the regulatory asset base at Indexed Historic Cost. This suggests that Transpower retains strong incentives to invest efficiently if it is to earn a commercial return on its investment, even if it uses the building block model for revenue setting.

Furthermore, any regulator (whether it is the Commission or the Electricity Commission) is likely to be at a severe informational disadvantage compared to Transpower, making it difficult to judge investment efficiency.

Accordingly, we query how material this category of claimed benefit is.

3.4. "MORE EFFICIENT TIME PROFILE OF PRICES"

The Commission's fundamental concern appears to be that Transpower is pre-funding its investment requirements. As well as the Commission believing that this will result in inefficient investment, the Commission also argues that the resulting time profile of prices is inefficient. We consider each of these issues below.

In respect of the issue that pre-funding may result in inefficient investment, we surmise that the Commission is particularly concerned about the potential for expenditure already incurred to distort the Electricity Commission's assessment of any proposed transmission projects. As discussed earlier in this report, it is our understanding that the Electricity Commission includes all costs in its analysis, and Transpower has strong incentives to include all costs in its application. Therefore, to the extent that pre-funding allows Transpower to invest before obtaining approval, this does not alter the Electricity Commission's decision.

A further dynamic efficiency issue arises in respect of the time profile of prices. There are a potentially infinite number of time profiles that have the same NPV, but the various profiles are not equivalent in terms of the incentives that they would provide to Transpower to invest. The Commission appears to be concerned that Transpower has based its revenue requirement on forecasts of capital expenditure that have not yet been approved by the Electricity Commission. The alternative would be for Transpower to assume that no expenditure would be approved by the Electricity Commission, and include no unapproved expenditure in its forecasts. Where the Electricity Commission approved expenditure during the course of a year, Transpower would then be in the position of having received less revenue than it "should" have done under a zero economic profit framework. Given Transpower's EV adjustment mechanism this is not necessarily a problem, as the deficit – relating to expenditure approved by the Electricity Commission – would then be recovered with interest from future customers. Transpower would then be in the position of levying EV debits on its customers rather than providing credits to return any over-recoveries. On an NPV basis Transpower would be completely neutral between these two options. Whether the two profiles are NPV neutral for consumers depends on their discount rate, and this will vary across consumers.

That the two options are NPV neutral casts strong doubt on there being any benefit from a more efficient time profile of prices. First, we note that it is likely that the Electricity Commission will approve more investment than it will decline.[26] If that is true, then a

26 We consider that it is reasonable to assume that the Electricity Commission will approve more capital expenditure than it will decline, particularly over the medium to long term. First, it is reasonable to assume that Transpower is applying a version of the GIT when it puts forward its proposed investments. Although Transpower's initial interpretation of the GIT may not be precisely the same as the Electricity Commission's interpretation of the GIT, it is reasonable to assume that the two interpretations will be harmonised over the course of the first few applications. The major difference between the GIT as applied by Transpower and the GIT as applied by the Electricity Commission will then rest on the superior information that Transpower has about appropriate transmission solutions, and the superior information that the Electricity Commission has about non-transmission solutions (assuming that third parties are more willing to share commercially sensitive information with the Electricity Commission).

revenue requirement based on a reasonable forecast of capital and operating expenditure forecasts is likely to be a closer approximation to actual costs than if the forecasts excluded yet-to-be approved expenditure, and thus the prices will be a closer approximation to efficient prices. This also means that EV adjustments are likely to be smaller when Transpower's revenue requirement is based on a reasonable forecast of capital and operating expenditure than when expenditure that the Electricity Commission is likely to approve is omitted from the forecast. It is therefore far from clear that requiring Transpower to under-recover and charge EV debits is more efficient than allowing Transpower to generally recover, and then returning any over-recoveries via EV credits.

That the two options are NPV neutral also provides no indication of which option will provide better investment outcomes. Assuming Electricity Commission approval and then providing a rebate (credit) in the event that approval is not granted provides a better cash position for Transpower to undertake the approved investments. Given the very large cyclical upswing in Transpower's capital expenditure, it is possible that this could be the difference between some necessary investments proceeding or being deferred indefinitely.

On balance,and considering the probability that the Electricity Commission will approve more investment than it will decline, it is a reasonable approach for Transpower to included budgeted, but not yet approved, expenditure in its revenue requirement calculation.

In respect of the issue that the time profile of prices may be inefficient, it is not clear to us what the Commission's precise concern is in this regard. We assume it is that consumers today are paying for an investment that they are not yet enjoying the benefits of. If so, then we note that this is a common issue in respect of infrastructure investment, and indeed any investment. Consider, for example, the investment by a consumer in a motor vehicle, required at time *t*. Somehow the consumer needs to fund this investment. She could "save up" for the car, i.e., pre-fund it, or alternatively she could borrow to purchase it and pay the interest costs in her repayments. In practice it is likely that we would observe both types of behaviour.

It is not clear why the situation should be any different when an agent is interposed. A firm such as Transpower is simply an agent that is tasked with providing transmission services for the benefit of consumers.

In respect of infrastructure investment more specifically, consider road funding in New Zealand. Road users (via road user charges, fuel excise tax, motor vehicle registration and licensing fees) contribute to a fund (the National Land Transport Fund), from which road investments are financed.[27] This appears to be a very similar process to the one that the Commission has concerns about in respect of Transpower.

27 Some financing comes from other sources as well, such as local rates.

Similarly, the following statement is taken from the 2005 annual report of Auckland International Airport Limited (CEO's Operational Review):

> *Another consultation process has been undertaken about the airport development charge. A significant outcome has been the airlines' agreement that AIAL retain the current $25.00 departure charge after the Government $5.00 charge for aviation security and the Civil Aviation Authority services transfers to the airlines from 1 October 2005. The $5.00 is currently collected by the airport company in the departure fee. This agreement recognises the need to fund additional terminal facilities to handle the ever-increasing demand for facilities and services at Auckland Airport*

Furthermore, retained earnings are a source of investment for firms in competitive markets.

Finally, when determining a price path via the building blocks method, regulators typically allow the regulated business some pre-funding or incentives to earn higher returns on capital expenditure through a range of mechanisms. These include: developing a revenue requirement based on an assumed profile of capital expenditure that need not match actual expenditure;[28] and smoothing the revenue received over the regulatory period to minimise price shock.[29]

3.5. EXCESS PROFITS

As far as we can determine, the Commission *assumes* that revenue in excess of that permitted by the threshold price path is "excess profits" (see, for example, page 63 of the Commission's paper). However, without doing an analysis of Transpower's revenue requirements, it is not appropriate to simply equate revenue in excess of that permitted by the threshold price path to be "excess profits", given that the thresholds were never set in the context of such an analysis. Indeed, the Commission's own historic practice when analysing the existence of "excess profits" has been to carry out a revenue requirement exercise (e.g., in respect of airports, gas pipelines, and Unison).

28 For example, in Australia the regulator of electricity transmission services (now the Australian Energy Regulator) develops an ex-ante allowance for capital expenditure. The Statement of Regulatory Principles [Australian Competition & Consumer Commission 2004 "Statement of Principles for the Regulation of Electricity Transmission Revenues"] states that this ex-ante allowance reflects "a probabilistic assessment of expected investments during the regulatory period" (p. 11). It goes on to state: "However, the allowance does not entail project-specific approval and although an expected project may have been included in the determination of the allowance, this does not oblige the TNSP to develop that project during the regulatory period." (ibid). A similar approach to capital expenditure is applied by many regulators of distribution activities, including the Victorian Essential Services Commission (ESC) and the Essential Services Commission of South Australia (ESCOSA).

29 In its decisions to date the Australian Competition and Consumer Commission has developed an X-factor with the aim of providing a smoothed revenue path with the similar net present value as the "unsmoothed" building blocks revenue stream. The implication of this process is that the (within period) costs associated with a lumpy capital project will be smoothed across the entire regulatory period, implying an element of pre-funding.

