2019 issues paper

Transmission pricing review

APPENDICES

Consultation paper

23 July 2019

Appendix C Material change in circumstances

C.1 This appendix sets out how the Authority considers there has been a 'material change in circumstances' as contemplated by clause 12.86 of the Code, enabling the review of the TPM.

There have been material changes in circumstances

C.2 Clause 12.86 of the Code states that the Authority may review an approved transmission pricing methodology if it considers there has been a material change in circumstances.

C.3 The Authority considers that material changes in circumstances have occurred since the TPM came into force in 2008, as set out in this appendix.

C.4 The Authority has outlined these material changes in circumstances in earlier TPM review consultation papers, including in the second issues paper.[294] We summarise this previous assessment here, updated to reflect that the changes in circumstances have become more accentuated over time.

C.5 Since the TPM came into force in 2008 we have identified the following material changes in circumstances to prompt a review of the TPM:

(a) **A significant amount of transmission investment has been commissioned since 2008 and a lot more investment is currently forecast.[295]**

The Authority considers that the current TPM was not designed for the boom in recent – and projected – investment in the transmission network that we have seen since 2008. Poor outcomes that are already resulting from inefficient price signals will only be amplified.

Some submitters to the second issues paper have questioned whether new investment is a material change in circumstances – for example Trustpower questioned, if the current TPM is an efficient way to recover regulated revenues of $500 million, why would it no longer be efficient to recover revenues of $1 billion? [296]

The Authority considers that the inefficient behaviours and outcomes caused by the current TPM will be amplified by the scale of the recent and projected growth of the asset base, and thus the revenues to be recovered.

With rapid growth projected in investment and thus costs to be recovered, it will become more likely that other transmission customers will lose confidence in the current pricing methodology. Poor durability creates uncertainty, harms investment decisions and creates incentives for avoiding charges – which lead to inefficient use of and investment in the grid.

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294 Section 3 of the second issues paper provided our response to issues raised prior to that time as to whether we considered the threshold was met.

295 Transpower's regulatory asset base (RAB) has increased from a value of from $2 billion in 2005/06 to $4.7 billion in 2018/19. In *Te Mauri Hiko* Transpower forecasts a doubling of electricity demand by 2050, much of which will be met by generation connected to the transmission grid. Further, a high volume of investment is expected to be required in Transpower's fourth and fifth regulatory control periods, due to a large number of grid assets requiring replacement and reconductoring as they come to the end of their economic life. Transpower is projecting a very large uplift in total capex in the years after 2025, according to its November 2018 proposal for Regulatory Control Period 3 *Securing our Energy Future 2020 – 2025*.

296 See Appendix C of Trustpower's submission to the second issues paper (pp 67-75) for a critique of each stated change of circumstance considered material by the Authority.

(b) **The increasing range of technologies available to electricity consumers are fundamentally changing the way people engage with electricity markets**.

There have been significant developments in technology and the electricity sector is on the cusp of transformation as a result of new technology. Small-scale distributed generators, batteries, electric vehicles and intelligent energy-management systems provide households, and commercial and industrial consumers with many opportunities that are already affecting the way they purchase, use, produce and trade electricity. The changes that are currently occurring and the future changes are potentially far-reaching and may change the traditional role of the transmission grid, as they will do for local low-voltage networks.

The current TPM pre-dates this period of innovation. Future scenarios include either:

(i) localised electricity networks predominating, reducing reliance on the transmission grid, or conversely

(ii) ,increased demand for transmission services as transport and process heat electrifies.

(iii) The inefficient price signals under the current TPM risk inefficient grid use and inefficient investments (with some customers potentially avoiding or reducing their share of the cost of the transmission grid, without reducing the cost of the grid). A review of the TPM is essential to ensure the TPM can respond to the opportunities and threats posed by new technologies.[297]

(c) **Advances in computational power.**

As we said in 2016, the reducing costs of computational power mean that there are now more sophisticated methods for measuring transmission services and identifying who is receiving those services.[298] We now take improvements in computational power over the last decades for granted, but arguments against reforming the TPM used to include claimed limitations on data and computational power of systems to manage data. Circumstances have now changed and these constraints have been lifted.

