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New Zealand Transmission Pricing Project

A Review of the NERA Report to the Electricity Industry Steering Group

Report to MEUG

1st September 2009

Preface

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NZIER was established in 1958.

Authorship

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1. Introduction

NERA Economic Consulting (NERA) has been commissioned by the Electricity Sector CEOs' Forum (CEOs' Forum) to prepare a report on ways in which the efficiency of electricity transmission pricing arrangements in New Zealand could be improved (the Report). The hope of the CEOs' Forum is that the Report will increase the degree of consensus among all the stakeholders in the electricity sector about how to reform the transmission pricing methodology (TPM). The TPM is currently being reviewed by the Electricity Commission and a greater consensus among stakeholders would facilitate the Electricity Commission's decision making.

NERA with the assistance of an industry Working Group has produced a Report for consideration by the Industry Steering Group [1] which the CEOs' Forum established to oversee the project. MEUG has asked NZIER to consider the written comments that have been submitted by MEUG Working Group members, a discussion of the representatives of consumers on the Working Group and the Steering Committee and the Report and provide it with a review. The purpose of the review is to provide feedback to the Steering Group on the Report and the various options for reform of the TPM it proposes.

The Report contains a number of weaknesses of economic analysis and misinterpretations of the current regulatory regime which are significant to the conclusions reached and the options proposed. As a result, not one of the reform options identified in the Report will improve the efficiency of transmission pricing arrangements in New Zealand; in fact, in our opinion, the options are all less likely to promote efficient outcomes than the current methodology. This is not because the current methodology cannot be improved; it is because the options identified by the Report will not help do so.

The options in the Report are generally more favourable to most generators in terms of the transmission charges they will bear than the *status quo* without adversely impacting the interests of distributors or Transpower. Indeed, aspects of the proposals favour distributors and/or Transpower, also. On the other hand, all the options adversely impact the charges consumers, including directly connected consumers, are likely to bear compared with the *status quo*. Instead of increasing consensus among stakeholders, the Report is likely to increase the difficulties of finding a consensus on the topic. A report that ends up with options favourable to its principal sponsors at the expense of other parties, but relies for its conclusions on analysis which contains weaknesses and misinterpretations of the current regulatory regime is unlikely to engender a climate in which greater consensus is likely.

[1] NERA Economic Consulting. *New Zealand Transmission Pricing Project: A Report for the New Zealand electricity Industry Steering Group*, 28 August 2009.

We start by critically analysing the potential problems the Report identifies with the current TPM. We then consider the high level options for reform proposed and discuss why we think they will not improve efficiency.

2. NERA's evaluation of the current TPM

2.1 Summary of the assessment

NERA concludes that many features of the existing transmission pricing arrangements are fundamentally sound and are consistent with the objectives that it:

- *sends efficient locational signals (assuming these signals are not adequately provided elsewhere);*
- *sends efficient signals to encourage, among other things efficient demand-side response;*
- *sends efficient signals as to the timing and nature [as well as the location] of new generation development; and*
- *endures in line with the time frames for investment decisions so as to provide certainty as to the nature and extent of those price signals to all stakeholders.*[2]

However, according to the Report, the existing arrangements exhibit a number of potential problems:[3]

- the combination of nodal prices, losses, deep connection charges and the grid investment test (GIT) may not be sufficient to signal the long-run marginal cost (LRMC) of transmission investment
- the circumstances and manner in which the GIT is undertaken are potentially problematic – most notably because each transmission investment is considered in isolation
- the existing 'deep' connection charging regime has the potential to distort the long-run investment cost signals associated with different generation alternatives, specifically:
  - because connection charges can vary substantially upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment signals can be created in some circumstances
  - the arrangements for recovering the costs of 'shared' connection assets may give rise to significant step-changes in connection charges as 'beneficiaries' change over time, which can reduce certainty and further harm dynamic efficiency and

[2] NERA, p. i.

[3] NERA, p. iv.

- the arrangements may give rise to 'first mover' problems, whereby individual generation proponents are unwilling to pay the deep connection charges to connect new generation locations

- the locational signal provided by the HVDC charge may be inappropriate, and in any case is incapable of providing *intra-island* locational signals; the reasons it may be inappropriate are:
  - the historic peak injection parameter (HAMI) theoretically provides incentives to withhold supply of peak capacity
  - the incidence of the HVDC charge may reduce incentives to invest in the South island, particularly in peaking capacity and
  - the HVDC charge increases the likelihood that new investment will be undertaken by established incumbent South Island generators, notably Meridian.

2.2 Adequacy of signals

NERA argues that the overall transmission price difference between two locations, such as Auckland and the deep-South, should reflect the LRMC of transmission between the two locations that is not already reflected in the nodal price differential. The logic of this statement is that in this circumstance the price differential facing a generator, should it locate in one location compared with another, will reflect the LRMC of transmission between the two locations. If this holds, then generators will be encouraged to locate efficiently, given the costs of transmission to society.[4]

NERA, however, claims that this rule is not easy to implement in practice "because the LRMC of the transmission capacity needed to serve any particular location *changes over time* as new capacity is added."[5] More specifically, the Report argues that because of economies of scale it is efficient to add new transmission capacity in lumpy units and this leads to the LRMC of transmission capacity fluctuating over time – rising as existing capacity approaches being fully utilised, falling sharply once capacity is increased and then rising again as utilisation of the higher level of capacity increases. Figure 2.1 of the Report sets out in a stylised manner the Report's view of how the LRMC of transmission capacity fluctuates.

