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Dear Alistair

TPM Working Paper: Problem definition

Genesis Energy Limited welcomes the opportunity to provide a cross-submission to the Electricity Authority ("the Authority") on the working paper "Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets" dated 16 September 2014 ("the Working Paper").

While any Transmission Pricing Methodology ("TPM") should deliver benefits to the average consumer, we suggest there are two key criteria the Authority needs to consider when establishing whether there is a problem and the future options that might overcome any problem:

- **Efficient Investment**. How does the TPM influence transmission, generation and demand-side investment decisions?
- **Efficient use of the grid**. What generator, consumer and demand-side behaviors does the TPM incentivise? Does it have negative impacts on utilization of the existing transmission assets?

Applying these criteria, we agree with the Authority that the current TPM is not perfect. In particular, it is clear that the current Historical Anytime Maximum Injection (HAMI) charge is not neutral to generators' operational decisions. Currently, the HAMI charge encourages South Island generators to holdback generation at times of peak demand at a cost to the wider market.

But we disagree with the Working Paper's assessment of the problems with the current transmission investment test. Proposed large capital expenditure on the grid will be tested by an objective framework administered by the Commerce Commission, and the TPM has little or no influence over this process.

Transpower is undertaking its own operational review to address most, but not all, of the problems identified with the current TPM. In particular, Transpower is investigating ways to remove or minimise the disincentive on South Island generators to generate at peak times. We strongly suggest that the Authority delay the release of the TPM options working paper to enable the recommendations from Transpower's operational review to be incorporated.

Elements of the problem definition

We agree with Authority's approach, signalled in the Working Paper, to align the problem definition and the subsequent cost benefit analyses of any proposed options. Implementing the focused approach suggested by the Authority in the Working Paper requires clear criteria for assessing the costs and benefits of any TPM but these requirements are still unclear. Although the Working Paper identifies two key elements, we suggest the elements can be further broken down into the following criteria to guide the Authority's assessment:

Figure 1 Criteria for TPM problem definition and assessment of options

Problem element	Criteria
Efficient Investment	TPM encourages efficient transmission investment decisions
	TPM encourages efficient generation investment decisions
	TPM encourages efficient demand-side investment decisions
Efficient use of the grid	TPM incentivises efficient consumers behaviour
	TPM incentivises efficient generator behaviour
	TPM leads to efficient utilisation of existing transmission assets

<u>Durability as a symptom of investment inefficiencies</u>

The Working Paper highlights poor durability of the TPM as a standalone problem. We suggest that "durability" is better considered as a symptom of investment inefficiency or inefficient use of the grid, i.e. the TPM will be durable if it avoids creating substantial inefficiencies. This approach to durability avoids the risk of double counting the benefits that would result from improving investment efficiency or improving the efficiency of grid use.

We also suggest that adaptability is a better description of the qualities that make a regulatory framework more durable. As the Authority itself has acknowledged, regulatory interventions in the electricity market have potentially long term impacts – which means that an adaptable approach is important. This is reflected in the Authority's preference for incremental regulatory change that minimizes the potential negative impact of changes, and ensures that changes can be relatively easily reversed if those changes are detrimental to the long-term benefit of consumers.

How are future investment decisions made?

Understanding the investment decision making process is critically important if the Authority is to improve investment efficiency. A participant will only participate in the investment decision making process if they have both the incentive and the ability to influence the outcome. While transmission investment decisions will directly affect the total costs allocated to market participants (and ultimately end-consumers), there is no direct link between the cost allocation decision and the investment approval decision. This, in our view, is the underlying issue that the Authority is trying to grasp. But we suggest the Authority has focused too much on the potential incentives for participants to provide information into the investment process, rather than looking to the investment decision process itself.

We suggest that there are two types of investment decision that can be influenced by the TPM:

- **Generation and Demand-side investment decisions.** Decisions made by market investors (boards of directors, individuals etc.) based upon a myriad of different factors. Our experience, as described in more detail in our assessment of the current TPM (below), is that transmission costs are a minor influence on investment decisions.

- **Transmission investment decisions.** The key decision makers here are Transpower and the Commerce Commission. Each entity is responsible for different parts of this decision making process: Transpower the formulation and execution; and the Commission approval. We suggest that it is important to examine the detail of this decision making process if we are to understand any underlying problem.

Figure 2 below, sets out the different jurisdictions, decision makers, and information flows relevant to transmission investment and the TPM.

Figure 2 Map of institutions and key decision points in transmission investment

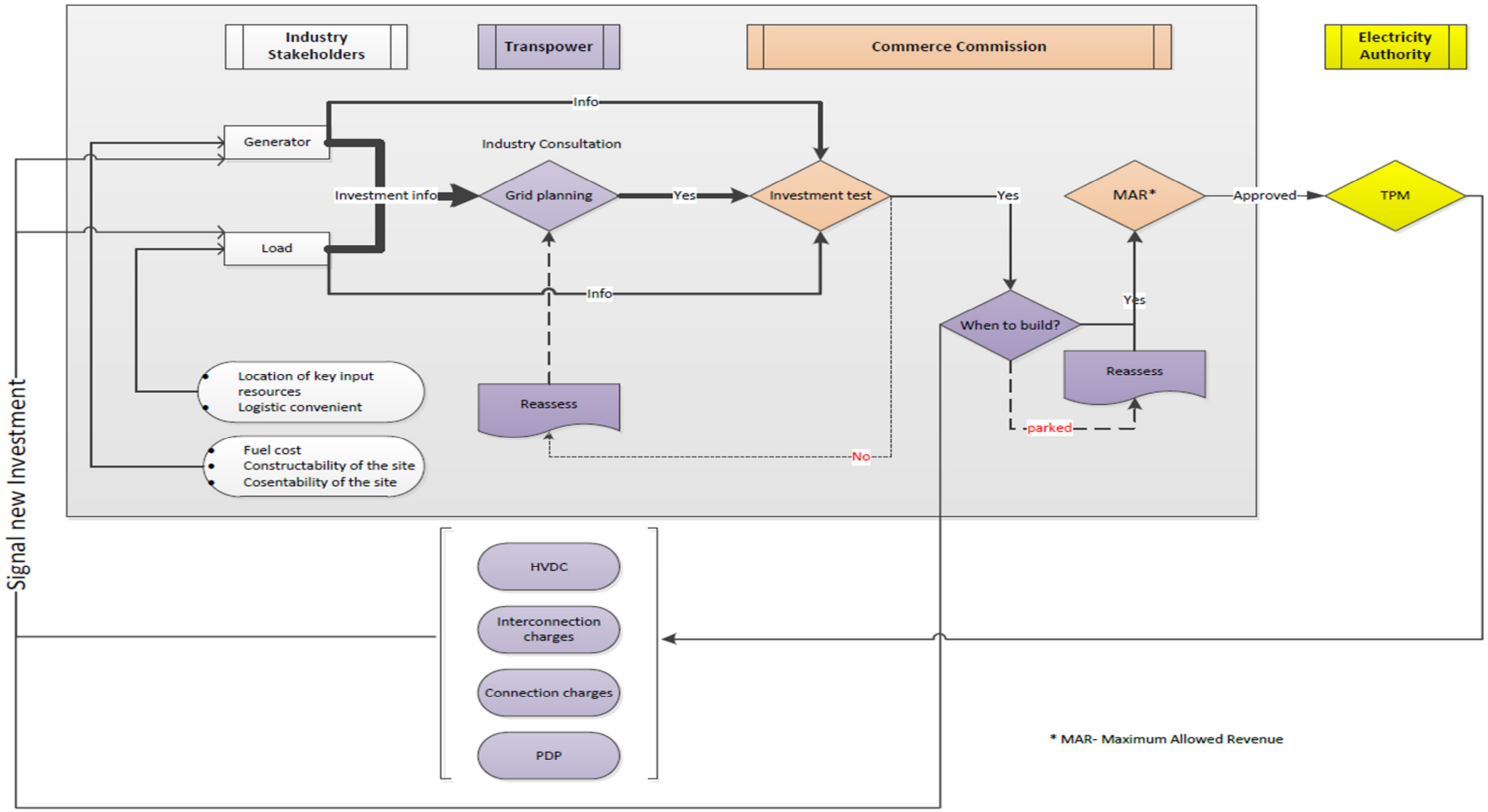

Figure 2 highlights the different jurisdictions that apply to different parts of the current transmission investment decision making process – including the TPM. The Commerce Act 1986 is the determining primary legislation governing any investment in new transmission assets. The Electricity Industry Participation Code 2010 applies to how Transpower allocates the recoverable cost of these investment decisions.

There are also different decision stages within the investment decision process that need to be considered. When considering these stages it is important to understand how information can be provided by market participants.

Figure 3 Transmission investment decision stages

Grid planning process (Transpower).	Annual process to determine the needs that the transmission system must meet, and the options for meeting those needs. Relies on information on future demand-side and generation investments. Also considers the efficiency of the existing grid.
Investment Test (Commerce Commission)	Regulatory process under the Commerce Act to approve Transpower's major capital expenditure. As illustrated by Appendix C to the Working Paper, anyone is able to provide information into the Investment Test via the Commerce Commissions decision process.
When to build (Transpower)	For some investment decisions, Transpower may seek greater discretion on the timing of a major investment. An example is the approved Clutha Upper Waitaki Lines Project. Whilst approved, Transpower has yet to formally commit to building this project.
MAR approval (Commerce Commission)	Sets the amount of revenue that Transpower is allowed to earn to recover all costs (capital costs, operating costs and tax). Formally reviewed every five years in accordance with Part 10 of the Commerce Act. Participants have the opportunity to provide submissions, as demonstrated by submissions on the current review of the MAR

TPM (Authority)	Interested parties, including generators and demand-side participants, are able to provide information into the review of the TPM guidelines and the TPM approval decision.

Our view is that the Authority's ability to influence the actual transmission investment decisions through the TPM is severely limited. The Authority has discretion over the establishment of how transmission costs are allocated and this could create an indirect incentive for participation in the transmission investment process. But it is important to acknowledge that the allocation of costs cannot directly influence transmission investment decisions. Different decisions ultimately require Transpower to propose a different set or timing of transmission investments, or for the Commerce Commission to adopt a different approach when deciding whether or not the investments should proceed.

How does the current TPM stack up?

We have focused on evaluating how the current TPM meets the problem definition criteria set out above. We requested Castalia to review the Working Paper, and particularly to assess the Authority's estimates of inefficiencies from the current TPM that relate to the operation of the market. Castalia's expert report is attached as Appendix A.