Furthermore, we anticipate that enhanced computational power will lead to further market changes, and these will only increase the importance of efficient transmission pricing. Examples include real time pricing, which will sharpen nodal price signals, and demand response platforms.

297 Pioneer submitted in response to the Authority's second issues paper that the Authority should undertake a market study on technology to support its material change in circumstances, consistent with Australian and UK practice. Transpower submitted to our supplementary consultation paper to the second issues paper that careful consideration is needed of the implications of emerging technology, and changes in technology do constitute a potential material change in circumstances. We note various studies and strategies released by Transpower in the last three years document and outline the changes that are occurring and the need for the transmission network to respond to them, including: *Battery Storage in New Zealand* (September 2017); *Te Mauri Hiko – Energy Futures* (June 2018); *Transmission Tomorrow – Our Strategy* (December 2018); and *The Sun Rises on a Solar Energy Future* (January 2019).

298 Trustpower submitted in response to the second issues paper that computational power has no effect on the conceptual issues. For example, it does not mean that it is easier to establish the beneficiaries within an interconnected grid, or that a more complex allocation methodology, enabled by greater computational power, is necessarily superior. We acknowledge the point that computational power should have no effect on the conceptual issues. However, it does affect the practicality and breadth of options available, including conceptually simple solutions, in ways that were claimed to not be possible before.

(d) **The regulatory environment has changed significantly.**

The Authority replaced the Electricity Commission from 1 November 2010, and has a different statutory objective under different legislation from the Electricity Commission. The current TPM was prepared on the basis of guidelines that were prepared and approved by the Electricity Commission given its statutory objective. It is appropriate for the Authority to review and consider whether the guidelines and the TPM best promote the Authority's statutory objective.

Further, since 2008 the function of approving grid investments has been transferred from the Electricity Commission to the Commerce Commission and, over time, the Commerce Commission has modified its rules and processes.[299] It is appropriate to ensure that the TPM is more consistent with, and reinforces, the Commerce Commission's disciplines around transmission grid investment.

(e) **New ambitious climate change Government objectives affect the demand for and use of the grid.[300]**

Over the past few years, the Government has announced a series of new targets to reduce New Zealand's greenhouse gas emissions, including most recently announcing a target to reduce New Zealand's carbon emissions to net zero by 2050. We have not stated this driver directly in previous consultations. However it is a material change that is worth highlighting, given the scale of the economic transition that is being signalled by these new climate change objectives.

In order for New Zealand to reach its targets, consumers of all sizes, from households and small businesses to industrial consumers, will need to turn to grid electricity and other options for low emissions energy.

In this regard we also note the significant change to the operating environment in the electricity sector that has already occurred with the introduction of New Zealand's emissions trading scheme in 2008, and its application to the stationary energy and industrial processes sectors from 2010.

As noted above, this increased demand for energy from renewable resources likely requires an upgrading of the transmission grid. This makes it crucial that prices for using the grid (and of accessing distributed energy sources) reflect economic costs, so that households and businesses have appropriate incentives to make good choices about energy use and energy-related investments.

C.6 Submissions in respect of previous proposals have commented on the materiality of these changes over time, including whether the issues identified above constituted a material change of circumstances and whether the Code's threshold has been met.[301] We note in

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299 For example, the Transpower Input Methodologies Determination was originally determined in 2010 (and reviewed in 2016). The Capital expenditure input methodology (Capex IM) was originally determined in 2012 (and reviewed in 2018).

300 The New Zealand Government has announced ambitions targets to reduce New Zealand's greenhouse gas emissions and in May 2019 introduced the Climate Change Response Act (Zero Carbon) Amendment Bill. In August 2018 the Productivity Commission in its *Low-emissions economy* report noted that electricity will need to meet far more of New Zealand's energy needs to achieve low emissions. Transpower's *Te Mauri Hiko* forecast a potential need to double our renewable electricity supply to allow for greater electrification of major industries and transport.