NERA's analysis does not describe the LRMC of transmission capacity, which is the capital and operating costs that would be incurred to increase transmission capacity (as opposed to throughput) by one unit. Setting aside the potential impact on the costs of transmission equipment of exchange rate fluctuations, in real terms this cost is likely to be reasonably steady over short time periods and slowly decline over longer time periods. The long-term decline is to be expected as efficiency improvements in the production of transmission equipment occur. There could also be steps downward in the cost curve if there were a material improvement in the

[4] NERA, p. 13.

[5] NERS, p. 13.

technology of producing transmission equipment or the technology of transmission itself.

From the discussion, it appears that what NERA may have in mind when concluding there will be a cycling pattern is movements in the short-run average cost (SRAC) of transmission services. This will cycle if demand and production increase and existing capacity gets increasingly utilised and then periodically expanded, but it will cycle in the opposite manner to what NERA's Figure 2.1 suggests. Immediately extra transmission capacity is added, the SRAC of transmission services will jump upwards, but as throughput increases the SRAC will decline. It will continue to do so until the next increment in capacity has to be added when it will again increase sharply before declining as the spare capacity is increasingly utilised.

The practical conclusion that NERA draws from its flawed analysis that the LRMC of transmission capacity will cycle is that it will be difficult to design a TPM that would provide the correct locational signals. NERA argues that to design such a signal "it is likely to be necessary to come to a view on where one might feasibly introduce a *durable* signal that will need to be regularly changed (e.g. annually) as market circumstances develop."[6]

NERA's scepticism about determining a *durable* LRMC of transmission capacity underlies its caution about its own analysis of the LRMC of the HVDC and its implicit dismissal of the implications of that analysis that the HVDC charge currently levied on South Island generators is too low to provide an efficient locational signal. As we have shown, NERA's scepticism is based on flawed economic analysis and this aspect of its argument against the HVDC charge is poorly founded to the extent it is dependent on this view.

NERA's conclusion that "nodal prices, losses, deep connection and the GIT may not be sufficient to signal the long-run marginal cost (LRMC) of transmission investment"[7] is at odds with its proposal in two of the options it presents to replace "deep connection charges" on generators and load with shallow connection charges. If the price signals in the existing TPM are too weak to signal the LRMC correctly, and correct signalling of the LRMC would promote efficient locational decisions, it is curious that NERA favours weakening the signals rather than strengthening them. No explanation for this apparent inconsistency is provided in the Report.

2.3 Application of the GIT

A principal concern NERA raises about the application of the GIT is that there is presently no scope for the costs associated with 'nationally significant' or otherwise beneficial investments in 'large connection assets' to be socialised, if such investments pass the economic limb of the GIT. NERA's concern is that the building

[6] NERA, p. 15.

[7] NERA, p. iv.

of connection lines to areas where several new generators may locate is not catered for under the current arrangements.[8]

What NERA has overlooked is that building transmission connection assets is not a regulated activity in New Zealand. Anyone can invest in such assets – the party being connected, a joint venture of parties interested in being connected, Transpower or any other potential investor.

If Transpower builds the asset, its revenue and expenses related to this investment are not covered by its Commerce Commission regulatory regime. The regulatory regime only applies to 'specified services' and since there is workable competition in the provision of connection assets their provision is excluded from the definition of 'specified services'.[9] The Electricity Commission does not have to approve Transpower's investment in connection assets undertaken under contract either, as only those investments Transpower wishes to have security of revenue recovery for, provided it uses the TPM, need to be approved by the Electricity Commission. Connection assets are usually charged for under a new investment contract between Transpower and the party or parties that will use them.

What NERA is arguing is that it would be more efficient if Transpower, with the approval of the Electricity Commission, could make the decision to invest in 'large connection assets' and pass the costs and risks of asset stranding and inefficient investment on to load than it would be to continue with the current arrangements. Under the current arrangements, the provision of such assets is a contestable activity and investors that decide to provide them bear the risks and reap the rewards of their decisions.

We do not share NERA's view of the comparative efficiency of investment decision making and implementation under socialism. We think the arrangement proposed by NERA for the construction of 'large connection assets' will be significantly inferior to the current arrangement in regard to productive efficiency (the costs of the investment and level of over-runs), allocative efficiency (what gets built and how) and dynamic efficiency (the timing, etc.). We believe the history of investments under the New Zealand Electricity Department strongly supports our view. This history as it relates to generation investment has been reviewed in the recent Ministerial Review of electricity market performance.[10]

Another principal concern of NERA is that "when defining future market development scenarios for the proposed investment and alternatives the GIT only considers one transmission investment at a time."[11] This concern is based on a misinterpretation of the rules surrounding the application of the GIT.

[8] NERA, pp. 42-3.

[9] Commerce Act (Transpower Thresholds) Notice 2008, Clause 3 (1).

[10] Electricity Technical Advisory Group and Ministry of Economic Development, *Improving Electricity Market Performance*, Vol. 2, p.57.

[11] NERA, p. 43.