Furthermore, the Commission does not reconcile its assumption of excess profits with Transpower's self-imposed zero economic profit constraint through its EV adjustments. This in itself casts significant doubt on how Transpower could ever earn excess profits in anything but the short-run. Under the EV adjustments economic gains and losses are accumulated with interest charged at a rate equal to WACC, and adjustments to revenue are made on the basis of the balance of the accumulated gains and losses, as well as forecast gains and losses for the current and future years. This process ensures that, over time, the economic profit made by Transpower is zero, assuming that (a) Transpower has employed the appropriate WACC, and (b) all costs are efficient.

The risk with the Commission's approach is that it is eliminating revenues that are in fact required by Transpower to cover efficient costs. As well as sending a poor signal to investors about the level of analysis required before intervention, Transpower would also be forced to cut back efficient expenditure, which would likely have implications for service quality.

3.6. SUMMARY OF THE BENEFITS OF PRICE CONTROL

A comparison of the Commission's benefits with those presented in this section is set out in Table 8. Based on the Commission's assumption that Part F is not an effective constraint on Transpower we see little evidence that there would be significant benefit from introducing price control on Transpower. Where Part F is a binding constraint there is no evidence to support the Commission's findings.

Table 8: Comparison of potential benefits of price control: Commission's assessment and CRA analysis ($m)

Benefit	Commission Estimate	Recalculated Estimate	Comment (assuming Part F not binding)	Comment (assuming Part F binding)
Investment efficiency gains - NPV of 5% reduction in investment costs - NPV of 10% reduction in investment costs	 $117m $234m	 $82m $164m	May be a legitimate benefit.	Any gains are a result of Part F not price control
Improved timing of investment - NPV of a 1 year deferral of planned NI Upgrade Project - NPV of a 1 year deferral of planned investment programme - NPV of a 3 year deferral of planned investment programme	 $31m $148m $405m	 Max $117m	Investment delay is more likely to result in net costs than net benefits	No benefits (by definition)
Total investment efficiency gains and improved timing of investments	$148m-$639m	Maximum $266m		
Lower cost implementation of investment	Significant, but unquantified		Unlikely to be significant. Benefits are unlikely to arise due to Transpower's existing commercial incentives.	No benefits (by definition)
More efficient time profile of prices	Significant, but unquantified		No evidence to support existence of benefits.	No evidence to support existence of benefits.
Limitation of excess profits in 2006/07	$36m		Commission has not determined these are excess profits. Likely to reflect timing issues. In a well defined factual scenario these excess profits may be strongly negative.	Commission has not determined these are excess profits. Likely to reflect timing issues. In a well defined factual scenario these excess profits may be strongly negative.

4. COSTS OF CONTROL

The costs of regulation will depend significantly on the form of control. As noted above, the Commission has not specified this at this stage, and accordingly it is not possible to rigorously analyse costs.

The issue is particularly complicated in the case of Transpower, because the investment approval process is administered by the Electricity Commission, not the Commerce Commission. The issue is further complicated by the fact that the Electricity Commission is a new organisation implementing new processes, guidelines and rules with respect to transmission investment. And finally, complications arise because of the very clear need for investment in transmission and transmission alternatives throughout New Zealand.

Clearly, coordination issues between the Electricity Commission and the Commerce Commission will be critical, particularly as regards matters of process and expectation. For example, if the Commerce Commission sets a price cap for Transpower, how would that cap be reconciled with the possibility that the Electricity Commission approved significant elements of the grid upgrade plan in which significant capital investments are scheduled during the life of the cap?

The uncertainty raised by the regulatory set-up for Transpower is a concern.

The most important costs of regulation relate to its impact on investment. While the Commission has raised the NPV benefit of deferred capital expenditure as a benefit of control, no consideration has been paid to the potential costs associated with delay of investment. If price control results in delay when investment should have proceeded as planned, then the costs of delay will be incurred. Delay in grid investment has two key costs:

- The costs of unserved energy; and
- The costs associated with reducing competition in the electricity market by reducing investment in the grid relative to alternative scenarios, which results in increased constraints and increased localised market power concerns.

Each of these is potentially significant, and has been a significant source of value associated with grid investment in the past.

4.1. COST OF UNSERVED ENERGY

Unserved energy (or lost load) arises either as a result of an outage or because the System Operator requests that supply is reduced in order to keep the transmission system within safe operating limits.

To the extent that control could delay transmission investment necessary to ensure continued supply to a region (such as Auckland or the upper South Island) then control could result in unserved energy. Unserved energy represents an economic cost that should be included within a cost benefit analysis. Unserved energy may not eventuate if other steps are taken to avoid a situation in which unserved energy would otherwise occur, such as through demand management or investment in transmission alternatives. To the extent that other actions are taken, the issue becomes one of identifying the increased costs associated with having denied an appropriate consideration of transmission versus transmission alternative options. That is, by denying access to the prospect of a more optimal investment profile over time.

Given the shortness of the submission timeframe, it has not been possible to quantify the potential cost of unserved energy in any detail, and nor has it been possible for us to confirm the cost of unserved energy that Transpower has included in its investment proposal for the North Island 400kV Upgrade.

However, it is possible to calculate the NPV of unserved energy that might plausibly eventuate from a delay in the 400kV upgrade if no other means of satisfying the unserved load eventuated.

To conduct this analysis, we adopted the following process:

1. Establish the maximum allowable load in the Auckland and North Isthmus region, assuming no investment. The maximum allowable load should take account of the maximum safe operating limit that is likely to be imposed by the System Operator, as well as any low-cost interruptible demand;

2. Obtain peak demand forecasts from the Initial SOO, and then extrapolate those forecasts to obtain peak forecasts at narrower likelihood bands;

3. Apply an estimate of the Auckland and North Isthmus load duration curve to calculate the load that would not be served under each peak forecast;

4. Calculate the probability-weighted unserved energy;

5. Apply the “Value of Lost Load” (VOLL) from the Grid Investment Test to calculate the cost of unserved energy;

6. Calculate the cumulative NPV of the cost of unserved energy in each year; and

7. Calculate the increase in the NPV of unserved energy that would result from a delay in investment as the difference between the cumulative NPV in each year.

Each of these steps is described in more detail below.

This approach only looks at unserved energy arising from demand being greater than line capacity and as a result may understate the impact of project delays. An additional source of unserved energy is from equipment outages – whether planned or forced. An outage effectively reduces available capacity and increases the risk of unserved energy, and this risk increases almost exponentially as circuits become more heavily loaded as demand grows. While the probability of an outage may be low the impact will be significant in terms of unserved energy. One outage may cost $8-10million.

Transpower has estimated that the maximum operating limit for transfer into Auckland is 2,500MW. The System Operator applies a 5% safety margin to this limit, so the Safe Operating Limit is 2,375MW. However, the Electricity Commission notes that there could potentially be 70-200MW of low cost interruptible load available in the Auckland region.[30] For the purpose of our analysis, we can add the interruptible load to the transfer limit to obtain a maximum servable demand of 2,445MW – 2,575MW. We also add the cost of interruptible load to our final results.[31]

For each major region in the transmission system the Initial SOO provides the forecast regional after diversity peak for each year from 2005-2025. We have added together the forecasts for the Auckland and North Isthmus regions to obtain a combined forecast for demand that needs to be satisfied by generation in the area and transfers into the Auckland region. We have not applied any factor to adjust for diversity that might exist between the Auckland and North Isthmus load,[32] and nor have we increased the North Isthmus load to reflect the electrical losses that would be incurred in transmitting the necessary electricity through the Auckland region.