Castalia concludes that the inefficiencies estimated by the Authority are likely to overstate the size of any problems with the current TPM. As a result, the Authority's review of the TPM (together with Transpower's operational review) would most productively focus on making incremental improvements to the TPM, rather than radically redesigning transmission pricing arrangements.

Efficient Investment

Figure 4 Assessment of investment efficiencies with current TPM

Criteria	Current TPM
TPM encourages efficient transmission investment decisions	• Weak incentives to participate in investment decision process. • Investment Test is objective.

Criteria	Current TPM
TPM encourages efficient generation investment decisions	• Transmission cost are not influential on new generation or load decisions: • Already sufficient locational price signals for investment. • GIT test will identify and recommend investment to resolve this generator benefit.
TPM encourages efficient demand-side investment decisions	• Very few active participants in the market. • Most investment decisions are influenced by other factors – such as access to resources for a pulp-and paper mill.

Transmission investments

In our view, the current TPM has very little impact on the investment proposals made by Transpower, and the subsequent approval decisions made by the Commerce Commission. This is not surprising. Although the Authority retains most of the powers of the previous Electricity Commission, the approval of grid investments was deliberately split off and given to the Commerce Commission.

Figure 2 identifies the initial grid planning process and the Commerce Commission's investment test as the two key decision points for future transmission investment decisions. Both of these decisions are open and transparent, and information is often provided by industry participants (generators and demand-side) as well as modelled by Transpower. Despite the apparent lack of incentives to participate, the Authority has identified evidence of significant engagement by industry stakeholders[1] in the current investment process. We note that the record of submissions may be misleading as it does not make any assessment of the quality of the submissions provided, nor whether or not submitters engaged in the earlier Transpower run grid planning process.

[1] Appendix C of the Working Paper

This engagement demonstrates to Genesis Energy that the current system does enable information to be provided to Transpower, and the Commerce Commission, for them to make informed decisions on transmission investment needs.

Figure 2 also shows that the jurisdictions and decision makers are separate. Transpower and the Commerce Commission have processes that are designed to provide an objective assessment of transmission investment needs. The two stage approach (planning and approval) is, in our view, a safeguard intended to ensure that Transpower maintains this objectivity. We have no reason to question the Commission's objectivity in this regard. This objectivity is important, as further engagement in the transmission investment process by market participants will only eventuate if there is both an incentive and an ability to influence. The Authority has not demonstrated what new information generators or consumers will be able to provide into the transmission investment process that is not already available, and in some cases, already provided by those same participants.

Generation investments

Generation investment decisions depend upon a broad range of factors at different stages of the investment decision making process. Primary consideration will be the fuel cost (or access to renewable fuel), constructability and consentability of the site. Direct transmission charges may have some impact, but we suggest that interconnection and HVDC charges will have a minor impact (if any) on the overall decision.

A more relevant, and related, price signal is the existing nodal price based signals including spot price, ASX futures prices, as well as potential FTR prices. Together, this range of market prices provides investors with strong locational price signals. Importantly, these prices will generally signal historical constraints and periods (investors will face uncertain future prices).

Transmission charges will only influence the most marginal generation investment decisions. However, even where new generation obtains a benefit from the grid it is likely to only be a short term benefit. We suggest the Investment Test will identify and recommend investment to resolve areas where generators benefit the most from any transmission constraints over time. In addition, as identified in Castalia's analysis, new generation capacity is more likely to be built in the North Island.

Demand-side investments

Similarly, for demand-side investment, it is more important for most businesses to consider resource[2] locations rather than transmission cost allocations. The materiality of transmission charges will depend on its proportion to their total business cost. Although the current TPM can impose sharp transmission pricing signals through RCPD, in reality, only a small number of intensive energy consuming industries have chosen to actively manage this risk. This leads us to a view that, for most businesses, transmission charges are not material.

Efficient use of the grid

Genesis Energy agrees with the Authority that the current TPM (certainly the current application of the current TPM) creates inefficiencies. Ideally, we suggest that allocation of the cost of interconnection assets will be neutral to participants operational decisions post investment. This is because there are already established pricing signals that provide market participants with incentives to change their behaviour in reaction to grid constraints. Any allocation mechanism that seeks to incentivise certain behaviour risks adding unnecessary complexity into the market, and may distort existing price signals.

Figure 5 Assessment of operational inefficiencies with current TPM

Criteria	Current TPM
TPM incentivises efficient consumers behaviour	• No clear need for RCPD signals after transmission investment has been completed. RCPD confuses existing market signals. • Distributors are likely to continue demand-side management for own asset management purposes.

[2] For example key inputs may include raw materials, natural resources, and labour

Criteria	Current TPM
TPM incentivises efficient generator behaviour	• Current HAMI incentivises South Island generators to withhold generation from peak periods. • Little (if any) realistic impact on future South Island generation investment given recent transmission upgrades, the suite of North Island generation options available, and declining demand growth. • Some South Island generators incentivised to advocate for change to allocation mechanism due to equity concerns.
TPM leads to efficient utilisation of existing transmission assets	• Reduced insofar as the HAMI and RCPD cause inefficient use of the grid (i.e. over-signalling reduces demand even when spare transmission capacity exists).

The Castalia expert report attached at Appendix A to this document includes more detail on the assessment of current operational inefficiencies.

We agree that the current HAMI disinentivises South Island generators from providing capacity during periods of peak demand. Transpower's recent work on this aspect of the problem may address the $12 million (present value) inefficiency.

Transpower's Operational Review

We have also considered the options from Transpower's operational review of the TPM against the same criteria. We suggest this is a useful comparison as both approaches are within the constraints of the current TPM guidelines.

<u>Efficient investment</u>

In our view Transpower has the ability to consider other processes that may, in conjunction with the operational review of the current TPM, improve investment decisions. In particular, we suggest that Transpower could:

- Together with the Commerce Commission, consider whether the decision when to build an approved investment can be made more transparent with wider opportunity for stakeholder input; and

- Together with the Authority, formalize the operational review process as part of the TPM guidelines. This will ensure that the TPM is fit for purpose and reflects changing market circumstances.

A broader review of the Commerce Commission investment test criteria is also an option that has the potential to deliver tangible improvements to the transmission investment decision process. We understand that this will happen as part of the formal review of all input methodologies scheduled for 2017.

<u>Efficient use of the Grid</u>

Figure 6 Assessment of operational inefficiencies after Transpower's operational review

Criteria	Operational Review
TPM incentivises efficient consumers behaviour	• Increasing number of peaks may reduce confusion between RCPD and other market signals (such as demand-side participation).
TPM incentivises efficient generator behaviour	• Increasing number of peak injection periods or moving to a per MWh charge will remove the current disincentive on peak generation by South Island Generators. • Some South Island generators incentivised to advocate for change to allocation mechanism.
TPM leads to efficient utilisation of existing transmission assets	• By changing the HAMI and RCPD to neutral price signals the review will reduce, or eliminate, any utilisation inefficiency's.

Transpower's operational review of the current TPM will address most, if not all, of the market operation inefficiencies identified by the Authority. The remaining residual operational inefficiencies will be, in our view and as validated by

Castalia's analysis, minimal. We suggest these residual efficiency problems will only support an incremental approach to TPM improvement.

Where to from here?

We strongly suggest that the Authority delay the release of their TPM options working paper to enable any recommendations from Transpower's operational review to be incorporated.

In our view, the Working Paper identifies a fundamental concern with how new transmission assets are approved. If this is a problem, it cannot be addressed by changes to the current TPM alone. We suggest that the sector's resources will be better applied looking for incremental solutions that address problems in the current transmission investment process. We are optimistic that this Working Paper and the on-going Transpower Operational review will lead to such an option being developed by the Authority.

If you would like to discuss any of these matters further, please contact Jeremy on 04 495 3340.

Yours sincerely

Jeremy Stevenson-Wright
Regulatory Affairs Manager

genesis ENERGY

Appendix A: Castalia expert report

Transmission Pricing, Market Operations, and Investment Decisions:

A Review of the Electricity Authority Problem Definition Working Paper

Report to Genesis Energy

October 2014

Acronyms and Abbreviations

the Authority	The Electricity Authority
the Commission	The Commerce Commission
EDB	Electricity Distribution Business
GEM	Generation Expansion Model
HAMI	Historical Anytime Maximum Injection
HVDC	High-Voltage Direct Current (transmission link between the North and South Islands)
LNI	Lower North Island RCPD region
LRMC	Long-Run Marginal Cost
LSI	Lower South Island RCPD region
MBIE	Ministry for Business Innovation and Employment
MW/MWh	Megawatt/Megawatt hour
PDP	Prudent Discount Policy
PJM	Pennsylvania-New Jersey-Maryland Regional Transmission Organization
PV	Present Value, or value discounted to today's terms
RCPD	Regional Coincident Peak Demand
SRMC	Short-Run Marginal Cost
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
UNI	Upper North Island RCPD region
USI	Upper South Island RCPD region
vSPD	vectorised Scheduling, Pricing and Dispatch

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Executive Summary

As part of its Transmission Pricing Methodology (TPM) review, the Electricity Authority (the Authority) has released a working paper that defines a series of problems with the current interconnection and High-Voltage Direct Current (HVDC) charges. In its working paper, the Authority expresses the view that the current TPM does not promote efficient transmission investment, is not durable, and fails to promote efficient operation of the electricity industry. The Authority quantifies many of the problems that it identifies, with the combined size of these inefficiencies estimated to fall between $115 million and $291 million in present value terms.

Genesis Energy has engaged Castalia to review the Authority's working paper and comment on the inefficiencies identified by the Authority. In particular, we have considered whether the current TPM creates inefficiencies in market investment and operational decisions. We consider that the high fixed costs of electricity transmission make some level of inefficiency inevitable. We find that the inefficiencies estimated by the Authority, while relatively minor, are materially overstated because they are derived from multiple sources (not just the TPM). The size of any problems with the TPM strongly suggests that the Authority's TPM review should focus on identifying incremental improvements, rather than radically redesigning transmission pricing arrangements.

No TPM will be perfect given the high fixed costs that need to be recovered

Problems with the current TPM need to be interpreted in light of the fact that no transmission pricing system is perfect (as stressed by the Authority on several occasions). The reason that transmission pricing cannot be perfectly efficient is that substantial fixed costs need to be recovered. While efficiency calls for marginal cost pricing (with pricing reflecting the level of spare capacity or need for new investment), fixed cost recovery is likely to require some customers to face prices higher than marginal cost. It would be entirely coincidental and very surprising if a set of purely efficient prices allowed Transpower to earn its Maximum Allowable Revenue and no more. Transpower's investment programme over recent decades has been quite cyclical, resulting in greater excess transmission capacity in some years, contrasting with greater investment needs in others.