Under the GIT, the base case used must be reasonable in having regard to the "operating and maintenance costs of efficiently supplying demand by means of existing assets, committed projects and modelled projects"[12] and "the capital costs of efficiently supplying demand by means of modelled projects"[13]. Similarly, the supply-side of any market development scenario **must include** committed projects, the decommissioning of assets and 'modelled projects'.[14] 'Modelled projects' means transmission augmentation projects and non-transmission projects, other than the proposed investment and alternative projects, which are likely to occur and can be reasonably expected to occur in a market development scenario.[15] 'Non-transmission projects' include investment in: generation; energy efficiency; demand-side management; network augmentation; improvements to the systems and processes of the system operator; and provision of ancillary services.[16]

As a result of these provisions the Rules relating to the GIT require groups of potential transmission investments to be taken into account when assessing a single transmission investment. The Rules also require the prospect that other generators are likely to or can be reasonably expected to set up in an area to be taken into account when assessing a grid investment under the test. NERA's concern about the application of the GIT is mistaken.

2.4 'Deep' connection

NERA claims that "the existing 'deep' connection charging regime has the potential to distort the long-run investment cost signals associated with different generation alternatives".[17] We shall consider each of the grounds on which it makes this claim in turn.

2.4.1 Competitive neutrality for generation

a) Equality of charges is efficient?

NERA's first complaint about the 'deep' connection charge is that it disturbs the competitive neutrality between investments in different forms of generation. More specifically, it is concerned that generation embedded in distribution networks and generation directly connected face different costs and charges.

In NERA's opinion, "generation alternatives that offer similar net market benefits should, all things being equal, pay the same connection charge."[18] In our opinion, since the presumption of net market benefits being similar irrespective of the form of

[12] Electricity Governance Rules, Part F, Section III, Schedule F4, Clause 8.4.5.

[13] Ibid., Clause 8.4.6.

[14] Ibid., Clause 7.

[15] Ibid., Clause 29.

[16] Ibid., Clause 31.

[17] NERA, p. iv.

[18] NERA, p.45.

connection does not hold, this simple test proposed and used by NERA is not the correct economic test of whether charges are to lead to efficient outcomes. The correct economic test is if generators deciding whether to connect to a distribution network or directly to the grid face charges and payments that reflect the social costs and benefits of their choices. If the costs and benefits of alternative connection arrangements differ then so must the level, and probably the nature, of charges, if efficient outcomes are to be achieved.

In the Report, NERA catalogues at considerable length the different connection charges that a hypothetical generator would pay depending on whether it decided to connect directly or indirectly to an existing grid connection point or a new grid connection point, or to embed its generator in a local distribution network that is itself connected to the grid by connection assets. Since the assets required for the different connection options vary considerably between the options and it is conceivable the benefits in terms of security of supply in the local network do also, the charges faced by the generator should vary if the outcome is to be efficient. However, NERA incorrectly concludes:

> *In light of the broad spectrum of potential connection charges for which generators may be liable to pay based on their locational decision and the type of generation, it is not difficult to envisage generators' investments being distorted inefficiently and incentives being created, despite the good intentions of the deep connection regime.*[19]

In fact, consideration of the various alternatives outlined by NERA does not suggest any material reason why generators will not generally make efficient locational decisions when choosing between embedding and directly connecting. The existence of Transpower's prudent discount policy to forestall inefficient bypass of the grid helps ensure this in many situations.

In this regard, we are mystified by NERA's claim that "there [are] a number of situations where a prudent discount would *not* apply, including proposals to construct *new* embedded generation (since doing so would be considered contrary to the Government's October 2004 Policy Statement on embedded generation) …".[20] The provisions relating to distributed generation, by which is meant embedded generation, in the 2004 Government Policy Statement do not restrict the use of the prudent discount policy for new embedded generation. On the contrary, they are intended to ensure there are no unnecessary barriers to the development of this kind of generation.[21] Moreover, even if the GPS did contain the provisions NERA claims for them to have any effect Transpower would have to be instructed by the Minister accordingly. There is no evidence of any such instruction from the Minister in

[19] NERA, p. 48.

[20] NERA, p. 32.

[21] Government Policy Statement on Electricity and Gas Governance, October 2004, paragraphs 109-13.

Transpower's current Statement of Corporate Intent, but if there was one, and it is still in force, there should be.

If it is correct that a generator locating in an area provides advantages to the distribution network in terms of lower transmission charges, it will be easier for the generator to capture these benefits by embedding its generator than by directly connecting to the grid because the embedded generator is entitled to the benefits under regulations in one case but would have to negotiate receiving them in the other. But the incremental costs of negotiations to achieve this outcome are unlikely to involve any material cost because the parties know there is a regulatory solution that will assure the generator the benefits. Moreover, this situation will arise whether transmission charges are based on 'deep' connection or not.

Furthermore, this small issue with the current TPM could be resolved by making generators entitled to the benefits their connecting brings to local distributors in the form of lower transmission costs whether they embed or directly connect to the grid. This would be a more efficient option than NERA's proposal that generators be denied these benefits when they embed. If these benefits reflect real social benefits, it would be inefficient to regulate that generators do not have access to them when deciding whether or not to invest. For efficiency, the decision maker has to face the true social costs and benefits. This is a basic principle of economics which NERA's proposal neglects.

b) Gumfields: an example

To try to illustrate its argument that the current arrangements will lead to inefficient outcomes NERA outlines in Box 4.1 of its paper an example called Gumfields. This involves a 60 MW wind farm near Kaitaia. Kaitaia, which has a load of 25 MW, is connected to the grid by a long connection asset linking it with Kaikohe to the south. Currently Top Energy, and through it the local load, pays 100% cent of the connection charges associated with the Kaikohe to Kaitaia link. No new transmission investment is needed to link Gumfields to the grid, apart from the actual connection assets required. If Gumfields connects to the Kaitaia grid exit point (GXP) then it will be charged injection overheads by Transpower and, according to NERA, will pick up 70% of the annual shared connection charge, and Top Energy's share would fall from 100% to 30%.