The Electricity Commission provides mean, low (90% probability of exceedance (POE)), and high (10% POE) forecasts. From these forecasts we have calculated the peak demand forecast for 2.5% POE, 10% POE, 20% POE, 30% POE, 40% POE, 50% POE, 60% POE, 70% POE, 80% POE, and 90% POE. Our calculations are shown in Appendix C.

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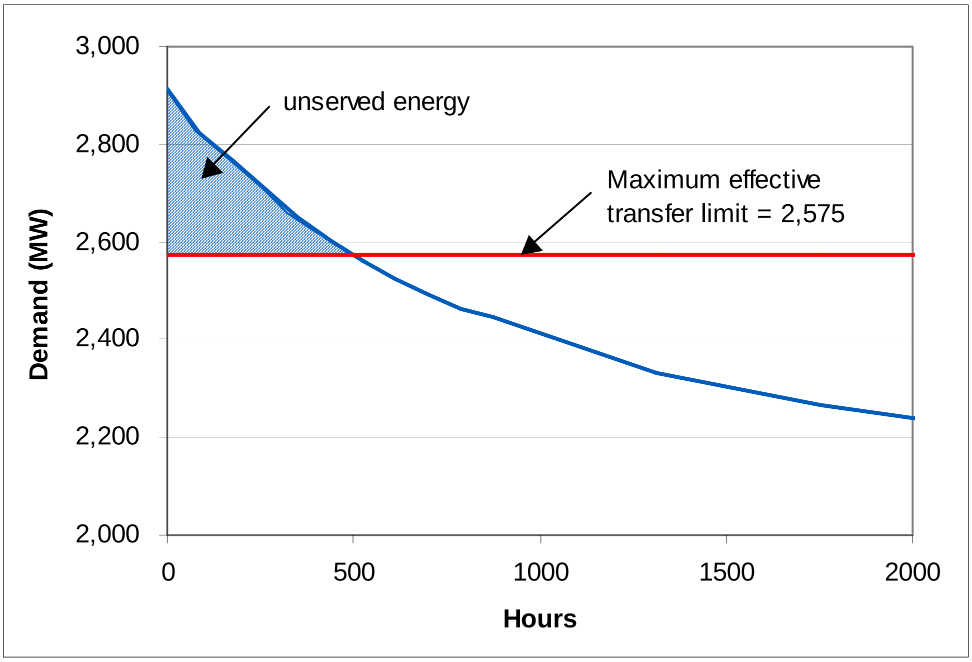
30 Electricity Commission, *Alternatives to Transpower's Proposed Whakamaru-Otahuhu 400kV Transmission Line: Alternatives Analysis Stage II*, December 2005, pp. 35-36, and discussion in paragraphs 276-277 (no page numbers).

31 The Electricity Commission (op cit) provides an indicative cost of $0.015m/MW for interruptible load. Assume that the quantity of interruptible load is equal to the amount by which peak load exceeds the safe operating limit, up to the maximum of 200MW of interruptible load. The weighted average quantity of interruptible load is 0.7MW in 2009, 14.2MW in 2010, 53.6MW in 2011, 103.1MW in 2012, and 142.2MW in 2013. Applying the indicated cost of interruptible load, inflating by CPI of 2% per year, and discounting at 10% provides a cumulative NPV of interruptible load of $0.2m in 2010, $0.7m in 2011, and $1.5m in 2012. In the case where the maximum interruptible load is 70MW, the cumulative NPV is $0.1m in 2010, $0.4m in 2011, and $0.9m in 2012.

32 Diversity occurs when the peaks in two locations do not occur at the same time, so the combined peak is less than the sum of the two individual peaks.

A load duration curve represents the number of hours in a year that load is at or above any given level. As we shall show, a load duration curve can be used to calculate the unserved energy when demand exceeds a specified level. We have estimated the Auckland and North Isthmus load duration curve from information that Transpower has previously supplied to the Electricity Commission.[33] For each year and each POE scenario we scaled the load duration curve so that the peak was equal to the forecast peak. As shown in Figure 1, the portion of the load duration curve that lies above the maximum servable demand represents the unserved energy.

Figure 1: Calculation of Unserved Energy for 10% POE Demand Forecast, 2015



Source: CRA calculations.

The Grid Investment Test requires that unserved energy is valued at $20,000/MWh.[34] This is also known as the "Value of Lost Load" (VOLL). We apply VOLL to the expected unserved energy to calculate the expected nominal cost of unserved energy.[35] We then calculate the cumulative NPV of the cost of unserved energy using the discount rate of 10% that the Commission applied to the calculation of the benefits of control. Table 9 shows the calculation of the cumulative NPV of unserved energy for 70MW of interruptible load and for 200MW of interruptible load.

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33 Transpower, *Request for Information paper: Alternatives to transmission investment for meeting future electricity supply requirements for Auckland and North Isthmus*, September 2004, p. 9

34 See Rule 8.3.4 of Schedule F4.

35 Note that we inflate VOLL at CPI to reflect the fact that we are using a nominal discount rate. If a (lower) real discount rate was used then a constant value of VOLL would be applied. CPI is assumed to be 2% per year.

Table 9: Calculation of the Cost of Unserved Energy from No Investment

	70 MW Interruptible Load			200 MW Interruptible Load		
	Expected Unserved Energy (GWh)	Nominal Cost of Unserved Energy ($m)	Cumulative NPV ($m)	Expected Unserved Energy (GWh)	Nominal Cost of Unserved Energy ($m)	Cumulative NPV ($m)
2006	-	-	-	-	-	-
2007	-	-	-	-	-	-
2008	-	-	-	-	-	-
2009	-	-	-	-	-	-
2010	0.1	1.4	0.9	-	-	-
2011	1.2	27.6	16.4	0.0	0.3	0.2
2012	6.1	137.5	87.0	0.6	13.1	6.9
2013	17.3	396.9	272.1	3.5	80.2	44.3
2014	36.3	851.8	633.4	10.9	254.9	152.4
2015	65.7	1,570.4	1,238.8	25.0	598.2	383.0
2016	106.2	2,588.3	2,146.0	47.0	1,146.2	784.7

Source: CRA calculations. See Table 19 and Table 20 in Appendix C.

We now have the information necessary to assess the impacts of a delay in commissioning of the 400kV upgrade. Transpower has publicly stated that it is necessary for new transmission assets to be commissioned by 2010 in order to avoid outages in Auckland. Table 9 shows that if the upgrade is commissioned before 2010 there will be no unserved energy. With one year's delay to commissioning in 2010, the NPV cost of unserved energy ranges between $0.0m and $0.9m. Adding the cost of interruptible load, the NPV ranges from $0.2m (with 200MW of interruptible load) to $1.0m (with 70MW of interruptible). With two year's delay the NPV cost of unserved energy is $0.9m to $16.8m, and with three year's delay the NPV cost increases significantly to $8.4m to $87.9m.

We note that the Electricity Commission does not contest Transpower's conclusion that investment is required by 2010. In the Initial SOO, the Electricity Commission found that "

> *it will be necessary to augment the supply into the Auckland region by 2010 in order to continue meeting the N-1 security criterion.*[36]

The Electricity Commission does, however, appear to suggest that it may be possible to defer a major upgrade until around 2017. The impact of such a delay on both the counterfactual and factual revenue profiles would be able to be tested with a comprehensive building block analysis.

36 Electricity Commission, *Initial Statement of Opportunities*, p. 7. See also Electricity Commission, *Alternatives to Transpower's Proposed Whakamaru-Otahuhu 400kV Transmission Line: Alternatives Analysis Stage II*, December 2005, p. 7.

More important for our current analysis is the difference between delays that might arise as a result of the Part F process and delays that might be caused as a result of cash flow restrictions arising from price control. If investment is required to meet the Grid Reliability Standards, then the Electricity Commission will only delay transmission investment if it considers that there are sufficient transmission alternatives available at a lower cost than transmission. The Electricity Commission is currently undertaking this analysis. Our analysis has assumed that 70MW – 200MW of interruptible load is available, but the Electricity Commission may conclude that other alternatives to Transpower's proposed upgrade are appropriate.