Resolving the tension between efficient marginal cost prices and practically achievable average cost prices is the core challenge examined in this paper.

In this context, inefficiencies with the current TPM appear relatively small

Given the difficulty of recovering Transpower's required revenues through efficient prices, the current TPM appears to perform remarkably well. That is not to say that more efficient prices are not possible and should not be sought. However, it is clear that the actual size of the problems identified by the Authority does not justify a radical change. Rather it suggests that incremental improvements should be the aim, rather than radical redesign. As context, total inefficiencies are a fraction of the underlying assets the TPM recovers and small relative to other areas such as the potential annual benefits from consumer switching.

Several previous attempts at TPM problem definition have also found relatively small inefficiencies. This is because prices are likely to be above short-run marginal cost for the vast majority of transmission customers, and as a result very few customers are being cross-subsidised. While some customers face a price of zero for the use of some assets (such as the HVDC link), the short-run marginal cost of additional use of the HVDC link will be close to zero. Meanwhile, the cost of the assets still needs to be recovered, implying different rates of fixed cost recovery from different users (which may not be inefficient).

However, the Working Paper overstates problems with the current TPM

Even though the problems identified by the Authority are relatively small, we have closely examined the Authority's estimates to test their validity. By adopting different (and we believe more appropriate) analytical approaches to quantify the impacts identified by the Authority, we find that the size of any problems with the current TPM is likely to be smaller than estimated by the Authority. We find that the inefficiencies in interconnection and HVDC charges create efficiency losses of around $4 million to $101 million in present value terms. This is materially lower than the Authority's estimates. As such, we provide a detailed comparison of the estimates and explain the basis for our revised estimate below (we are also happy to make our detailed calculations available to the Authority, if requested).

The reasons the Authority's estimates overstate the size of the problems are:

- **The role of other parties and processes has been overlooked.** Transpower and the Commerce Commission (the Commission) have significant influence on transmission investment and pricing decisions, and have the direct means to address some of the problems identified (such as through Transpower's current operational review). By ignoring the division of institutional responsibilities the Authority's analysis overstates the problems with the current TPM.
- **Some of the market inefficiencies identified by the Authority are not caused by the TPM.** The way that the Authority has estimated inefficiencies with the current TPM ascribes a value to impacts that have some relationship or dependency with the TPM. A more targeted analytical approach would only classify impacts as a problem with the TPM if changes to the TPM could resolve the problem. By adopting this analytical philosophy, we find that the inefficiencies in market operations are less than half of the size estimated by the Authority (present value $4 million to $101 million, rather than $35 million to $211 million).
- **The claim that the current TPM lacks durability is not credible.** Despite strong negative feedback on this area of claimed inefficiency, the Authority continues to assert that a lack of durability in the current TPM creates a net cost. This claim is particularly weak given the inherent difficulty in determining efficient and fair transmission prices and the relatively small size of other problems identified by Authority. In reality, all regulatory processes create winners and losers, and therefore have some amount of disagreement in them. The current TPM has remained in place for a reasonable period of time, and has the flexibility to accommodate operational reviews (like the one Transpower is currently undertaking). In light of these facts, the Authority's insistence on retaining a separate durability problem defies reason.

Our analysis quantifies the inefficiencies identified by the Authority, allowing for the above factors. Table ES.1 summarises our results and compares them with the Authority's analysis according to the categories of inefficiencies used by the Authority (which differ from those used in Genesis Energy's submission).

Table ES.1: Revised Analysis of the Scale of TPM Inefficiencies (millions)

Element		Authority Analysis	Castalia Analysis
RCPD	Over-signalling the need for load shedding during peak periods	$11 benefit –$96 cost	$4 benefit – $18 cost
	Over-signalling the need for overall reductions in consumption	$3-$40	$0-$30
	Over-signalling the cost of increasing Tiwai smelter's summer production	$4-$32	$4-$32
HVDC	Incentivising South Island generators to withhold existing capacity	$12	$0-$12 (generation investment)
	Discouraging upgrades or new investment in South Island generation	$25	$4-$9 (generation investment)
	Bringing forward the need for upper South Island transmission investment	$2-$6	$0
Total Inefficient Market Operation		$35-$211	$4-$101
Inefficient Transmission Investment		$43.5 (illustrative only)	$0*
Poor durability		$36.5	$0*
Total		**$115-$291**	**$4-$101**

* Our analysis follows the Authority's characterisation, incorporating inefficiencies in generation investment as relating to market operations when considering the impact of RCPD and HVDC charges. To avoid double-counting we exclude these impacts from the figure for inefficient investment. See Genesis Energy's submission for further discussion of these elements.

Source: Castalia analysis of Electricity Authority "Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets.

The problem definition establishes appropriate methods to assess options and an upper bound to potential benefits

In response to the feedback on the October 2012 issues paper and the cost benefit analysis working paper, the Authority has acknowledged the importance of aligning the problem definition with cost benefit analyses of possible changes to the TPM. We agree that the cost benefit analysis (CBA) should focus on assessing how any of the options being tested would resolve the inefficiencies identified with the current TPM, while minimising the impact of any new inefficiencies or costs. Only through this analysis can the Authority build confidence that any proposed changes achieve its statutory objective.

The problem definition working paper adopts a "bottom up" analytical approach, stepping through a series of individual efficiency effects and aggregating them into an overall impact. We agree that this is the best way to scope out the nature and size of problems with the current TPM, and have consistently argued that it is also the most credible way to carry out a CBA on any proposed changes to the TPM.

We support the Authority's intention, and recommend the following ways to achieve a desirable level of coherence between the problem definition and CBA:

- **Identify elements of the problem that are separable.** In this report, we suggest considering transmission pricing for the Tiwai Point aluminium smelter separately from other problems. There may be other elements of the problem that are distinct. Separating out distinct elements of the problem allows solutions to be tailored to specific problems, and potentially enables different solutions to be combined to address several problems.
- **Evaluate options using the same analytical approaches applied in the adjusted problem definition.** For example, in its working paper the Authority evaluates inefficiencies arising from RCPD charges in failing to equate prices with costs. The same analysis can and should be done for alternative charging approaches, such as the SPD charge previously proposed by the Authority. Ensuring the same level of analytical rigour in the problem definition and CBA will help to build confidence in any proposed changes.
- **Using the problem definition as the upper bound for the net benefit of any change.** If changes to the TPM are designed to resolve current inefficiencies, then we would expect the net benefit of any options to be lower than the problems identified (that is solutions will resolve a substantial part of any problems, but no more). While it is conceivable that changing the TPM may bring additional benefits in areas not considered to be problems with the current TPM, to be credible any such effects will need to be clearly identified and estimated.

1 Introduction and Background

The Authority has released a problem definition working paper as part of Transmission Pricing Methodology (TPM) review. The working paper restates previous problems asserted by the Authority, extends the problem definition in some areas, and attempts to quantify what it sees as the inefficiencies of the current TPM.

Genesis Energy has asked Castalia to comment on the potential impacts of the interconnection and HVDC charges on market operational efficiency. This report examines these aspects of the Authority's working paper, examining the Authority's analytical approach, key assumptions, and overall quantification. The report suggests possible improvements to some of the analysis, re-calculating the size of the inefficiency (where material).

This report also examines whether the problems identified by the Authority would be solved by changing the TPM. The TPM exists within a set of arrangements that control pricing and investment decisions in the electricity sector—including the Investment Test, distribution pricing, and Transpower's operational control of transmission pricing.

This section summarises the three broad problems with the TPM as identified by the Authority, and describes the role of the Authority and other parties in transmission investments and revenue recovery.

1.1 The Authority has Identified Three Broad Problems

Three broad problems with the TPM at present are identified by the Authority:

- **Inefficient investment.** Current transmission prices place insufficient incentives for parties to get involved in decisions to invest in new transmission, and as a result investment outcomes are likely to be suboptimal. The Authority does not directly estimate this problem, but provides an illustrative example that would lead to a cost of $43.5 million in present value terms. We envisage the Authority will likely undertake further work to estimate the scale of this issue before releasing the second issues paper. However, we have simply incorporated the Authority's illustrative figure when reporting the Authority's aggregated estimate of problem size in this paper.
- **Poor durability.** The current TPM creates incentives to lobby for change, and the use of resources for lobbying is not productive. The Authority estimates the scale of this inefficiency to be $36.5 million in present value terms.
- **Inefficient market operation.** The interconnection and HVDC charges create the wrong signals for using the grid, and investing in generation and load to alter use of the grid. In aggregate, the Authority estimate the scale of this problem to fall somewhere between $35 million and $211 million in present value (which is quite a large range).

This suggests the size of inefficiencies created by the current TPM total $115 million to $291 million in present value (including the illustrative effect of inefficient investment). For the transmission network in New Zealand, this is a relatively small problem. For example, Transpower's regulatory asset base (the assets being priced) is around $3 billion.[1] So this suggests inefficiencies are a small proportion of the value of the assets being recovered. It also compares with *annual* savings of around $267 million if all consumers switched to the cheapest retailer in their region.[2]

This report focuses on the third broad problem identified by the Authority: inefficient market operation. This accounts for most of the inefficiency quantified by the Authority and is also (in our view) the most credible problem articulated by the Authority. The other problems identified by the Authority (inefficient transmission investment and durability) are in our view less credible as there is:

- **No evidence information is withheld from transmission investment decisions.** It is far from clear that market participants have any information that is not currently available to Transpower and the Commission in proposing and approving regulated transmission investments. To credibly establish an efficiency loss, the Authority would need to highlight how future investment decisions would be different if participants face stronger incentives through prices to participate in the decision-making process.
- **No evidence that industry engagement has been detrimental or that changes would remove any disagreements.** The problem of a lack of durability and an inefficient use of resources in debating the TPM lacks merit. There is no evidence that the amount of time, energy, and disputation over the current TPM has been inefficient. While the current settings are contrary to some participants' interests, that is true of a multitude of other regulatory processes and decisions.

1.2 Need to Identify Problems that Relate to Transmission Pricing Guidelines

In determining the nature of any problems (and whether they stem from the TPM guidelines), the Authority's analysis must account for:

- How the TPM interacts with other processes, and
- The TPM's influence on decision making.

The TPM, and the Authority's responsibility for the TPM guidelines, operate alongside other mechanisms. Together, these mechanisms aim to ensure efficient pricing, operation, and investment decisions in the electricity sector.

A problem only relates to the TPM if it can be resolved by a change to the TPM

The TPM exists within a set of arrangements that control pricing and investment decisions in the electricity sector. Genesis Energy's submission helpfully maps out the key relationships relevant to transmission investment decisions. When considering problems with the TPM, we need to distinguish between problems that are TPM problems at their core, and problems that have some relationship or dependency with the TPM.