NERA argues that because connecting to the existing connection assets would result in Gumfields assuming a large proportion of the connection charges for the shared assets, the owner of Gumfields may have an incentive to:

- install a much smaller wind farm so as to reduce its Anytime Maximum Injection (AMI)
- enter into an arrangement with Top Energy to build the connection to the GXP
- install a much smaller wind farm and embed it directly into the distribution network, so as to avoid paying for any of the existing line and receiving additional revenue from avoided transmission charges or

- abandon the project as uneconomic.[22]

NERA argues that Gumfields negotiating a favourable arrangement with Top Energy is unlikely because the distributor will not have a strong incentive to reach any agreement. NERA accepts that overall the level of transmission charges is likely to fall because the Anytime Maximum Demand (AMD) will probably be less as now some of the local load will be satisfied by local generation most of the time. However, NERA notes that transmission charges are a 'pass through' for electricity distributors under the price path threshold regime administered by the Commerce Commission. As a result, NERA argues that any reduction in transmission charges will not directly affect a distributor's profitability.[23]

NERA has reached this view, however, because it has failed to take account of two aspects of the New Zealand regulatory regime which are unique to this country. For lines companies the regime is not price or revenue control; it is a price threshold regime. The regime only applies to 'specified services' and goods and services provided when there is workable competition in their provision are not 'specified services'.[24] However, Top Energy would struggle to argue that any agreement it reached with Gumfields was "beyond reasonable doubt" provided in a market with workable competition, even if it won the connection agreement in an open tender against Transpower.

However, provided Top Energy transparently set its charge to Gumfields to recover its costs, including its full costs of capital at an appropriate weighted average cost of capital (WACC), and then even if it breached its threshold as a result, there would be no regulatory consequences. The Commerce Commission is required to administer the threshold regime in a manner consistent with the purpose statement of the relevant section of the Commerce Act. Charges for new services based on efficient prices do not provide a basis for the Commission taking action against a distributor, even if it results in it breaching its threshold.

In addition, the volume variable in the definition of a distributor's notional revenue under the threshold regime is $Q_{i.}$ This is defined to be the base quantity corresponding to the *ith* price in the base year. The Report reproduces this definition.[25] The threshold requirement is that the notional revenue not exceed the base year revenue, after adjusting for any increase in prices permitted for the particular distributor. The base year quantity of a new service introduced during the course of a regulatory period is zero, by definition. So, new services, such as the provision of a connection service to a new generator, are not captured by the threshold. This is not an accident; the Commerce Commission carefully designed the threshold in this manner so it would not discourage distributors from offering new and innovative services, such as connecting new generators. Any new services

[22] NERA, pp. 49 – 50.

[23] NERA, p. 51.

[24] Commerce Act (Electricity Distribution Thresholds) Notice 2004, Clause 3 (1).

[25] NERA, p.51.

introduced during a regulatory period will become subject to the threshold in the next regulatory period, and there could be a price reset if the Commission was concerned about the level of charges for the new service. The Commission was presumably satisfied this arrangement met the purpose statement in the legislation; a view it is hard to argue with.

The Gumfields example not only fails to take account of the unique features of the New Zealand regulatory regime, it is also illustrative of the misunderstanding behind NERA's argument that 'shallow' connection will eliminate problems and be more efficient.

To see this, let us assume that instead of a 60 MW wind farm the proposal was to build at Kaitaia a 250 MW power station and that this would require an upgrade of the line from Kaitaia to Kaikohe at a cost of $85 million. Under NERA's proposal this line would be treated as an interconnection asset, the potential generator would be able to decide whether or not to invest without taking into account this cost of upgrading the transmission line. Under the current arrangements it would be required to factor this cost into its decision making. In our opinion, the current 'deep' connection arrangements are more likely to lead to efficient locational decisions by generators than the alternative 'shallow' connection rules favoured in most instances by NERA.

More generally, where it is possible to identify that a single user or small group of users are the beneficiaries of an asset, it will be more efficient to charge them for use of the asset than it would be to socialise the cost across a wider group, such as load. NERA's apparent preference for 'shallow' connections fails to recognise the efficiency advantage of 'deep' connections; instead it concentrates on what it perceives to be disadvantages of 'deep' connections.

2.4.2 Step changes of costs of shared 'connection' assets

NERA's second objection to 'deep' connection is that the arrangements for recovering the costs of 'shared' connection assets may give rise to significant step-changes in connection charges as 'beneficiaries' change over time, which can reduce certainty and further harm dynamic efficiency .

The first point to note is that increased step changes can only be grounds for criticising 'deep' connection if they will lead to more such changes than the alternative 'shallow' connection arrangement. NERA has not directly addressed this question, but presumably its reasoning is that the deeper the connection the more likely assets will be shared. We are not aware of any evidence that indicates that the adoption of a 'deep' connection asset has led to any material increase in the proportion of connection assets shared, in practice, and NERA has not provided this information either. We have heard there are very few shared connection assets, but this information may be wrong.