The form of price control has not been specified by the Commission and therefore it is not possible to identify whether Transpower's revenue profile under price control would be sufficient to allow the North Island 400kV upgrade to proceed. However, it is likely that the 400kV upgrade would not be able to proceed, or would be subject to significant delays, if Transpower were to be restricted to a revenue profile equal to that under the current threshold. If this resulted in a delay of three or more years in the commissioning of the 400kV upgrade, beyond any delay resulting from Part F, then the cost of unserved energy could be very significant.

4.2. COST OF REDUCED COMPETITION

When evaluating the costs of controls that can limit grid investment, an important consideration is what benefits grid investment would otherwise potentially create. One of the important benefits of grid enhancement is in the area of increased competition and reduced constraints. In essence, grid investment increases the ability of competitors to reach each location in the grid at all relevant times. In a small market like New Zealand this can be particularly important.

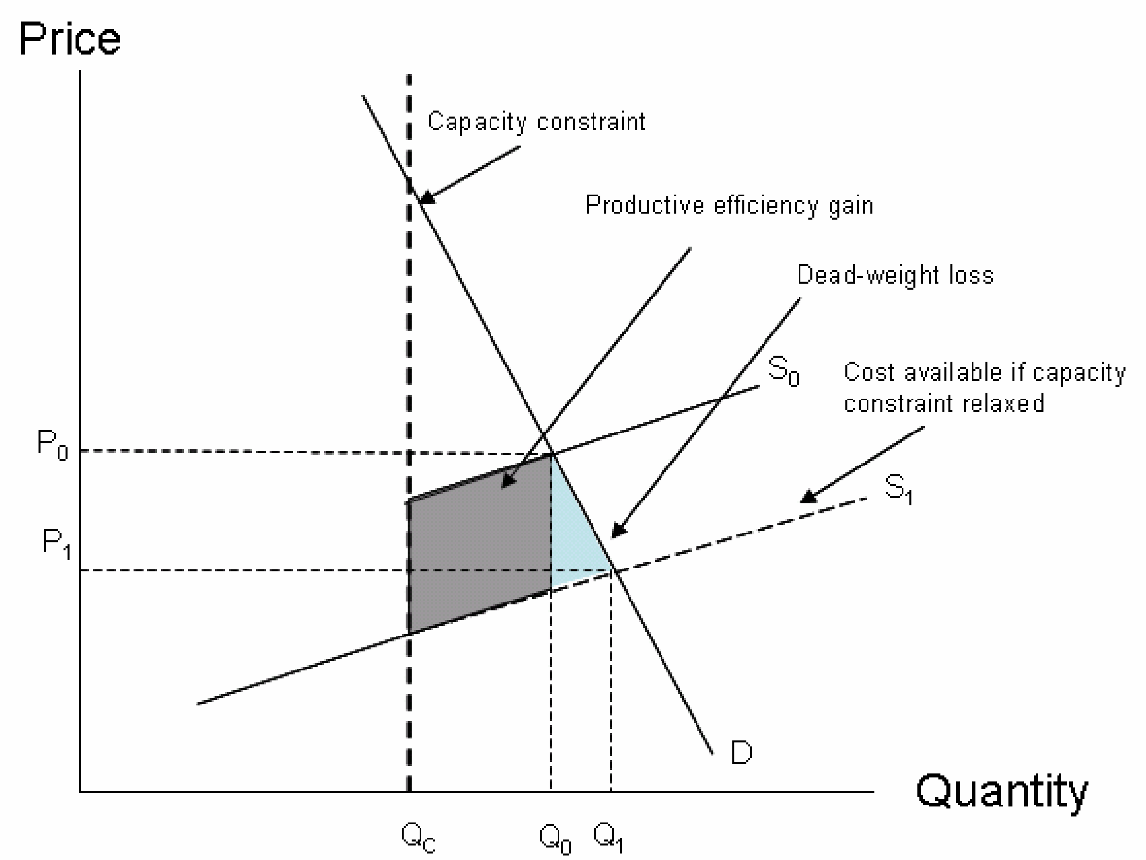
The competition costs of delayed transmission investment can probably best be understood by considering the benefits of transmission investment – delayed investment would result in the foregoing of these benefits (a "missing market" analysis). The benefits of a transmission investment include:

- Entry of lower cost generation into a previously supply constrained area (supply curve shifts right, price drops and quantity increases, total surplus increases, in both the spot and the hedge markets);
- Mitigation of market power – increase in the intensity of competition in a less than fully competitive market (price drops/quality increases,[37] quantity increases, total surplus increases, in both the spot and hedge markets); and
- Dynamic efficiency gains (including deferred or avoided investment in relatively high cost generation (potentially demand-side investment as well)).[38]

37 For example, increased competitive pressure may result in hedges being offered with increased flexibility as to risk allocation.

The static benefits of relaxing a capacity constraint are illustrated in the diagram below.[39]

Figure 2: Benefits of removing a capacity constraint



In Figure 2 P_0, Q_0 is the price and quantity produced when demand in the market exceeds Q_C – the point at which the capacity constraint becomes binding, and market prices are set by high cost in-region suppliers (supply curve S_0). P_1,Q_1 represents the price and quantity that would prevail absent that constraint, when the capacity constraint is relieved and low cost suppliers can supply the market (supply curve S_1). This analysis assumes the market is fully competitive, and market prices are set by production costs at the margin.

38 Potentially the opposite effects will occur in the exporting area.

39 This diagram is conceptual. For example, in reality the alternative supply curves might have quite different slopes.

The economic benefits to this change come in two forms. First, the volume that was previously produced at high cost (Q_0 - Q_C) is now produced at a lower cost. This efficiency gain adds to total surplus. Second, the lower cost causes a price fall from P_0 to P_1. The fall in price increases quantity consumed from Q_0 to Q_1, with the triangular dead-weight loss area representing the surplus gained. The total surplus increase is the benefit from the investment that expands the available capacity, all else equal.

As noted, this analysis assumes competitive behaviour. It is possible that there may be both market effects arising directly from changing the physical constraints (expanding transmission capacity) and from changes in behaviour that also result. The impact of assuming such a change is not difficult to analyse at the conceptual level – see Figure 3 below.