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1 Transpower's Annual Planning Report 2012/13 (latest currently available) reports an opening RAB of $2.8 billion and a projected closing RAB (or opening RAB plus weighted commissioned assets) of $3.4 billion. See: https://www.transpower.co.nz/sites/default/files/publications/resources/annual-regulatory-report-2012-13_0.pdf

2 Source: Electricity Authority "What's My Number: Competition and choice – a review of the 2013 campaign", available at: https://www.ea.govt.nz/consumers/whats-my-number/annual-review/

This paper proposes a way to define problems with the TPM that is narrower than the approach adopted in the Authority's working paper. We suggest that something should only be classified as a problem with the TPM if changes to the TPM could possibly resolve the problem. If a source of inefficiency exists that would remain even if the TPM was changed (in whatever way), then the inefficiency should not be classified as a problem with the TPM.

We see three key benefits to adopting this narrower concept of TPM problems in the current review:

- **Progression:** It helps to ensure that whatever comes out of the TPM review actually improves the efficiency of the sector. If changes are made to the TPM that do not lead to efficiency gains, then the Authority's statutory mandate is not being advanced
- **Tractability:** It appropriately manages expectations from the TPM review. Stakeholders will be holding the sector to account to deliver the promised efficiency gains
- **Targeting:** It helps to create lasting solutions and direct efforts where they need to be focused, rather than opening up more avenues of reform. If changing the TPM simply highlights that further changes (such as to the Investment Test or distribution pricing) are needed, this would be unsatisfactory—particularly if it is possible to directly address any weaknesses in those other areas.

Several problems relate to the operation of the TPM, rather than the guidelines

To properly understand existing problems, it is important to accurately characterise the roles and responsibilities of a number of different parties and processes. Genesis Energy's submission discusses the roles of Transpower and the Commission, in particular. Transpower owns and maintains the transmission grid and operationalises the TPM. Meanwhile, the Commission approves major investments and regulates the recovery of costs relating to Transpower's regulated activities. Other regulated processes (such as distribution pricing) also affect how the costs of transmission are recovered from electricity consumers, as discussed in later sections of this report.

Transpower's review responds to various issues identified with the current TPM. Transpower's role in transmission pricing is particularly relevant to the focus on problems with the TPM Guidelines. Transpower is currently reviewing the operation of the TPM, aiming to identify solutions that could be made within the current TPM guidelines.

Transpower has released an update paper (and subsequent analysis) having received submissions on its initial consultation paper.[3] Following further consultation, Transpower intends to propose any TPM amendments to the Authority in February 2015 in order for:

- The Authority to make a decision on the proposal, given the Authority's role in approving that the proposed TPM is consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010, and
- Transpower to make any operational changes necessary for the amended TPM to be applied to the Capacity Measurement Period starting September 2015.

[3] See: https://www.transpower.co.nz/about-us/industry-information/tpm-development

Transpower's review identifies a number of the same problems as the Authority's working paper, and Transpower has suggested potential solutions that it intends to investigate further. The issues with the most overlap are shown in Table 1.1.

Table 1.1: Problems Transpower Intends Addressing in its Operational Review

Potential Problems	Possible solutions
Having completed investments that enhance capacity into the Upper North Island (UNI) region, the existing pricing signals (designed to signal future investment need) may be inefficient.	Transpower proposes further analysis on these issues and to investigate options such as 'detuning' the UNI (by increasing the number of RCPD peaks) and reviewing the definition of RCPD regions i.e. Transpower proposes to consider combining UNI, LNI, and LSI into a single region.
It appears that some Lower North Island (LNI) direct-connect customers respond to RCPD by reducing their contribution to regional peak demand. There is also a history of unstable pricing signals in the Lower South Island (LSI) region given the size of the Tiwai smelter relative to regional demand. In addition, LSI peak demand is not a driver for transmission investment in the region.	
Successive reviews have identified problems with Historical Anytime Maximum Injection (HAMI) as an allocator for HVDC charges.	Transpower proposes to consider changing to an energy (MWh) allocator for HVDC charges, an 'incentive-free' charging option or a HAMI charge based on multiple peaks.

Source: Figure 2 of "Transpower TPM Operational Review: Initial Consultation Paper", 9 July 2014

Transpower's parallel process creates some difficulty in defining problems in the Authority's review. The Authority clearly cannot just assume that any problems identified by Transpower will be effectively resolved through the operational review. At the same time, ignoring the operational review entirely risks identifying problems that may soon be resolved.

The approach that we take in this paper is to first consider the problem as it stands today. We then identify whether it relates to the TPM and, if so, how Transpower's operational review might affect the nature and size of any problems.

Perhaps the more important point raised by the overlap in reviews is the need to draw a clear line between the regulatory responsibilities of the Authority and Transpower. These roles are summarised in Box 1.1.

Box 1.1: TPM Responsibilities: The Authority and Transpower

The Authority sets the overarching TPM guidelines, and the TPM must be designed within those guidelines. The Authority then approves the final design of the TPM if it is consistent with its objective of promoting competition in, reliable supply by, and efficient operation of, the electricity industry. This fits with the Authority's responsibility for developing, administering and enforcing the Electricity Industry Participation Code.

Meanwhile, Transpower is responsible for the design and operation of the TPM. This is consistent with Transpower commercial responsibilities to allocate charges to its customers in a way that recovers the cost of services it provides to them (including a risk-adjusted return on capital).

Source: The Electricity Industry Act 2010 and Electricity Industry Participation Code, and analysis of these in "Transpower TPM Operational Review: Initial Consultation Paper" and on the Electricity Authority's website

1.3 Structure of this Report

This report reviews the important concepts that underpin the efficiency of transmission pricing, before examining specific concerns identified by the Authority regarding the current interconnection and HVDC charges.

The remainder of this report proceeds by:

- Describing concepts that are important for efficient transmission pricing (Section 2)
- Reviewing the estimated inefficiencies in market operations identified by the Authority, resulting from:
  - Interconnection charges (Section 3), and
  - HVDC charges (Section 4)
- Summarising the implications of our analysis of the problem for the Authority's TPM review (Section 5).

We are happy to make our detailed calculations available to the Authority if requested.

2 Important Concepts for Efficient Transmission Pricing

This section discusses two high-level concepts that are important for efficient transmission pricing: cost-reflective pricing and optimal investment decision-making. It is important to be clear on these concepts before identifying, describing, and quantifying specific problems.

Prices that are aligned with marginal costs promote efficiency

The Authority's working paper anchors all three broad problem areas (efficient investment, durability, and efficient operation) on the concept of cost-reflective pricing. This concept is illustrated in Figure 1 of the Authority's working paper.

We agree that having prices that are broadly in-line with the costs of service provision is an appropriate objective. This generally promotes efficiency because prices signal to users the costs of their consumption decisions—meaning that transmission services should only be used when the benefits to users outweigh those costs.

However, the presence of substantial fixed costs complicates this objective and means that the Authority needs to be precise about the cost concept that is used. In its working paper, the Authority uses the "cost of meeting demand" in a high-level way, without specifying whether it is concerned about deviations between price and short-run or long-run costs, or marginal or average costs. This makes it very difficult to connect the over-arching problem of a lack of cost-reflective pricing with specific problems identified with the current TPM (as examined in Sections 3 and 4 of this report).

Conventional infrastructure economics[4] provides four specific ways to express "cost":

- **Stand-alone cost**: The lowest cost way to provide dedicated transmission services to each customer (at an equivalent or a higher-level of service). This may be through an alternative (non-network) solution, such as a diesel generator, or through dedicated transmission assets. The stand-alone cost should generally be higher than the price as otherwise there is likely to be a case for a prudent discount (of which there are three at present).[5]

- **Short run marginal cost** (also known as incremental cost): The cost of operating and maintaining transmission assets to provide an additional unit of electricity to each customer. This cost benchmark does not include the fixed cost of building shared network assets or the cost of connecting each customer. The "but for" pricing used by the Pennsylvania-New Jersey Maryland Regional Transmission Organisation (PJM) referred to by the Authority appears to be an example of short-run marginal cost pricing.

- **Long-run average cost**: The total costs of providing the service per unit of demand. This cost benchmark is calculated by adding together all lifetime fixed and variable costs and then dividing by lifetime usage. This cost concept appears to best reflect what the Authority shows in Figure 1 of its working paper—which reflects the annual cost, including a return on capital and

[4] See, for example, "Microeconomics", Fourth Edition, by David Besanko and Ronald R. Braeutigam

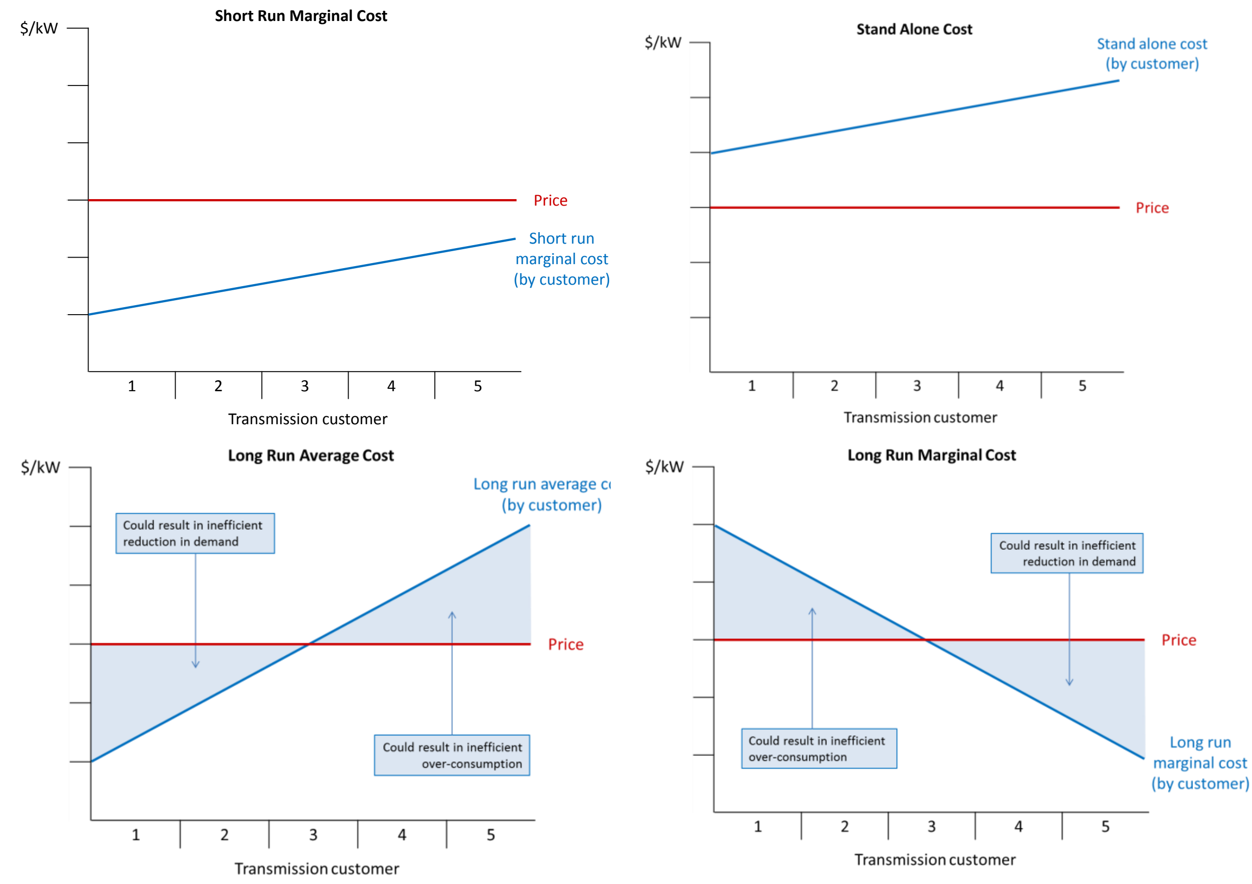
[5] See: https://www.transpower.co.nz/about-us/industry-information/revenue-and-pricing

operational costs of providing transmission services. This is a similar benchmark to Transpower's annual revenue requirement from each customer.