The second point to note is that, in practice, off-take customers are unlikely to experience any material step change in connection charges they bear relative to the consumption for which they are responsible, whether or not the basis of charging is 'deep' connection. Transmission charges are a 'pass through' for electricity distributors so they bear no charges at all. Moreover, for charges at a GXP to vary will require a significant change in AMD, AMI or both and/or a significant change in 'market' share at the GXP for the parties that share. Big changes that do not reflect significant increases in consumption are unlikely.

The third point to note is that, in practice, injection customers are unlikely to experience any material volatility in their level of connection charges unrelated to volume changes also. Again, the circumstances that would give rise to big step changes are unlikely. The obvious one is if another generator sharing the GXP ceased production, but that is not going to be a common event.

2.4.3 'First mover' problems

NERA's third objection to 'deep' connection is that the arrangements may give rise to 'first mover' problems, whereby individual generation proponents are unwilling to pay the 'deep' connection charges to connect new generation locations. According to NERA, the deep definition of connection assets means that connecting new generation in remote locations beyond the reach of the existing transmission network may require the construction of 'long spur' lines. This increases the chances that there will be multiple parties wanting to connect in the location over a period of time.

NERA is concerned that:

> *Beneficial investments may be foregone [sic] due to the absence of any formal mechanism to allow the construction of larger assets to new generation location, when smaller links would either be uneconomic, or create scope for potential exercise of market power if built by generators themselves (or distributors).*[26]

As we have already noted in relation to this argument when it was presented in the context of application of the GIT, NERA has overlooked that building transmission connection assets is not a regulated activity in New Zealand. Anyone can invest in such assets – the party being connected, a joint venture of parties interested in being connected, Transpower or any other potential investor. If Transpower builds the asset, its revenue and expenses related to this investment are not covered by its Commerce Commission regulatory regime. The regulatory regime only applies to 'specified services' and since there is workable competition in the provision of connection assets their provision is excluded from the definition of 'specified services'.[27]

The Electricity Commission does not have to approve Transpower's investment either, as only those investments Transpower wishes to have security of revenue recovery for, provided it uses the TPM, need to be approved by the Electricity

[26] NERA, p. 55.

[27] Commerce Act (Transpower Thresholds) Notice 2008, Clause 3 (1).

Commission. Connection assets are usually charged for under a new investment contract between Transpower and the party or parties that will use them.

What NERA is arguing by suggesting that the 'deep' connection arrangement should be replaced by a 'shallow' connection approach is that 'long stringy' connection assets should be treated as interconnection assets and be provided by Transpower, and Transpower alone, and be charged to load. In effect, NERA is arguing that it would be more efficient if Transpower, with the approval of the Electricity Commission, made the decision to invest in 'long stringy' assets and pass the costs and risks of asset stranding and inefficient investment on to load, than it would be to continue with the current arrangement.

At present, the provision of such assets is a contestable activity and investors that decide to provide them bear the risks and reap the rewards of their decisions. There is no reason to believe that an inefficient supply of investments of this kind will be forthcoming. Changing the regime in the manner in which NERA suggest to make Transpower the only party able to invest in such assets would require an expansion of the regulatory regime to which Transpower is subjected. The current regime does not cover the provision of connection assets, but if Transpower is granted a monopoly on this activity then regulations would need to be introduced.

We do not share NERA's view of the comparative efficiency of investment decision making and implementation under socialism and regulatory control. We think the arrangement proposed by NERA for the construction of 'long stringy' connection assets would be significantly inferior to the current arrangement in regard to productive, allocative and dynamic efficiency.

2.5 Treatment of HVDC

2.5.1 HAMI provides poor incentives for peak injection

NERA puts forward three reasons why the locational signal provided by the allocation of the HVDC charge to all South Island generators may be inappropriate. Its first argument is that the historic peak injection parameter (HAMI) which is used to allocate HVDC charges among South Island generators could theoretically provide incentives to withhold supply of peak capacity when this would be inefficient for the economy. NERA notes, however, that the circumstances in which it would be profitable for South Island generators to withhold peak capacity "seem likely to be infrequent".[28] We concur with this analysis and conclude this argument is not a good basis on which to remove the current HVDC charge.

[28] NERA, p. iv.

2.5.2 HVDC charge reduces incentives to invest in South Island

a) LRMC of HVDC compared with charges

NERA's second argument recognises that the incidence of the HVDC charge may reduce incentives to invest in the South Island, particularly in peaking capacity. NERA notes, however, that the deterrence "may well be symptomatic of efficient locational signalling".[29]

We would go further than this. We note the calculations of the LRMC of HVDC transmission capacity that NERA provides in Section 4.5.3, Box 4.4 and Table 2 of the Report. These show that during the period 1999 – 2008 South Island generators should have been levied a charge of $11.42 /MWh on average for use of the HVDC if they were to face the LRMC of the HVDC link and the expansion of it recently approved by the Electricity Commission. This calculation took into account the average spot price differential between the two ends of the HVDC link over the period. The locational signal provided by the current HVDC charging regime was only $6.01/MWh over the period, or $5.41 /MWh too little to be an efficient locational signal. Looking forward, even when the upgrade is charged to South Island generators according to the current methodology, the charge will still only be $10.88/MWh, which is still $0.54/MWh less than the efficient charge.