Figure 3: Impact of Capacity Expansion that removes Market Power

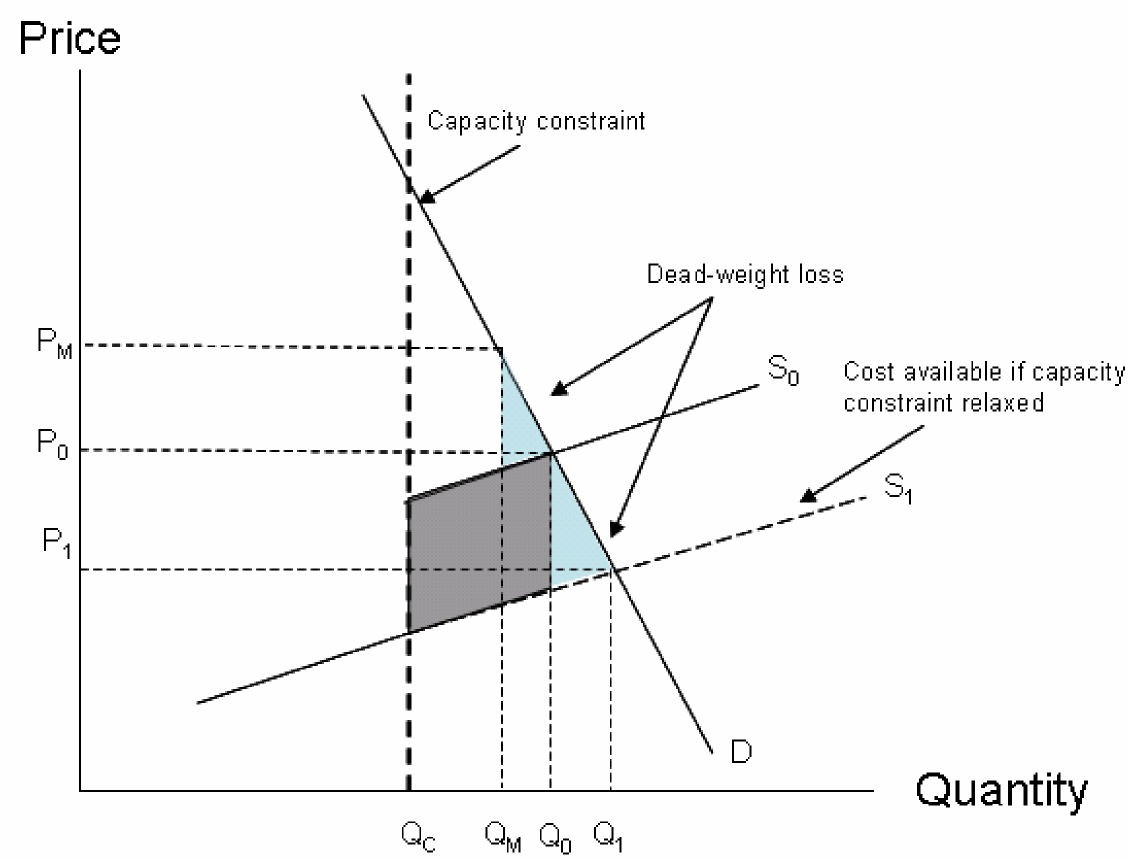


Figure 3 shows a simple illustration of a situation where market power is believed to exist prior to the capacity expansion and prices are set at the level P_M,Q_M. In the simplest case, where the expansion transforms behaviour to fully competitive, then the additional surplus gained from restoring effective competition is the additional dead-weight loss regained as a result of market prices falling from P_M to P_0. This would be added to the benefits of expansion that result from the shift in the supply curve from S_0 to S_1.

Given the short time frame available to respond to the Commission's Intention to Declare Control of Transpower, we have been unable to quantify the magnitude of the competition costs of control. Importantly, however, we note that competition benefits are maximised from an investment programme that reduces constraints and that supports a broader range of long-term generation responses (from more regions). Thus, these benefits are likely to be maximised through larger transmission investment undertakings rather than smaller "just in time" upgrades.

5. OTHER IMPACTS OF CONTROL

Further implications of price control arise from the effect of price control on the allocation of risks. Declaration of price control over an extended period shifts considerable risk from customers to Transpower, and Transpower should be compensated for bearing those risks. The magnitude of the required increase in revenue requirement is discussed in Section 5.1 below. Alternatively, the Commission may seek to eliminate the $36m of claimed excess profits, and potentially seek other efficiencies. This implies a reduction in revenues, which in turn increases debt costs. These are quantified in Section 5.2.

5.1. BUILDING BLOCK REVENUE REQUIREMENT

The purpose of any factual revenue stream should be to reflect the revenue that would apply under price control. Transpower's currently advised prices for the year ending 31 March 2007 have been derived with a WACC of 7.3%.[40] This is significantly lower than a plausible WACC for price control based on statements by the Commission and its advisors. In Appendix A we set out a plausible range for the WACC under price control based on the Commission's past practice and statements. We note that a WACC of 9.2% for price control is supported on this basis. The higher WACC reflects the transfer of risk from consumers to Transpower under a five-year price control arrangement.

This suggests that under price control Transpower's building block revenue requirement should be higher than the revenue currently calculated by Transpower, all else being equal. The increase in revenue requirement will reflect an additional 190 basis point return on capital, plus the additional taxes payable on the higher revenue. Applying the corporate tax rate of 33%, the increase in revenue requirement is a 2.83% return on capital.[41]

Table 10 shows the calculation of the increase in revenue requirement under price control. We have calculated the Regulatory Asset Base as the opening net book value plus half capital expenditure.[42] The NPV of the revenue increase is $307.6m.

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40 Transpower, *Pricing for Grid Connection Services from 1 April 2006*, Appendix K, p. 32.

41 The post-tax WACC of 9.2% translates to a pre-tax WACC of 9.2%/(1-0.33) = 13.73%. The post-tax WACC of 7.3% translates to a pre-tax WACC of 7.3%/(1-0.33) = 10.90%. The increase in the pre-tax WACC is 13.73% - 10.90% = 2.83%.

42 In our report in response to the Commission's intention to declare control of Unison Networks Ltd we demonstrated that the Regulatory Asset Base should be calculated in this manner in order for the NPV of earnings over the life of an asset to equal the initial capital cost of the asset. See CRA International, *Review of the Commerce Commission's Intention to Declare Control of Unison*, prepared for Unison Networks Limited, 28 October 2005, pp. 29-30.

Table 10: Calculation of Increased Revenue Requirement under Price Control

Year	Opening Net Book Value	Capital Expenditure	Regulatory Asset Base	Revenue Increase
2006/07	2,095	463	2,327	65.8
2007/08	2,380	481	2,620	74.2
2008/09	2,607	667	2,941	83.2
2009/10	2,777	747	3,151	89.2
2010/11	3,370	431	3,586	101.5
NPV				**307.6**

Source: Opening Net Book Value and Capital Expenditure from Transpower. Discount rate is 10%.

5.2. DEBT COSTS

Even though we consider that it is appropriate for revenue under price control to reflect a price control WACC, we do not know what level of factual revenue the Commission considers appropriate. It may well be that the Commission would instead act to remove what it has identified as "excess profits", notwithstanding the fact that the "excess profits" are merely a breach of the thresholds rather than excess profits identified through either an analysis of Transpower's return on assets or by the construction of a building block revenue requirement. In this case, Transpower's revenue under price control would be less than Transpower's building block calculation of revenue.

Revenue reductions have two effects leading to a higher debt cost:

- First, lower revenues mean that Transpower must borrow more to fund projected levels of investment; and
- Second, lower revenues and higher debt levels adversely affect Transpower's credit rating, leading to a higher interest rate (cost of debt).

First NZ Capital have estimated the impact of a reduction in revenue on Transpower's cost of debt.[43] Table 11 summarises the conclusions from the First NZ Capital report, and then uses that information to calculate the cost of debt for different levels of revenue.

43 First NZ Capital, *Report on Cost of Debt of Transpower NZ Limited*, February 2006.

Table 11: Estimates of the Impact of a Revenue Reduction on Transpower's Cost of Debt

Scenario	Credit Rating	Margin (bps over AA Rating)	Debt Margin (bps)	Cost of Debt
Counterfactual	AA	0	100	7.30%
10% Revenue Reduction	A	22	122	7.52%
20% Revenue Reduction	A	22	122	7.52%
30% Revenue Reduction	BBB	55	155	7.85%

Source: First NZ Capital, *Report on Cost of Debt of Transpower NZ Limited*, February 2006, pp. 21-22. Debt Margin of 100bps for an AA credit rating is based on Transpower's current WACC calculation. The implied risk-free rate of 6.3% is taken from the Commission's WACC calculation.

Table 12 calculates the increased debt costs that arise with lower revenues. The first panel shows Transpower's projections of the level of gross interest bearing debt under each scenario. The second panel then calculates the cost of debt as the product of the gross interest bearing debt and the relevant cost of debt from Table 11. Comparing the NPV of debt costs indicates that a 10% revenue reduction would lead to $56.2m of additional debt costs, a 20% revenue reduction would lead to $96.7m of additional debt costs, and a 30% revenue reduction would lead to $166.3m of additional debt costs. Even a 10% reduction in revenue leads to additional debt costs that are higher than the $36m of supposed "excess profits". Note that these calculations understate the full impact on debt costs, as Transpower would continue to bear additional debt costs for many years beyond the control period.