- **Long run marginal cost**: The costs of serving an additional unit of demand, including the fixed costs of expanding network capacity.

These four cost concepts are illustrated in Figure 2.1.

Figure 2.1: The Application of Different Cost Concepts to Transmission Pricing



At a high level, efficient transmission prices would involve:

- **Low prices in areas with spare transmission capacity** (prices close to short-run marginal cost). These low prices would encourage greater asset utilisation in parts of the grid that have no approaching investment needs—ensuring that maximum benefit can be derived from use of the grid, without bringing forward the costs of new investment

- **High prices in areas approaching the need for new investment** (prices close to long-run marginal cost). These high prices would encourage use of the grid only when it is more efficient than other ways to serve demand, such as locating generation close to load or investing in demand response capability. These high prices would contribute towards the goal of serving electricity demand at the lowest supply chain cost.

It would be entirely coincidental and very surprising if a set of purely efficient prices allowed Transpower to earn its Maximum Allowable Revenue and no more. As a result, prices that allow Transpower's to recover its costs will create some inefficiency.

Sections 3 and 4 of this paper examine the inefficiencies with the current interconnection and HVDC charges, applying the cost concepts discussed in this section. For example, we consider the additional charges (or price) Tiwai would face if it expanded its demand in summer months and compare these with the negligible marginal cost (both short-run and long-run) of transmission that would result from this additional demand. The same cost and price issues (and concepts) are also relevant to an analysis of RCPD signals to the demand-side operations and HVDC signalling to generators with existing capacity.

Optimal electricity sector investment requires coordination between market and regulatory processes

While the Authority's paper focuses on the relationship between cost and price as the source of TPM problems, in our view the inherent challenge of coordinating an optimal set of investments in the electricity sector is also relevant.

It should be uncontroversial to say that the long-term interest of consumers will be best served when electricity demand can be reliably met from the lowest cost combination of generation, transmission, distribution and demand-response capability. However, achieving this optimised set of investments is extremely difficult for many reasons. Of particular relevance to the Authority's working paper, generation and demand-response investments are primarily carried out in response to market signals (nodal prices), while transmission investment and pricing is regulated (as is distribution).

Assuming that market signals are broadly efficient (or that any inefficiency in nodal prices and demand-response capability would be solved through a different workstream), regulated transmission investment and pricing decisions could create inefficiencies if they:

- **Distort market-based investment decisions**. For example, if parties investing in generation or demand-response were reluctant to do so on the basis of market prices because investors perceive a risk that regulated investment may change the future returns their investment earns. Alternatively, if transmission pricing approaches changed market-driven investments that would not increase transmission costs
- **Ignore cheaper market-based investment options**. For example, if regulated investments fail to identify where generation or demand-response would provide a lower cost solution than transmission.

This concept of optimal investment is relevant to both interconnection and HVDC charges. If interconnection charges lead consumers to reduce their load (or decide not to invest to expand their load) despite not causing an associated transmission cost (zero cost in the graphs in Figure 2.1), then outcomes will be inefficient. In the same way, if HVDC charges cause generators to defer investment or locate it in higher cost areas, then this does not serve the long-term interests of consumers.

3 Interconnection Charges

The Authority's paper suggests that problems with interconnection charges may account for the majority of overalls problem with the TPM. This section examines each of the problems resulting from interconnection charges that are quantified by the Authority. We start by providing an overview of the identified problems and their quantified scale. We then analyse the extent that each problem may be addressed within the current framework or by changes outside the TPM, and suggest improvements in quantifying each problem.

The Authority identifies five problems with the interconnection charge

The Authority considers that the RCPD allocation for the interconnection charge may over-signal the:

- Need for load shedding at peak times, resulting in either:
  - Inefficient load shedding at peak times, or
  - Inefficient overall reductions in electricity consumption for those that do not face peak signals directly, or are unable to respond during peaks
- Cost of increasing Tiwai smelter's production in the summer months
- Value of embedded generation (which the Authority is still considering)
- Value of generation to direct-connect consumers (where the Authority notes any efficiency loss is unlikely to materialise and is likely to be immaterial).

The Authority quantifies all but the last two of these inefficiencies. Our analysis below focuses on the problems that the Authority has quantified and which make a material difference to the overall estimated size of the inefficiency.

Only a subset of these issues relate to the overall TPM design

Table 3.1 summarises our approach to the problems quantified by the Authority. We find that the inefficiencies relating to current RCPD charges amount to between a benefit of $4 million and a cost of $80 million in present value terms (of which $0 to $62 million of cost relates to inefficiencies associated with the Tiwai smelter). This contrasts with the $4 million benefit to $168 million cost range identified in the Authority's paper. The remainder of this section examines the issues identifies in Table 3.1 in greater detail.

Table 3.1: Reframing the Problems Identified with Interconnection Charges

Inefficiency	Authority's evaluation	Authority's estimation	Elements overlooked in the evaluation	How our analysis incorporates these elements	Adjusted estimation
Over-signalling the need for load shedding during peak periods	Peak signal leads to greater costs than benefits (avoided investment)	PV$11M benefit-$96M cost	▪ There are multiple reasons for EDBs and direct connects to control load ▪ EDBs have no direct financial interest in transmission charges	Incorporates the impact of: ▪ EDBs controlling load for distribution capex deferral ▪ Direct connects avoiding the spot price on reduced peak load	PV$4M benefit-$18M cost
Over-signalling the need for overall reductions in consumption	An overall reduction in consumption results from RCPD charges being variabilised, or direct connects not responding. This is inefficient if the transmission price is greater than the marginal cost of transmission	PV$3M-$40M	Distribution pricing allocates transmission costs to different consumer groups. This may not be a problem if Ramsey pricing is used.	▪ Removes large direct connected industrial load ▪ Analyses the link with distribution pricing for mass market consumers	At most PV$0M-$30M (likely to be less)
Over-signalling the cost of increasing Tiwai's production in the summer months	LSI RCPD charges disincentivise Tiwai to run during the summer months despite ample transmission capacity	PV$4M-$32M	Could be resolved through: ▪ Transpower's review ▪ Making PDP arrangements more flexible	Solutions should reflect that this is an issue singular to Tiwai, rather than TPM arrangements for all customers	Less than PV$4M-$32M if addressed in Transpower review, or $0 if addressed by a non-TPM agreement
Total		**PV $4M benefit-$168M cost**			**Excl.Tiwai: PV$4M benefit-$18M cost** **Tiwai: PV$0-$62M**

Source: Castalia analysis of Electricity Authority "Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets".

3.1 RCPD Over-signals the Need for Peak Load Shedding

Although the RCPD allocation is intended to incentivise load shedding during peak periods, the Authority is concerned that this is creating an inefficiency where some EDBs and direct-connect customers unnecessarily reduce, or over-reduce, their load during peak periods. The Authority estimates the impact of this effect as between a benefit of $11 million to a cost of $96 million in present value terms. The working paper quantifies this problem by considering different scenarios for the size and cost of peak load reduction in the RCPD regions. This is compared with the benefits of deferred transmission investment in the UNI and USI.

However, the most direct financial reason for EDBs to control load is to manage distribution network capital expenditure. Accounting for distribution benefits and avoided costs to direct-connect customers, we find an overall impact of between a benefit of $4 million and a cost of $18 million in present value terms.

The working paper overlooks the incentives and benefits from reducing peak load

Peak load reductions occur for multiple reasons, mostly relating to reducing costs to the party involved. For the purposes of this analysis, we focus on EDBs' incentives to control load to manage transmission costs and to lower their own distribution capital expenditure.

EDBs do not have a direct financial incentive to minimise transmission charges. This is because EDBs are able to pass transmission charges straight through to retailers (transmission charges are treated as recoverable costs in distribution pricing regulation). However, EDBs can help to lower their customers' electricity bills by actively controlling load for transmission pricing reasons. Given that many EDBs in New Zealand are consumer-owned or have direct consumer representatives on their Boards, this is likely to be a real reason to control load.

At the same time, EDBs have a strong financial incentive to defer growth capex. EDBs directly benefit from the return on capital (weighted average cost of capital) and the return of capital (depreciation) that they earn on capital expenditure that is factored into their price path but is not spent within the five year regulatory period.[6]

So how much load control can be attributed to transmission charges, and how much is to defer distribution capex? The Authority approaches this question by testing the impact of two different assumptions: that either 1.5 percent or 5 percent of peak load is controlled to manage transmission charges. We suggest that a better approach is to investigate how much load EDBs would rationally control to defer growth capex, and then to assign any residual load control to transmission charging reasons. Our analysis below takes this approach, which reflects our approach to the problem definition as a whole because this load control would happen regardless of what TPM is adopted.

For most EDBs, capex deferral benefits are sufficient to incentivise peak load reduction

In applying this approach we estimate the deferral benefit using EDBs' maximum peak demand (from the 2013 information disclosures) and deferred distribution capex (calculated from Commerce Commission's Summary and Analysis of Information

[6] Non-exempt EDBs receive an allowance for forecast capital expenditure that is added to their regulatory asset base in under the default price-quality path.