While NERA notes a number of caveats to this simple analysis, in our opinion, none of these come close to bringing into question the basic conclusion to be drawn from this analysis; the current HVDC charges have, when considered in isolation, been too low to ensure that South Island generators have faced the LRMC of the provision of the HVDC. When the charges increase once South Island generators pay for the recently approved upgrade to the HVDC this will bring the HVDC charge only roughly into line with the LRMC of the HVDC, adjusted for inter-island spot price differentials.

b) Beneficiaries pay

According to NERA:

> *The 'beneficiary pays' concept that has featured prominently in past debates in the charging arrangements for the HVDC link is not a helpful principle by which to determine the incidence of such charges. The concepts of fairness and equity that underpin [the] principle, whilst not inconsequential, should be secondary considerations in any decision regarding the charging arrangements for the link. Rather, the focus should be upon designing a charge [that is efficient].*[30]

NERA has also argued that since the flows of the HVDC link can be both northwards and southwards depending on climatic conditions, beneficiaries pay is not a robust method of allocating HVDC charges.[31]

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[29] NERA p. iv.

[30] NERA, p. 71.

[31] NERA, pp 54-55.

The concept of beneficiaries pay is not underpinned as NERA claims by the concepts of fairness and equity. It is based on observing which parties charges fall on in markets where there is no need for regulatory intervention. It is standard in such markets for beneficiaries to pay. This is for the very simple reason that they have the motive to do so voluntarily. Moreover, by paying for services or goods up to the point at which their marginal benefit from consumption just equals the marginal benefit of what they give up in order to consume, beneficiaries ensure the outcome is efficient. In short, the concept of beneficiaries pay is underpinned by notions of efficiency; the very objective that NERA claims the TPM should be judged against.

Nor is it usually hard at the conceptual and practical level to identify beneficiaries in an economic sense. They are the parties who would voluntarily pay, if paying was the only way to receive the good or service; that is, if there was no opportunity to be a free rider and benefit from someone else paying, then beneficiaries are those that would pay. The extent of their benefit is reflected in the amount they would pay.

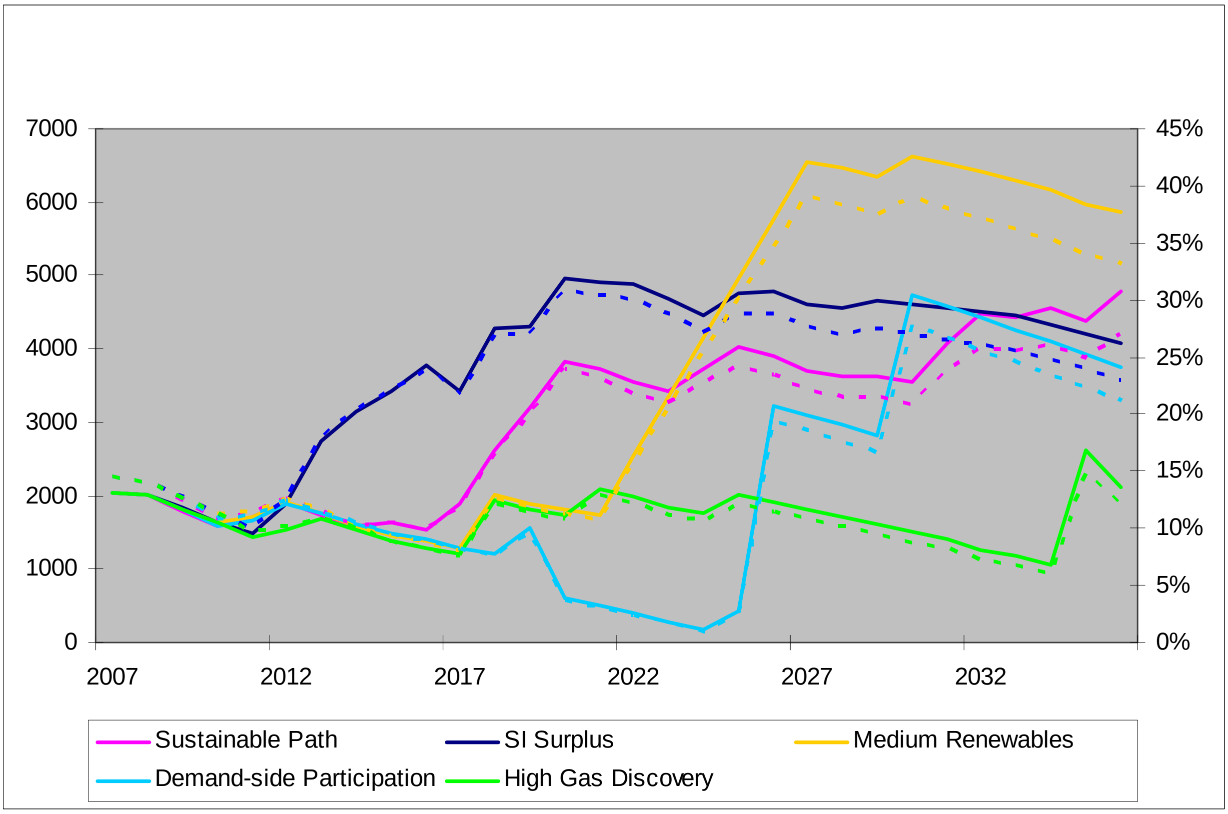
Using this test, in our opinion, the beneficiaries of the HVDC are South Island generators and North Island load, and it is overwhelmingly likely that these parties will remain the beneficiaries for very many years to come. We know that in most years at least some electricity flows from north to south, but the test is if Transpower announced that it would disconnect the HVDC link tomorrow would South Island load and North Island generators pay voluntarily to retain access to it? We think not.