Table 12: Increased Debt Costs with Lower Revenues

	2006/07	2007/08	2008/09	2009/10	2010/11	NPV ($m)	Increment ($m)
Gross Interesting Bearing Debt							
Counterfactual	1,326	1,567	1,962	2,423	2,543		
10% Revenue Reduction	1,372	1,658	2,106	2,629	2,818		
20% Revenue Reduction	1,418	1,749	2,251	2,836	3,094		
30% Revenue Reduction	1,464	1,840	2,395	3,042	3,370		
Debt Costs							
Counterfactual	96.8	114.4	143.2	176.9	185.6	526.2	
10% Revenue Reduction	103.2	124.7	158.4	197.7	211.9	582.4	56.2
20% Revenue Reduction	106.6	131.5	169.3	213.3	232.7	622.9	96.7

30% Revenue Reduction	114.9	144.5	188.0	238.8	264.5	692.5	166.3

Source: Gross Interest Bearing Debt from Transpower; Debt Costs calculated by CRA. Discount rate is 10%.

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APPENDIX A: WEIGHTED AVERAGE COST OF CAPITAL

This appendix sets out potential WACC values that could be applied in a building blocks assessment of Transpower. These potential WACC values are derived exclusively from the Commission's past approach to WACC and do not reflect our own preferred approach. (For an example of our own approach to cost of capital issues, see our report for Vector, and filed with the Commission, entitled "Response to the Commission's Draft Guidelines on the Cost of Capital", dated December 2005.)

Based on the Commission's past statements and decisions, the feasible range for the WACC in any Stage 2 investigation into Transpower falls between two values:

- A WACC of 9.2%, based on the upper standard deviation of a WACC derived from parameters applicable for a 5-year price control period; and
- A WACC of 7.35% representing the Commission's "excess profit" WACC for the electricity lines businesses.

The parameter values consistent with these estimates are set out in Table 13.

Table 13: Transpower WACC assuming Commission past practice on WACC parameters

Parameter	5-year price control period	Standard deviation	"Excess profit" WACC	Standard deviation
Risk free rate	6.30%		6.30%	
Debt margin	1.20%		1.20%	
Cost of debt	7.50%		7.50%	
Market risk premium	7.0%	1.5%	7.0%	1.5%
Asset beta (US)	0.30	0.10	0.30	0.10
Asset beta (5-year price cap increment)	0.20	0.075	0.20	0.075
Relative riskiness of NZ business	1.00	NA	0.50	0.33
Asset beta	0.50	0.125	0.40	0.128
Leverage	40%		40%	
Equity beta	0.83		0.67	
Cost of equity	10.05%		8.89%	
WACC	8.05%	1.17%	7.35%	1.10%

Note that the values included in this table do not represent an endorsement of the Commission's position or preferred values of CRA International.

We consider three aspects of these calculations:

- Why the WACC that would be applicable under price control is applicable in the development of a factual revenue stream for Transpower;
- The values for the particular WACC parameters based on the Commission's most recent considerations on WACC; and
- The appropriate point within the WACC distribution.

A.1 WHY THE WACC SHOULD REFLECT THE VALUE APPLICABLE UNDER PRICE CONTROL

In his latest paper written for the Commission,[44] Associate Professor Lally (implicitly) sets out two distinct WACC values: a WACC applicable for assessing the existence of excess profits for firms operating under the threshold regime; and a WACC applicable for a firm subject to price control.

In developing a factual revenue stream, the WACC that is applied should reflect the value that would be applicable for Transpower under price control. This is because the Commission is considering an explicit case for price control. This means that the parameter values underpinning the WACC for an investigation on the net benefit of introducing price control should be drawn from the same distribution as the parameters that would apply under explicit price control. If this is not the case, the analysis is internally and logically inconsistent. This is because the benefits (and costs) of introducing price control would be assessed against an environment that may bear little resemblance to the conditions under which price control would actually be introduced.

Assessing the parameter values and ranges that would apply to the WACC under price control is made complicated by the fact that the Commission has not set out how price control would be implemented. However, at a "high level" the Commission's price control WACC could be used in any analysis assuming the circumstances surrounding the introduction of price control would match the circumstances underpinning previous estimates of applicable parameter values.

A.2 PARAMETER VALUES

The assumption adopted on each parameter value is briefly explained.

- The estimate of the risk free rate is based on the value used by Associate Professor Lally in his September 2005 paper for the Commission (6.30%);

44 Lally, M 2005. The Weighted Average Cost of Capital for Electricity Lines Businesses.

- The estimate of the debt margin is taken as the value recommended by Associate Professor Lally (1.20%). This is based on adjusting his recommendation for the airfields inquiry (1.00%) for higher operating risk, plus some limited evidence on market yields for debt issued by Powerco and Vector.[45] This estimate may understate the Commission's position as it does not include any allowance for debt issuance as recommended by Associate Professor Lally;[46]

- A Market Risk Premium of 7% with standard deviation of 1.5% is assumed based on the Commission's approach in its gas inquiry and the recommended of Associate Professor Lally for the electricity lines businesses;

- An asset beta of 0.40 is assumed under the "excess profit" scenario, while an asset beta of 0.50 is assumed for a 5-year price control period. These are based on the advice of Associate Professor Lally. The respective standard deviations are 0.125 in the case of a 5-yearly price cap regime and a standard deviation of 0.128 under the "excess profit" scenario;[47] and

- A common estimate of 40% has been used based on the recommendations of Associate Professor Lally to the Commission.

A.3 APPLICABLE VALUE WITHIN THE RANGE

An upper standard deviation range has been applied on the price control WACC based on the advice of Associate Professor Lally plus the Commission's practice in its gas inquiry and investigation into Unison. Associate Professor Lally states:[48]

> *Second, the estimation of WACC in the earlier investigation may employ bands to reflect uncertainty about the true value of this parameter. However, in respect of setting a price cap, a single number must be settled upon. That number might be drawn from the upper or lower end of the distribution rather than the middle. I favour drawing it from the upper end, because the consequences of setting the WACC too low (in the form of deterring investment) are more severe than the consequences of setting it too high (in the form of imposing excessive prices upon consumers).*

45 Lally 2004, p. 55.

46 Lally 2005, p. 57.

47 Associate Professor Lally develops his estimate of the asset beta under price control from his estimate of the asset beta for US electricity companies subject to rate of return regulation. The three variables used are: a) Asset beta for US firms subject to rate of return regulation: 0.30 with standard deviation of 0.10; b) Increment on asset beta to moving towards UK style price cap regulation: 0.20 with standard deviation of 0.75; and c) Multiplier on the increment to reflect where the New Zealand businesses are on this continuum: 0.50 in the case of the thresholds; 1.00 in the case of 5-yearly price control (standard deviation of 0.33).The standard deviation for price control then becomes $((0.10)^{2}+(0.075)^{2})^{0.5}$

48 Lally 2005, page 103.

In its gas inquiry, the Commission used a 75th percentile WACC value as part of sensitivity testing on its modelling results. In its Intention to Declare Control on Unison it applied a sensitivity equal to a WACC one standard deviation above the mean, equivalent to a 83rd percentile value.

Applying a one-standard deviation range on the Commission's estimates produces an upper-range WACC of 8.45% based on an excess profit WACC and an upper-range WACC of 9.2% based on a 5-year price control period.