Disclosures 2013).[7] We focus on the case of a 5 percent reduction in peak load (as the Authority states this is around the level observed by EDBs) and assess the extent to which this reduction is justified by deferring distribution capital expenditure.

We assume a one-year deferral in capex relating to system growth (using the 8 percent discount rate applied by the Authority) and apply straight-line depreciation assuming an average asset life of 45 years.[8] The high cost of load control used by the Authority appears inappropriate (and may not account for the fact that for hot water control, load is not shed but managed, with a subsequent increase in demand). Instead, we use the more up-to-date cost information from Transpower's review of its 2013 demand response programme, where the minimum cost of reducing peak load is $120 per MW and the maximum cost is $500 per MW.[9] All other variables are the same as those used in the Authority's analysis.

We explore two scenarios for the cost of reducing peak load:

- **A low cost case** using a minimum cost of $120 per MW to reduce peak load by 5 percent over either 20 or 50 trading periods (depending on the EDBs' region as in the Authority's analysis)
- **A high cost case** using a maximum cost of $500 per MW to reduce peak load by 5 percent of over either 50 or 100 trading periods (again, depending on the EDBs' region).

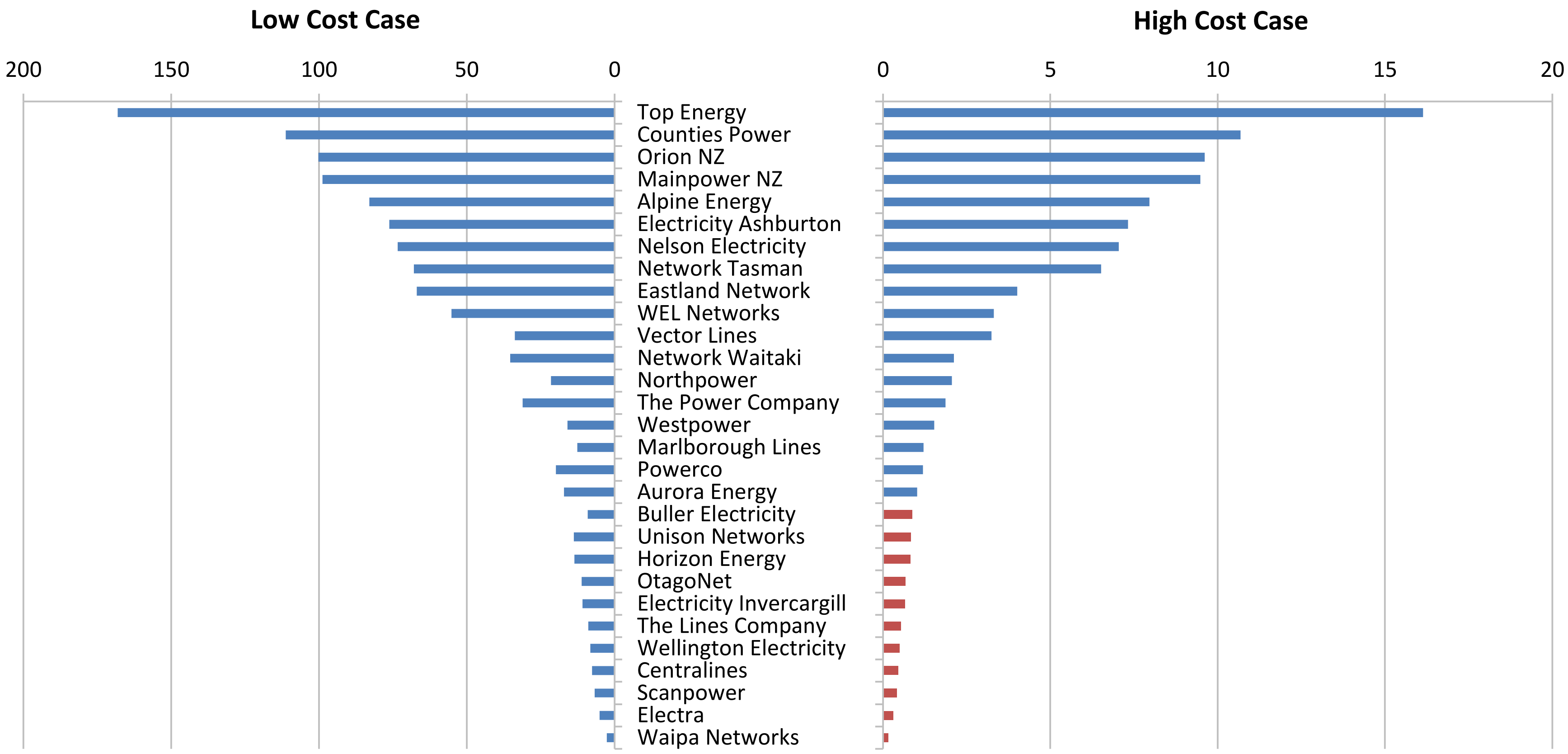
Figure 3.1 shows that for most EDBs the benefit from deferred distribution investment necessary to meet load growth exceeds the cost, under both scenarios. For those where the costs are not fully offset (highlighted in red), there is still some distribution benefits that needs to accounted for when analysing the net impact.

7 See tab "T9 & T10" of spreadsheet "Electricity summary database for March 2013 information disclosures" available at: http://www.comcom.govt.nz/regulated-industries/electricity/electricity-information-disclosure/electricity-information-disclosure-summary-and-analysis/summary-and-analysis-of-information-disclosed-in-march-2013/. Forecast changes to system growth capex are added or subtracted from historical figures for each EDB as appropriate

8 This lies in the mid-point of the range of asset lives for various assets (and is one of most common asset lives) included in Schedule A of the Commerce Commission's Electricity Distribution Services Input Methodologies 2012, available at: http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/electricity-distribution/

9 Available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Demand%20Response%20Programme%20Report%20Summary.pdf

Figure 3.1: Benefit Cost Ratios of Peak Load Reduction for EDBs



Note – Red bars indicate a benefit cost ratio of less than one (meaning benefits of controlling load for distribution capex reasons alone do not exceed the costs)

Direct-connects face a smaller incentive to control load for non-transmission benefits

The Authority also notes that a number of direct-connect customers respond to peak charges. Further, it reports there is no cost to Norske Skog responding to peak charges. However, to be conservative (and given data availability), we assume a cost to all direct-connect customers consistent with that observed in Transpower's demand response review.[10] In addition, we account for the partially offsetting benefit in terms of avoided spot prices during these peak periods.

We use Transpower's prudent estimate of peak demand to assess the cost to direct-connect customers of responding to RCPD signals. We use the peak demand estimate for the nodes of the direct-connect customers that the Authority states respond to peak signals.[11] The costs of reducing peak load are again taken from Transpower's review of its 2013 demand response programme.[12] We apply the same 5 percent reduction in peak load as for EDBs as we do not have better information on the extent of response from these direct-connect customers. The avoided wholesale price for direct-connect customers uses the $85/MWh marginal price applied elsewhere in the Authority's paper. All other variables are taken from the Authority's analysis. We find that all direct-connect customers' costs of load control outweigh their benefits from avoiding wholesale prices.

We find that the inefficiency of RCPD over-signalling for load reduction during peak periods ranges from a benefit of $4.5 million to a cost of $17.7 million in present value terms. Table 3.2 shows the findings for the low and high cost cases for EDBs and direct connects customers to reduce their peak load.

Table 3.2: Inefficiency Estimates from Load Control by EDBs and Direct Connects

Present Value Impact	Low Cost Case ($m)	High Cost Case ($m)
Net cost to those EDBs where not in direct interest	0.00	16.10
Net cost to flexible direct-connect customers	0.52	16.59
Transmission benefit	-5	-15
Net inefficiency	-4.5	17.7

3.2 RCPD Over-signals the Need to Reduce Consumption

The Authority notes that not all consumers can respond to price signals and instead these consumers may respond by reducing their overall level of consumption. The Authority quantifies this inefficiency to be between $4 million and $40 million in present value, estimating the response to transmission charges based on:

- Electricity consumption,

[10] The Kawerau papers mills are modelled together as information on load was only available at this aggregate level.

[11] We include all paper mill load at Kawerau (using load for Kawerau T6-T9 and T11/T14 but excluding Kawerau Horizon), NZ Steel Glenbrook Mill, Pan Pac Forest Products (applying all Whirinaki load), and Methanex NZ.

[12] Available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Demand%20Response%20Programme%20Report%20Summary.pdf. We apply this to paper mill load at Kawerau, which includes Norske Skogg (as noted above) so this may slightly overestimate the cost to direct-connect customers.

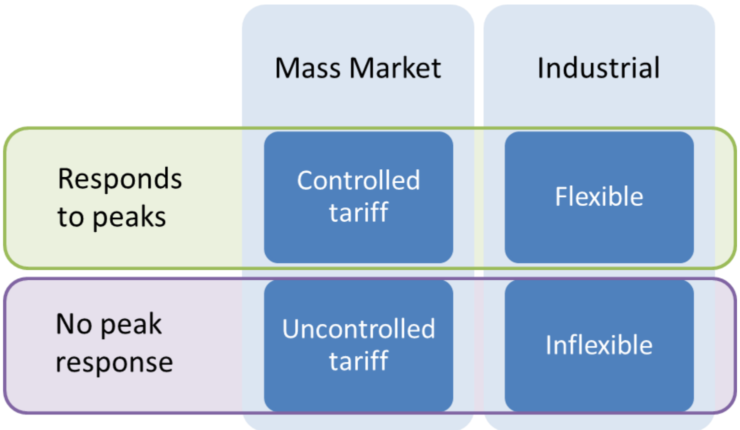
- The assumed long-term price elasticities of demand for different consumer groups, and
- Different scenarios for the proportion of industrial consumers considered to be elastic, inelastic, or have the same elasticity of demand as mass market consumers.

This estimated response is then compared with the outcome using Ramsey pricing under the same assumptions.

The analysis must distinguish parties that do not respond to peak price signals

Conceptually, it is important to distinguish this inefficiency from the inefficiency considered in Section 3.1 by excluding consumers for whom we have estimated the effect of reducing peak demand above. It is also useful to separate the effects on mass market consumers and for industrial consumers that do not respond to peak pricing signals. These distinctions are important to avoid double-counting and are illustrated in Figure 3.2. A potential example of double-counting would be including customers on controlled tariffs when calculating an overall reduction in demand for mass market consumers (as these consumers already respond to peak signals by having their hot water controlled, as accounted for in Section 3.1). The green box in Figure 3.2 illustrate the impacts considered in Section 3.1, while this this Section focuses on the two separate elements in the purple box.