North Island generators would know that the prices they would receive for their output would be significantly higher on average without the HVDC link, even if from time to time it might be convenient to have South Island electricity to meet demand or to export electricity southwards. South Island load would know that the price of electricity would collapse to close to $0/MWh in the absence of the HVDC link. Moreover, they would know that even in dry years, the risks of them facing scarcity would not be as great because without an HVDC there would not have been the prior export of electricity (i.e. stored water) earlier in the year.

As regards the future, as NERA notes, the 2008 *Statement of Opportunities* (SOO) produced by the Electricity Commission contains long-range electricity demand and supply forecasts by region for each of the five market development scenarios it identifies. It also contains a figure showing the forecast net annual south to north HVDC flows under each market development scenario in each year out to 2035. We have reproduced the data in Figure 1 below. The net flows in GWh are shown on the left axis. On the right axis we show the percentage of South Island demand in each year to which the forecast net flows equate. These are the dotted lines in the figure. Although the SOO should not be taken as an accurate forecast of generation capacity, it is the basis for grid expansion evaluation in New Zealand and so a reasonable reflection of likely scenarios for the range of grid expansion plans.

Figure 1 HVDC net northwards transfer

In GWh (LHS) and in % of forecast demand in the South Island (RHS)



Source: Calculated by NZIER from data kindly provided by the Electricity Commission

On this basis, we consider it is overwhelmingly likely that South Island generators and North Island load will remain the beneficiaries of the HVDC link for many years to come. Only under the "high gas discovery" scenario is there not an increase in forecast south to north flows over time and in every scenario and in every year the net flow is forecast to be northwards.

2.5.3 Asymmetry of investment incentives

NERA's third concern about the current HVDC charge is it "increases the likelihood that new investment will be undertaken by established incumbent South Island generators."[32] It demonstrates the basis for its concern in Box 4.3. The demonstration is very curious, however. It actually shows that if the comparison is either Generator A will invest or Generator B will, then there is no asymmetry in incremental HVDC costs between A and B.

For an asymmetric incentive structure to affect the economic efficiency of investment outcomes, the asymmetry has to change behaviour from what it would otherwise be.

[32] NERA p. iv.

If it does not change behaviour, it does not affect resource allocations and cannot affect the efficiency of investment outcomes. If we assume that either Generator A or Generator B is going to invest but not both, then any asymmetry of the incentive structure of the HVDC charges in this situation is irrelevant to the outcome; the generator that it is assumed will invest will invest. If, however, it is either Generator A or Generator B that is going to invest and the market will decide between them, then any asymmetry of investment incentives could affect the outcome and hence potentially the efficiency of the result. But it is in just such a situation that the example in Box 4.3 shows there is no asymmetry in investment incentives. Thus, in cases where there is asymmetry, it is irrelevant to the outcome, as which generator will invest is assumed. In cases where asymmetry would be relevant, there is no asymmetry in the charging methodology.

NERA has managed to identify a problem with HVDC charges where one does not exist for any practical economic purpose related to the efficiency of outcomes. To put it another way, when the decision as to which generator will invest is going to be decided in the market by the costs and benefits each faces, there is no asymmetry in the opportunity cost of the HVDC charges that each faces – they both face the same opportunity cost - and so this will not be a factor in deciding between which of the two generators actually invests.

2.5.4 Merchant transmission

NERA has dismissed suggestions that the HVDC link should be operated as a merchant transmission investment on the grounds that the annual loss and constraint rentals that a prospective operator of the HVDC would anticipate recovering on this basis would be unlikely to cover the annual costs of financing the HVDC.[33]

The HVDC owner/operator receiving the HVDC loss and constraint rentals as its entire income stream is not the only basis on which the HVDC could be operated by a merchant, however. The proposal put forward at the Electricity Commission’s second conference on the TPM was that the HVDC owners should be free to buy on the wholesale market electricity in one island and to sell in the other but, unless there is competition in the provision of the service, they should be subject to a regulatory constraint that over the course of a year they can only earn WACC plus their operating expenses. Rebates to generators from whom electricity was bought would be used to repay any excess returns.

If all flows were from south to north, the economic consequences of this arrangement would be roughly equivalent to the current arrangements, except the economic costs of the HVDC would fall upon the South Island generators that sold at the times when the HVDC was exporting to the North Island. This would have minor efficiency benefits, in itself. More importantly, should there be a need from time to time for north to south flows, the economic costs would shift to North Island generators. This is a clear advantage over the current arrangement. In our opinion, it is regrettable that

[33] NERA, pp. 101-2.

NERA has chosen to ignore the suggestions to it that it explore merchant transmission investment options for the HVDC link.