APPENDIX B: CALCULATION OF COMBINED DEFERRAL BENEFITS AND BENEFITS FROM INVESTMENT EFFICIENCY GAINS

In Table 14 we calculate the benefit of a 1 year deferral of the HVDC upgrade, both under a 5% and a 10% efficiency gain. For simplicity, and consistent with our calculations of efficiency benefits, we have assumed that all HVDC expenditure outside the control period still benefits from the efficiency gains because it was subject to Electricity Commission decision making during the control period. The first row of each panel shows the revised capital expenditure after the application of the efficiency gains. The second row of the panel defers the capital expenditure by 1 year. The third row applies 1 year of inflation to the deferred capital expenditure. These calculations show that deferral benefits for the HVDC upgrade are $23.9m-$25.2m, somewhat less than the $31.2m claimed by the Commission.

Table 14: Benefits from a 1 Year Deferral of the HVDC Upgrade ($m)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	NPV
Original Capex	6.1	30.4	27.4	106.6	294.2	103.0	0.7	-	-	
10% Efficiency Gains										
Revised Capex	5.5	27.4	24.7	95.9	264.8	92.7	0.6	-	-	328.7
1 Year Delay	-	5.5	27.4	24.7	95.9	264.8	92.7	0.6	-	
Inflated	-	5.6	27.9	25.2	97.9	270.1	94.6	0.6	-	304.8
Savings										**23.9**
5% Efficiency Gains										
Revised Capex	5.8	28.9	26.0	101.3	279.5	97.9	0.7	-	-	347.0
1 Year Delay	-	5.8	28.9	26.0	101.3	279.5	97.9	0.7	-	
Inflated	-	5.9	29.5	26.6	103.3	285.1	99.8	0.7	-	321.7
Savings										**25.2**

Source: CRA calculations. Discount rate is 10%.

In Table 15 we calculate the benefits from a 3 year deferral of the North Island 400kV project, again both under a 5% efficiency gain and a 10% efficiency gain. Capital expenditure projections for the 400kV upgrade were provided by Transpower. The calculations show that deferral benefits for the North Island 400kV upgrade are $55.6m-$68.4m.

The first row of each panel shows the revised capital expenditure after the application of the efficiency gains. The second row of the panel defers the capital expenditure by 3 years. The third row shows the efficiency gains arising on the deferred capital expenditure, but only if the deferred capital expenditure falls within the control period. The fourth row shows the inflation adjustment to the deferred capital expenditure. The inflation gain is applied to the sum of the deferred capital expenditure and the efficiency gain. Inflation is calculated at the rate of 2% per year. The final row in each panel adds together the capital expenditure as the deferred capital expenditure plus any efficiency gain plus the inflation adjustment.

Table 16 and Table 17 show our calculation of the combined benefits from deferral benefits and investment efficiency gains for a 3 year deferral relating to those parts of Transpower's capital expenditure programme that are subject to Electricity Commission jurisdiction. Capital expenditure that is not subject to Electricity Commission jurisdiction is not included in the calculation of deferral benefits.

When calculating the benefits of deferral, any capital expenditure that is subject to Electricity Commission jurisdiction should reflect the assumption of 5%-10% efficiency gains, otherwise double counting will occur. The first panel of each table shows the calculation of benefits from investment efficiency gains. The second panel shows the calculation of deferred non-HVDC capital expenditure, and the third panel shows the calculation of deferred HVDC capital expenditure – both these panels are structured in the same manner. The first row in the respective panels shows the capital expenditure that has not been deferred, together with any efficiency gain that has already been included in the calculation of the benefits from investment efficiency gains. The second row in the panel shows the portion of the capital expenditure that has been deferred – this refers to the capital expenditure before efficiency gains are deducted. As discussed in Section 3.2, 25% of non-HVDC capital expenditure and 100% of HVDC capital expenditure is deferred. The third row shows the efficiency gains arising on the deferred capital expenditure. We assume that efficiency gains only arise if the deferred capital expenditure is incurred during the control period. The fourth row in the panel shows the inflation adjustment to the deferred capital expenditure. This is calculated at the rate of 2% per year, and is calculated on the sum of the deferred capital expenditure and the efficiency gain. The final row in the panel adds together the total capital expenditure.

The second-to-last row of each table is labelled the "Total including deferrals" – this is the sum of the "Non-HVDC Subtotal" and the "HVDC Subtotal". This is then compared with the "Capex After Efficiency Gains" to obtain the deferral benefit.

Table 15: Benefits from a 3 Year Deferral of the North Island 400kV Upgrade ($m)

	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	NPV
Original	28.3	84.4	92.6	106.4	203.8	-	-	-	-	400.8
Include Efficiency in Deferral		Y	Y	Y	Y	Y				
10% Efficiency Gains										
Revised	25.5	76.0	83.4	95.8	183.4	-	-	-	-	360.7
3 Years Delay	-	-	-	28.3	84.4	92.6	106.4	203.8	-	
Efficiency Gain on Deferral	-	-	-	(2.8)	(8.4)	(9.3)	-	-	-	
Inflation on Deferral	-	-	-	1.6	4.7	5.1	6.5	12.5	-	
Total	-	-	-	27.0	80.7	88.5	112.9	216.2	-	305.0
Savings										**55.6**
5% Efficiency Gains										
Revised	26.9	80.2	88.0	101.1	193.6	-	-	-	-	380.7
3 Years Delay	-	-	-	28.3	84.4	92.6	106.4	203.8	-	
Efficiency Gain on Deferral	-	-	-	(1.4)	(4.2)	(4.6)	-	-	-	
Inflation on Deferral	-	-	-	1.6	4.9	5.4	6.5	12.5	-	
Total	-	-	-	28.5	85.1	93.4	112.9	216.2	-	312.3
Savings										**68.4**

Source: CRA calculations. Discount rate is 10%.

Table 16: Calculation of Deferral Benefits, All Capital Expenditure, 25% of Non-HVDC Delayed Three Years, 5% Efficiency Gain ($m)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	NPV
Original Capex Estimates										
Non-HVDC	355.2	384.1	433.8	436.0	224.3	-	-	-	-	1,403.3
HVDC	6.1	30.4	27.4	106.6	294.2	103.0	0.7	-	-	365.2
Total Subject to EC	361.3	414.5	461.2	542.6	518.5	103.0	0.7	-	-	1,768.6
Capex After Efficiency Gains	343.2	393.8	438.1	515.5	492.6	97.9	0.7	-	-	1,680.1
Efficiency Benefit	18.1	20.7	23.1	27.1	25.9	5.2	0.0	-	-	**88.4**
Include Efficiency in Deferral?	Y	Y	Y	Y	Y	N	N	N	N	
Non-HVDC	25% of Non-HVDC Deferred 3 years									
Non-deferred with Efficiency Gain	253.1	273.7	309.1	310.7	159.8	-	-	-	-	
Original Deferred				88.8	96.0	108.5	109.0	56.1	-	
Efficiency Gain on Deferral				(4.4)	(4.8)	-	-	-	-	
Inflation on Deferral				5.2	5.6	6.6	6.7	3.4	-	
Non-HVDC Subtotal	253.1	273.7	309.1	400.2	256.6	115.1	115.7	59.5	-	1,273.2
HVDC	100% of HVDC Deferred 3 years									
Non-deferred with Efficiency Gain	-	-	-	-	-	-	-	-	-	
Original Deferred				6.1	30.4	27.4	106.6	294.2	103.0	
Efficiency Gain on Deferral				(0.3)	(1.5)	-	-	-	-	
Inflation on Deferral				0.4	1.8	1.7	6.5	18.0	6.3	
HVDC Subtotal	-	-	-	6.1	30.6	29.1	113.1	312.2	109.3	289.7
Total including deferrals	253.1	273.7	309.1	406.3	287.3	144.2	228.8	371.7	109.3	1,562.9
Deferral Benefit	90.2	120.1	129.1	109.1	205.3	(46.3)	(228.1)	(371.7)	(109.3)	**117.2**

Source: CRA calculations.