Figure 3.2: Distinguishing Impacts of RCPD Charges to Different Consumers



Any mass market inefficiencies result from distribution pricing, with minimal residual concern with the TPM

Customers on controlled tariffs respond indirectly to peak signals by allowing EDBs to control their load (for example hot water, as discussed above). The impact of this has been assessed in Section 3.1 (and it is important to avoid double-counting). However, customers on uncontrolled tariffs do not face the peak pricing signal directly.

Inefficiencies for those on uncontrolled tariffs stem from distributor pricing rather than the TPM. If transmission charges exceed the direct cost of supplying the consumer,[13] this is typically reflected in the variable charge faced by the consumer (given regulations on fixed tariffs for low users). However, any concern of these consumers reducing overall demand rather than responding to peak signals stems from distributors' pricing structures

[13] As shown in the left side of the Long Run Average Cost graph in Figure 2.1

not reflecting underlying costs. This is an issue with distributor pricing and should be considered a problem to be dealt with outside of the TPM.

There may be a residual TPM issue from a greater inefficiency in responding to the peak signal that would otherwise occur (if such signals were passed on). However, as discussed in Section 3.1, this is not expected to be large and may be offset by savings to distributors in terms of deferred capital expenditure. Therefore this component of the inefficiency would be much less than the cost estimated by the Authority of $3 million to $10 million in present value.

RCPD charges are not the main driver of operational (or investment) decisions for industrial consumers

The Authority's working paper states that New Zealand Steel, Norske Skog, and PanPac respond to RCPD peak signals (the impact of which is modelled in Section 3.1) and the costs of doing so are not large for Norske Skog and PanPac. The Authority also states that the Tiwai smelter does not respond in the short-term to RCPD signals (although it takes interconnection charges into account in longer-term decision-making). It further states that it does not have information to suggest that Carter Holt Harvey, Winstone Pulp International or KiwiRail respond to RCPD signals.

For those direct-connect customers who do not respond to RCPD signals, this may be because:

- Their electricity consumption is largely (or fully) outside the RCPD periods, limiting the potential to respond
- It is still more economical to continue to consume and simply pay the additional interconnection charges, or
- They are unable to respond: they do not have the systems to withdraw demand or cannot interrupt operations while in progress.

The Authority notes that these parties do not respond (that is, are inelastic) in the short-term but suggests that in the long-term there is some potentially significant response.

There are likely to be thresholds when industrial consumers consider whether to invest or retire capacity, where interconnection charges may be a consideration. However, these charges would be among other more significant factors such as product prices and other input costs such as capital, labour, and transport.

The Authority's paper discusses such decisions for Tiwai, which is the main driver of this inefficiency (under the worst case scenario). However, rather than justifying a high elasticity for industrial load, this suggests Tiwai should be considered separately.

Ideally, the Authority would investigate how any variation between the RCPD charges Tiwai faces and the cost to provide Tiwai transmission services might impact Tiwai's production decisions and the resulting demand for electricity. This analysis could consider the (extreme) possibility of Tiwai not increasing production as a result of RCPD charges, or of reducing production in future as a result of RCPD charges (noting other factors, particularly aluminium prices, will have more influence on this decision).

Transpower's review may address this problem or reduce its scale

Transpower has identified potential solutions to reduce RCPD signals that may address this issue. Transpower's review will consider combining RCPD regions and increasing the number of periods used to calculate RCPD charges. These changes would reduce RCPD signals, and therefore any problems associated with over-signalling, without changing the overall TPM design. This suggests the underlying problem with the current

TPM design in terms of inflexible industrial consumers reducing demand in response to over-signalling is likely to be less than the Authority's initial estimate.

Removing the inefficiency attributed to mass market consumers leaves an inefficiency of $0 to $30 million. Further, peak charges would likely be dwarfed by the other many, and more significant, drivers of industrial consumption, and Transpower's review has the ability to reduce the inefficiency further. Therefore, we consider the size of this problem to be lower than the Authority's estimate of $3 million to $40 million in present value terms.

3.3 RCPD Over-signals the Cost of Increasing Tiwai's Production in the Summer

The Authority estimates that there may be a productive inefficiency of around $4 million to $32 million, in present value terms, deterring the Tiwai smelter from increasing production in the summer months. This inefficiency results from Tiwai paying a greater portion on interconnection charges if they substantially increased summer production by shifting the LSI to becoming (at least partly) summer peaking. Despite sufficient transmission capacity (and therefore minimal short-run marginal cost, as discussed in Section 2), this increase in interconnection charge is sufficient to deter this increase in capacity. We agree with the Authority that the disincentive for Tiwai to produce in the summer months is inefficient (as the price exceeds both the short and long-run marginal cost of transmission).

Transpower also raises this issue as part of its operational review of the TPM where it signals it will investigate merging RCPD regions. This would address the problem as Tiwai's demand would be a lower proportion of a wider-regional demand and therefore have much less influence on when the wider regional peaks are. Therefore, this issue is one that may be dealt with within the existing TPM design and may not a problem that needs to be addressed via the TPM guidelines, but can be addressed via operational changes to the current TPM.

The inefficiency is driven by Tiwai's unique circumstances

It is unsurprising that applying the signals for all other electricity consumers to the Tiwai Point smelter results in inefficiency. Tiwai is unique in the scale and nature of its electricity demand. The Tiwai smelter accounts for around 16 percent of the electricity consumption in New Zealand, more than double that of the next largest industry (wood pulp, paper, and printing, of which there are a number of sizable companies and facilities involved).[14] Tiwai also has a unique wholesale energy contract, which it negotiates with Meridian Energy.

However, Tiwai's unique circumstances will not change as a result of a change to the TPM. Furthermore, if the TPM is adapted to work for Tiwai's situation, it may distort signals to the rest of consumers and require further review if Tiwai's circumstances significantly change. Alternatively, if the TPM is based on the behaviour of the majority of electricity consumers, the current inefficiency created by Tiwai's decisions may persist.

Bespoke solutions may offer a more effective means to resolve the inefficiency

A relatively straightforward way to remove the inefficiency would be for the Authority to recommend that Transpower engage with the New Zealand Aluminium Smelter (owners

[14] Source Ministry of Business, Innovation and Employment. See: http://www.med.govt.nz/sectors-industries/energy/energy-modelling/data/electricity

of Tiwai) to develop an individual contract for transmission charges. This could be achieved through adjusting the prudent discount policy (PDP) requirements. The adjustment could allow the PDP to be applied in cases of very large consumers where there may not be a credible non-transmission alternative but where the counterfactual is inefficient or avoids net beneficial use of the grid.

These kinds of bespoke approaches are common outcomes of competitive processes (even in a regulated natural monopoly setting). An example of this is the approach the Ports of Auckland (and subsequently Ports of Tauranga) have taken to establishing charges for Maersk/Fonterra where the nature of demand far exceeds other customers and therefore a bespoke approach has been used in order to set charges that encourage activity while still recovering appropriate costs.

As this inefficiency could either be mitigated by Transpower's review or resolved through a PDP, we report this impact separately from the others identified by the Authority.

4 HVDC Charges

Currently, the costs of the HVDC assets are recovered using the Historical Anytime Maximum Injection (HAMI) allocation. This section examines each of the problems quantified by the Authority resulting from HVDC charges (or HAMI allocations). We test whether the Authority's assumptions are appropriate, and suggest improvements to the quantification of these problems.

The Authority identifies four problems with the HVDC charge/HAMI allocation

The Authority notes that the decision to levy the HAMI charge only on South Island generators is controversial. However, despite the Authority's interest in the potential inefficiencies of the HAMI charge, the Authority avoids exploring potential problems around who should be carrying the cost of the HVDC assets. This implies that the Authority does not consider the current allocation of HVDC costs to South Island generators as a problem.

Instead, the Authority has focused on quantifying the inefficient impacts that the HAMI charge potentially has on generation capacity and transmission investment in the South Island. The Authority considers that the HVDC charges and the HAMI allocations:

- Incentivise South Island generators to withhold existing capacity
- Discourage:
  - Upgrades to South Island generation capacity
  - Investment in South Island grid-connected generation
- Bring forward the need for upper South Island transmission investment.

Our analysis below focuses on the problems that the Authority has quantified and which make a material difference to the overall estimated size of the inefficiency. Table 4.1 summarises our approach to the problems identified by the Authority.

Table 4.1: Reframing the Problems Identified with HVDC Assets

Inefficiency	Authority's evaluation	Authority's estimation	Elements overlooked in the evaluation	How our analysis incorporates these elements	Adjusted estimation
Incentivising SI generators to withhold existing capacity	South Island dispatch is less than optimal if the HAMI allocation causes the combined SRMC and the HVDC charge to be greater than the additional revenue from existing SI plants/capacity	PV$12M	A change to MWh (or "incentive-free") would largely resolve this issue	▪ Examines whether existing HAMI causes generation to offer at higher prices ▪ Considers potential market outcomes (e.g. adding HVDC charge to all SI bids) from a MWh charge	PV$0-$12M
Discouraging upgrades or new investment in SI generation capacity	South Island dispatch is less than optimal if the HAMI allocation causes the combined LRMC and the HVDC charge to be greater than the additional revenue from new SI plants/capacity	PV$25M ***if*** substantial new generation needed	New capacity is expected to be built in the North Island (or not built)	Compares the GEM model of the merit order with and without HAMI, adjusting for lower forecast demand growth, and use the difference in cost as the value of inefficiency	PV$4-$9M
Bringing forward the need for USI transmission investment	A transmission solution is required as a result of USI generation opportunities not being developed	PV$2M-$6M	▪ May require a change in the economics of USI generation opportunities ▪ Transpower could contract for transmission alternative services. It has recently paid for Demand Response in the USI	Identifies the need for new transmission investment using the USI plants that are deferred as a result of HAMI (identified using the GEM analysis)	No residual inefficiency from TPM guidelines
Total		**PV$14M-$43M**			**PV$4-$21M**

Source: Castalia analysis of Electricity Authority "Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets".

4.1 HAMI Incentivises Withholding Existing South Island Generation Capacity

The HAMI allocation methodology is based on the highest maximum injections at a grid-connected point in the past five years. The Authority notes this methodology creates a high marginal cost to generators offering capacity above their highest previous injection. It suggests that this results in a disincentive for generators to offer full capacity in the case that this may increase their HVDC charges for the next five years.

The Authority estimates the impact of this effect by calculating the difference in the vectorised Scheduling, Pricing, and Dispatch (vSPD) objective function between actual and simulated outcomes. The simulated outcomes assume Contact and Meridian offering full capacity of Clyde, Roxburgh and Benmore when it is assumed they would be physically able to do so. The Authority estimates the impact to be an inefficiency of $12 million present value, noting there has been significant disagreement in the past on the scale of this inefficiency.[15]

We agree the current HAMI charge creates a high marginal cost to running additional capacity beyond that previously offered. However, if this were generators' only consideration, we would expect this cost to simply be priced into offers (rather than withholding capacity). It may be that the marginal cost is so high that, whether the capacity is withheld or offered at a price reflecting this high cost, ultimately the effect is the same.