2.6 Conclusion from NERA's evaluation of the current TPM

- NERA's argument that the LRMC of transmission capacity fluctuates in a cyclical manner over time is incorrect. The practical conclusion NERA draws from this analysis is that that it would be difficult to design a TPM that would provide the correct locational signals. NERA's scepticism about determining a *durable* LRMC of transmission capacity underlies its caution about its own analysis of the LRMC of the HVDC.
- NERA's concerns about the application of the GIT reflect a misinterpretation of the New Zealand regulatory regime as applied by the Commerce Commission and the Electricity Commission.
- NERA's concerns about 'deep' connection are based on applying an inappropriate economic test and its misinterpretation of the New Zealand regulatory regime. NERA fails to show that 'shallow' connection will improve the efficiency of locational signals, and a simple example based on the Gumfields example provided by NERA demonstrates it will not.
- Of the three concerns about the current HVDC charge NERA identifies, it correctly dismisses one itself and it provides very good evidence to dismiss the second. The third concern turns out on close analysis to be illusory for decision making about investment in South Island generation.
- NERA's dismissal of 'beneficiaries pay' is based on a mistaken view of the basis of the concept and how to apply it in an economic sense.
- The data in the SOO relating to future transmission market development scenarios strongly support the conclusion that South Island generators and North Island load are the major beneficiaries of the HVDC link and will continue to be the major beneficiaries for a long time to come.
- NERA has not considered the merchant transmission investment option that has been proposed in New Zealand for the HVDC.

3. NERA's high-level options

3.1 Brief outline of the options

NERA has come up with three high-level options for introducing locational signals into the TPM. These are set out in the table below.

Characterisation of Grid	TPM Option	Key Issues
Structural south-north flow that will drive new investment in that 'highway'	• Tilted Postage Stamp (TPS) methodology applied to generators • Residual charge on load based on RCPD • Shallow connection • No HVDC charge	Is the assumed structural characterisation valid?
'Bespoke' locational preferences, i.e. focus on locations where load patterns are clear or on shorter-term investment requirements	• 'Modified' TPS methodology applied to generators • Residual charge on load based on RCPD • Shallow connection • No HVDC charge	Would the estimated locational signals be sufficiently enduring?
Enduring characterisation not possible	• Retain deep connection • No HVDC charge • Locational signals provided by nodal prices, deep connection and the GIT	Is there a feasible alternative to this 'default' position?

The tilted postage stamp (TPS) option divides the country into seven zones and assumes that Transpower's investment programme is to support the flow of power from the south to the north. Under this methodology, a generator is required to pay a levy based on the estimated incremental cost of the proposed new capacity in inter-zonal transmission for every zone that is to the north of its location. The further south the generator, the higher the levy in general, hence the reference to this being a tilted postage stamp. The charges are 'tilted' north-south. The amount of revenue required for interconnection assets not collected from generators through this TPS levy will be collected from load on the same basis as under the current methodology.

Under this option the HVDC charge is rolled into the tilted postage stamp levy. One corollary is that generators will only pick up the incremental costs of expanding HVDC capacity and not the costs of current capacity, as the TPS levy only relates to incremental investments. North Island generators that currently pay nothing for transmission will, if they are south of Zone 1 which starts at Albany, pay directly for transmission. It is also proposed that the 'deep' connection charge be replaced by a 'shallow' connection charge with the costs of the assets reassigned being recovered from load through the current interconnection charge.

The modified TPS option is based on the assumption that transmission upgrades in the North Island above Whakamaru and in the north of the South Island above Benmore are motivated by shifting load north, but transmission investments elsewhere, including upgrading the HVDC, are not so motivated. Thus, under this option, only generators above Whakamaru but below Albany in the North Island and above Benmore in the South Island will pay a levy to cover incremental costs of inter-zonal transmission investments. The levies will recover the incremental costs of inter-zonal transmission investment assumed to be motivated by a desire to shift electricity north. No generators will pay for the HVDC link. It is also proposed under this option that the 'deep' connection charges be replaced by 'shallow' connection charges and the revenue lost by this be replaced by increased interconnection charges levied on load.

The third option involves retaining the current pricing methodology, including 'deep' connection except the HVDC charge will be rolled into the interconnection charge and recovered like other interconnection charges from load.

3.2 Comments on high-level options

A common feature of all three options is the reduction or elimination of payment by South Island generators for the HVDC with the costs effectively being shifted to load. As we have noted, the Report does not provide a basis for this change improving the efficiency of outcomes. In fact, the Report suggests that the current HVDC charge is inefficient because it is not large enough to cover the LRMC of HVDC transmission.

A feature of two of the options is the replacement of 'deep' connection charges with 'shallow' connection charges for generators and load with the revenue forgone being recovered from load through increased interconnection charges. The Report does not provide a basis for this change either. In fact, an example used in the Report can be extended to demonstrate the change will reduce the efficiency of charges.

4. Conclusion

In our opinion, the current Report is very unlikely to influence any independent regulator to drop the current HVDC charge or 'deep' connection charges and replace them in the manner suggested in the options. This is because these proposals are based on weak analysis and a misinterpretation of the current regulatory regime in New Zealand. An independent regulator will quickly see this once the Report is subject to scrutiny and submissions. An independent regulator will also quickly see the relative inefficiencies of what is proposed compared with the *status quo* we have pointed out in our review.

Release of the current Report is, however, likely to damage the prospects of a consensus about the appropriate TPM for New Zealand. It is likely that some will see the Report as little more than an attempt by several of its principal sponsors to shift costs from themselves to consumers. This is not likely to encourage consensus development.

We suspect that the problems in the report arising from failure to properly interpret the regulatory environment may have arisen because interested parties have provided NERA with information on a confidential basis and their information may not have been correct. If this is the case, then NERA should be careful when reviewing the report to subject confidential information to the most rigorous scrutiny before accepting it at face value.

We believe the Report requires very significant reworking to ensure that it is based on stronger economic analysis and does not reflect misinterpretations of the New Zealand regulatory regime. Only then is the study likely to form the basis for helping form a consensus around how the TPM could and should be amended to the benefit of us all.