Table 17: Calculation of Deferral Benefits, All Capital Expenditure, 25% of Non-HVDC Delayed Three Years, 10% Efficiency Gain ($m)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	NPV
Original Capex Estimates										
Non-HVDC	355.2	384.1	433.8	436.0	224.3	-	-	-	-	1,403.3
HVDC	6.1	30.4	27.4	106.6	294.2	103.0	0.7	-	-	365.2
Total Subject to EC	361.3	414.5	461.2	542.6	518.5	103.0	0.7	-	-	1,768.6
Capex After Efficiency Gains	325.2	373.1	415.1	488.3	466.7	92.7	0.6	-	-	1,591.7
Efficiency Benefit	36.1	41.5	46.1	54.3	51.9	10.3	0.1	-	-	**176.9**
Include Efficiency in Deferral?	Y	Y	Y	Y	Y	N	N	N	N	
Non-HVDC	25% of Non-HVDC Deferred 3 years									
Non-deferred with Efficiency Gain	239.8	259.3	292.8	294.3	151.4	-	-	-	-	
Original Deferred				88.8	96.0	108.5	109.0	56.1	-	
Efficiency Gain on Deferral				(8.9)	(9.6)	-	-	-	-	
Inflation on Deferral				4.9	5.3	6.6	6.7	3.4	-	
Non-HVDC Subtotal	239.8	259.3	292.8	379.1	243.1	115.1	115.7	59.5	-	1,214.2
HVDC	100% of HVDC Deferred 3 years									
Non-deferred with Efficiency Gain	-	-	-	-	-	-	-	-	-	
Original Deferred				6.1	30.4	27.4	106.6	294.2	103.0	
Efficiency Gain on Deferral				(0.6)	(3.0)	-	-	-	-	
Inflation on Deferral				0.3	1.7	1.7	6.5	18.0	6.3	
HVDC Subtotal	-	-	-	5.8	29.0	29.1	113.1	312.2	109.3	288.5
Total including deferrals	239.8	259.3	292.8	384.9	272.1	144.2	228.8	371.7	109.3	1,502.7
Deferral Benefit	85.4	113.8	122.3	103.4	194.5	(51.5)	(228.2)	(371.7)	(109.3)	**89.0**

Source: CRA calculations.

APPENDIX C: UNSERVED ENERGY CALCULATIONS

The Electricity Commission provides mean, low (90% probability of exceedance (POE)), and high (10% POE) forecasts. We have assumed that the upper portion of the peak distribution is normally distributed, which means that the Electricity Commission's high forecast is 1.282 standard deviations above the mean. Knowing the standard deviation, we can then calculate the demand forecast at more points on the distribution than what are provided by the Electricity Commission. We apply the same procedure to calculate the standard deviation for the lower half of the distribution and hence calculate forecasts from the lower part of the distribution.[49] From the mean and standard deviations when then calculate the peak demand forecast for 2.5% POE, 10% POE, 20% POE, 30% POE, 40% POE, 50% POE, 60% POE, 70% POE, 80% POE, and 90% POE. The demand forecasts are shown in Table 18.

Table 19 shows our estimates of unserved energy with 70MW of interruptible load, and Table 20 shows our estimates with 200MW of interruptible load. The second row in each table shows the probability of the particular forecast scenario occurring. The 2.5% POE forecast represents the range 0% POE to 5% POE, so the 2.5% POE forecast is given a 5% probability of occurring. The 10% POE forecast represents the range 5% POE to 15% POE, so the 10% POE forecast is given a 10% probability of occurring. The other POE forecasts presented also have a 10% probability of occurring. The final column in each table shows the expected value of the unserved energy, calculated as the probability-weighted average of the unserved energy under each POE forecast.

Note that the probabilities in the second row of Table 19 and Table 20 only add to 95% rather than 100%. This is because we have simply omitted the bottom 5% of the peak demand distribution. This has no effect on our calculation of the cost of unserved energy because for all years of interest, there is no unserved energy in that part of the distribution.

49 Note that the standard deviation from the upper half of the distribution is generally not equal to the standard deviation from the lower half of the distribution. This means that the assumption of a normal distribution does not hold. Nevertheless, the errors introduced by this assumption are likely to be relatively small, and are also likely to be less than the errors that would result from just using 90% POE, mean (50% POE), and 10% POE forecasts.

Table 18: Peak Demand Forecasts

	2.5% POE	10% POE EC High	20% POE	30% POE	40% POE	50% POE EC Mean	60% POE	70% POE	80% POE	90% POE EC Low
2006	2,088	2,063	2,047	2,035	2,024	2,015	2,004	1,992	1,978	1,958
2007	2,185	2,153	2,132	2,117	2,104	2,092	2,078	2,063	2,046	2,022
2008	2,286	2,246	2,220	2,202	2,186	2,171	2,154	2,136	2,115	2,086
2009	2,389	2,341	2,310	2,288	2,269	2,251	2,231	2,210	2,185	2,150
2010	2,492	2,435	2,398	2,372	2,349	2,328	2,305	2,280	2,251	2,211
2011	2,596	2,530	2,487	2,456	2,430	2,405	2,378	2,350	2,316	2,270
2012	2,700	2,624	2,575	2,540	2,509	2,481	2,451	2,419	2,381	2,329
2013	2,807	2,720	2,664	2,623	2,588	2,556	2,523	2,487	2,445	2,387
2014	2,912	2,815	2,752	2,707	2,668	2,632	2,595	2,555	2,508	2,443
2015	3,022	2,913	2,843	2,792	2,749	2,708	2,667	2,622	2,571	2,499
2016	3,126	3,008	2,931	2,876	2,829	2,785	2,740	2,691	2,635	2,556

Source: CRA calculations.

Table 19: Estimates of Unserved Energy (GWh), 70MW Interruptible Load

Forecast Probability	2.5% POE 5%	10% POE 10%	20% POE 10%	30% POE 10%	40% POE 10%	50% POE 10%	60% POE 10%	70% POE 10%	80% POE 10%	90% POE 10%	Expected Value
2009	-	-	-	-	-	-	-	-	-	-	-
2010	1.3	-	-	-	-	-	-	-	-	-	0.1
2011	14.4	4.2	1.0	0.1	-	-	-	-	-	-	1.2
2012	43.3	20.6	10.4	5.2	2.4	0.8	0.0	-	-	-	6.1
2013	90.8	50.8	31.5	20.4	12.8	7.4	3.5	1.0	0.0	-	17.3
2014	158.7	95.3	64.0	45.8	32.9	22.6	14.0	7.2	2.3	-	36.3

2015	261.1	159.6	111.2	82.9	62.4	46.3	32.4	20.3	9.7	1.7	65.7
2016	389.7	246.8	174.8	132.8	103.2	79.4	58.7	40.3	23.3	7.4	106.2

Source: CRA calculations. Years 2006-2008 are not presented because there is no unserved energy.

Table 20: Estimates of Unserved Energy (GWh), 200MW Interruptible Load

Forecast	2.5% POE	10% POE	20% POE	30% POE	40% POE	50% POE	60% POE	70% POE	80% POE	90% POE	Expected
Probability	5%	10%	10%	10%	10%	10%	10%	10%	10%	10%	Value
2009	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-	-
2011	0.3	-	-	-	-	-	-	-	-	-	0.0
2012	8.9	1.3	-	-	-	-	-	-	-	-	0.6
2013	33.6	12.4	4.3	1.3	0.1	-	-	-	-	-	3.5
2014	73.4	36.1	19.0	10.1	4.8	1.8	0.2	-	-	-	10.9
2015	134.8	73.9	45.3	29.2	18.2	10.3	4.6	1.3	-	-	25.0
2016	218.6	126.0	82.9	58.0	40.7	27.3	16.3	7.7	2.0	-	47.0

Source: CRA calculations. Years 2006-2008 are not presented because there is no unserved energy.