This is also an issue that Transpower has raised as part of its operational review of the TPM. Transpower has signalled it will investigate moving to:

- **A MWh charge**. This would spread the HVDC charges across all dispatched offers and would be expected to affect offers from South Island generators. The Authority could estimate the remaining inefficiency under this option by adding the expected per MWh HVDC charge to South Island generator offers as well as including the expected additional capacity in its vSPD modelling. The difference in the vSPD objective function would be the remaining inefficiency.
- **An "incentive-free" charging mechanism**, such as charging based on nameplate capacity or kW capacity of the connection asset (possibly applied above a minimum capacity factor with a MWh charge applied below). This charging mechanism would remove the incentive to withhold capacity (as charges are already based on such capacity). Likewise, averaging over multiple injections or years would also reduce the incentives to withhold capacity.

To the extent that Transpower's review is able to provide solutions that reduce or eliminate this problem, this issue is not confined to the TPM guidelines and can be addressed without changing the methodology completely.[16] Any residual inefficiency would be less than $12 million in present value, such that the problem may be towards the lower end of $0 to $12 million in present value.

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[15] For example, the Electricity Commission estimated it was towards the lower end of a $0-$100 range, while TPAG considered it to be more likely in the range of $0-$10

[16] We note that moving to a MWh charge may influence offers for all bands of major South Island capacity

4.2 HVDC Charges Discourage Upgrades or New Investment in South Island Generation Capacity

The Authority considers that the HAMI allocation may discourage upgrades to South Island generation capacity and the overall HVDC charge may discourage investment in generation in the South Island. We treat these problems together in this report. This is because both upgrades and new investments will be inefficiently deferred if together the LRMC and HAMI allocation are greater than the additional revenue from the new plants or capacity. To determine whether this is occurring, we consider upgrades to capacity alongside new investments in the merit order for new generation. In doing so, we investigate the potential impact of the current HAMI allocation on the dispatch on South Island options. Our approach is consistent with the earlier analysis completed by the Transmission Pricing Advisory Group (TPAG) in 2011, although (as we noted in Section 4.1) there have been several debates about its findings. We simply update the earlier analysis by TPAG (made available by the Authority on its TPM review webpage) to reduce demand growth to be consistent with Transpower's latest planning documents.

The Authority's paper concludes that the issue of discouraging upgrades to capacity is probably small. In respect to discouraging investment in South Island grid-connected generation, the Authority suggests the impact may be in the order of PV$25 million ***if*** there is a need for substantial new generation over the next few years. However, the Authority notes that there is currently an oversupply of capacity and increased likelihood of Tiwai reducing production, freeing up existing capacity, ultimately noting the TPAG estimate of PV $24 million may be an overestimate. We agree that the TPAG central estimate is likely to overestimate this impact and note that the demand outlook has reduced since 2011 (shown by the revisions to the demand growth assumptions in Transpower's Annual Planning Reports).

To test a more realistic estimate in current sector conditions, we apply the most recent demand growth assumptions used in Transpower's 2014 Annual Planning Report[17] (1.2 percent average growth between now and 2029, which equates to a starting point of 1.4 percent growth given the model incorporates declining demand) to TPAG's model.[18]

Our analysis suggests an estimated inefficiency of around $4 million to $9 million in present value under the TPAG's base case.

Table 4.2 shows the complete set of sensitivities for this lower demand case, where project costs are varied by p±20 percent for each class of investment, for which the impacts range between $4 million and $33 million in present value.[19] The updated analysis may still overstate the size of this inefficiency as a greater share of South Island generation options have been "shelved" since TPAG consolidated the list of potential future projects (as noted by the Authority in paragraph 11.152).

17 Available at: https://www.transpower.co.nz/resources/annual-planning-report-2014

18 TPAG's model is available on the Authority's website at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c2120

19 This compares with estimates of between $14 million and $51 million in the TPAG's initial analysis when all sensitivities are considered

Table 4.2: Update to TPAG's Assessment of HVDC Inefficiency for New Investment

2011 Analysis			Updated Analysis[20]		
Sensitivity Analysis			Sensitivity Analysis		
HVDC Charge $35/kW	Economic Cost $m PV		HVDC Charge $35/kW	Economic Cost $m PV	
Sensitivity	Base Case	Low Gas Cost[21]	Sensitivity	Base Case	Low Gas Cost
Current Exchange Rates	$18m	$25m	Current Exchange Rates	$9m	$9m
Long Run Exchange Rates	$16m	$25m	Long Run Exchange Rates	$4m	$8m
Random Capex 1	$34m	$37m	Random Capex 1	$20m	$25m
Random Capex 2	$37m	$41m	Random Capex 2	$24m	$30m
Random Capex 3	$27m	$30m	Random Capex 3	$11m	$15m
Random Capex 4	$28m	$38m	Random Capex 4	$13m	$18m
Random Capex 5	$27m	$43m	Random Capex 5	$12m	$19m
Random Capex 6	$45m	$51m	Random Capex 6	$24m	$33m
Random Capex 7	$17m	$25m	Random Capex 7	$6m	$11m
Random Capex 8	$14m	$20m	Random Capex 8	$6m	$8m
Random Capex 9	$42m	$47m	Random Capex 9	$23m	$30m
Random Capex 10	$30m	$29m	Random Capex 10	$12m	$15m
Average	$28m	$34m	Average	$14m	$19m

Source: Castalia analysis using TPAG's model

4.3 HVDC Charges Bring Forward the Need for Upper South Island Transmission Investment

The Authority also raises the problem that the HVDC charge may accelerate the need for transmission upgrades between Waitaki Valley and Christchurch by discouraging generation investment in the upper South Island (USI). The Authority estimates the size of this impact by considering Transpower's planned investment in the area and calculating the "deferral benefit forgone" if this investment is brought forward. It considers the case of this investment being brought forward either one year or by three

[20] This uses the analysis initially undertaken by the TPAG and updates for demand growth assumptions. We have not reassessed each of the other elements (such as the level of the HVDC charge). Given the longer term outlook, these figures should also be seen as averages over time

[21] Consistent with TPAG's original paper, the base case scenario assumes that gas supply remains limited (and reflected in resource prices). Under this scenario existing Combined Cycle Gas Turbine (CCGT) capacity is maintained and most new capacity is geothermal, hydro or wind over the next 30 years. The low gas cost scenario is based on a significant new gas discovery at $8/GJ which would support some additional CCGT gas plant beyond 2025

years as a result of the HVDC charge and it prevents the construction of an equivalent generation plant in the USI.

For the HVDC to be the main driver to defer USI generation projects, we would expect to see these projects in the merit order if one assumes no HVDC charge. Using the TPAG modelling used in the previous section (applying the reduced demand growth), we find that without the HVDC charge:

- No USI projects are expected to be commissioned before 2022 (when transmission investment is forecast to be required based on prudent demand forecasts), and
- Only one project is expected (70MW Clarence to Waiau Diversions) to be commissioned prior to 2030 when transmission investment is expected to be required based on expected demand forecast.[22]

However, even assuming there are USI options that are cheaper than the transmission investment that have been deferred due to HVDC charges, does not necessarily cause a problem. The Authority acknowledges that Transpower is already able to avoid any inefficiency of transmission investment by procuring new generation in the USI as a non-transmission alternative. In fact, it is a requirement of transmission investments to consider non-transmission alternatives and if alternatives are more efficient, then the transmission investment should not be approved.

Furthermore, we note that those who have developed the USI generation options have every incentive to ensure that Transpower and the Commission are aware of these options and encourage them to pursue these options. Any decision to pursue transmission investments ahead of these more efficient options would therefore only be as a result of a failure by both Transpower and the Commission. This should be unlikely to occur and, if it does, would be a problem with these processes as opposed to the design of the TPM. Given this assessment, we recommend excluding this estimated inefficiency from any assessment of the problem definition.

22 This finding holds under the base case and unconstrained gas case

5 Implications for the TPM Review

The role of the problem definition is to inform the TPM review so that options are evaluated against a consistent framework, and the preferred option actually resolves the problem initially identified. This section summarises the findings of our analysis and discusses how these should be incorporated into the cost benefit analysis of TPM design options.

After adjusting the efficiency of market operations estimates to reflect the analysis in this paper, we find the size of the problem that relates to the TPM specifically to be around $4 million to$101 million in present value. This adjusted figure excludes:

- The Authority's durability figures for the reasons noted in Section 1 and set out in Genesis Energy's analysis—chiefly that we do not believe engagement by various parties can solely be considered a cost and do not expect any TPM changes to significantly reduce costs for market participants
- The issues that the Authority has not quantified. This includes the efficiency of transmission investment decisions which Genesis Energy's submission addresses and ACOT which the Authority is still considering.

The adjusted problem definition reveals the greatest net benefit potential solutions could achieve

The Authority intends, as encouraged by market participants, to specifically link the cost benefit analysis of options to the analysis and quantification of the underlying problem in this working paper. One way to achieve this is to use the problem definition, adjusted for the findings of this analysis, as the upper bound for the net benefit of any of the options to be considered. It appears unlikely that any solution would create wider benefits (increasing the upper bound beyond the present value $101 million) that are not considered in the problem definition. Realistically, the net benefit of a solution is likely to be less than the upper bound as no TPM design will be perfect or be able to address all of the identified problems simultaneously (a fact the Authority's paper identifies).

Further, even if an option could produce a $101 million net benefit, there may not be sufficient justification for major changes beyond those currently being considered within the existing guidelines. This is due to the additional risk such wider changes may introduce.

Methods for analysing options should be consistent with those used to assess the problem

The analytical approaches used to investigate and quantify problems in the working paper and this report should be replicated (and possibly extended) when analysing options. This will ensure that the options can be consistently compared to whether they mitigate or resolve the initial problem.

As a purely illustrative example, the Authority could decide to investigate changing the TPM guidelines to require a beneficiary pays approach to set charges. In this case, we would expect the cost benefit analysis of this option to consider its impact on each of the problems identified by the Authority, as well as considering any other costs and benefits. In particular, the analysis would need to assess the extent to which beneficiary pays pricing would address the problems associated with interconnection and HVDC charges. If beneficiary pays pricing was found to fully address all current problems, this would amount to a maximum benefit of present value $101 million (using our estimates), which would then need to be assessed relative to the costs of this alternative option (including transition costs).

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