301 For example, the submissions by Frank Ogilvie for NZ Steel, PowerCo and PWC on the second issues paper considered that the issues identified in the second issues paper (and expanded on in this paper) did not constitute a material change of circumstances. Conversely, others (for example, Meridian, Otago Chamber of

this regard that the threshold is focused on whether the Authority considers that there has been a material change in circumstances. In any event, we have considered the various arguments and still consider that there have been material changes of circumstances since 2008, justifying a full review of the TPM.

C.7 Some previous submissions (including in response to the second issues paper in 2016) have argued that, if a material change to circumstance is identified, then the review scope should be limited to matters relevant to that change. The Authority continues to disagree with this position. The Authority's view is that there is no such requirement or limitation on the Authority's ability to review the TPM once the material change in circumstances threshold is met. The Authority considers that it would be unworkable if the Authority had to demonstrate a link between the circumstances and the proposed change in question. Further, elements of the TPM are interrelated and it would be impractical to review some elements that purportedly relate to changes in circumstances and disregard how the TPM fits together as a whole.

Q49. Do you have any comments on the matters covered in this appendix C?

Commerce and the Otago Southland Employers' Association) thought that the issues we identified in the second issues paper did constitute a material change in circumstances.

Appendix D Elaboration of decision-making and economic framework

Introduction

D.1 Section 15 of the Electricity Industry Act 2010 (Act) sets out the Authority's statutory objective: to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

D.2 In the context of transmission pricing, the Authority has interpreted this statutory objective to mean that the TPM should promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers.[302] This recognises that efficiency and reliability in the electricity industry involve facilitating:

(a) efficient investment in the electricity industry through providing incentives for the most efficient investments to occur at the most efficient time and in the most efficient place. These investments can be in the transmission grid, generation (including distributed generation), distribution networks, or in the demand-side

(b) efficient operation of the transmission grid, generation (including distributed generation), distribution networks, and demand-side management. This means providing incentives for the day-to-day operation of transmission, generation, distribution and demand-side management to involve an efficient trade-off between reliability and cost.

D.3 Efficient investment in the electricity industry primarily relates to dynamic efficiency, while efficient operation primarily relates to static efficiency. The Authority notes in its *Interpretation of the Authority's statutory objective* that, because the Authority's statutory objective requires it to promote the long-term benefit of consumers, the Authority considers that a key focus is to promote dynamic efficiency in the electricity industry, which includes:

(a) taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in the electricity industry, by both suppliers and consumers

(b) taking into account the durability of the industry and regulatory arrangements, including in the face of high impact, low probability events.

D.4 Where a trade-off between static and dynamic efficiency is required, the above statement suggests that significant weight should be given to the promotion of dynamic efficiency.

D.5 In particular, the durability of the TPM arrangements is relevant to promoting efficiency. A more durable TPM is less likely to result in disputes, in calls to fundamentally change the TPM because of various perceived or actual problems with it, and in fewer unproductive changes to the TPM. This would increase efficiency directly, since all of the activities outlined above have real resource costs. As is noted in the CBA, it would also increase efficiency indirectly, since greater certainty for investors about the future shape of the TPM would lead to more efficient investment in the grid, in substitutes for the grid and in related investment. If a new TPM is durable, the efficiency benefits it brings for consumers are also more likely to be enduring.

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302 Interpretation of the Authority's statutory objective, 14 February 2011, available at https://www.ea.govt.nz/dmsdocument/9494-interpretation-of-the-authoritys-statutory-objective-february-2011

D.6 Focussing on overall efficiency means providing incentives for parties to pursue their desired goals at lowest cost to the economy as a whole. This should result in lower electricity prices for all electricity consumers over the long run.

D.7 In 2012 we developed a draft TPM decision-making and economic framework for the TPM review. We consulted on this framework and subsequently published a summary of submissions. Most submitters agreed in principle with the framework, but many raised issues about the application of the framework with some suggesting this implied the framework was unlikely to be practical. We took account of these submissions when we published our paper *Decision-making and economic framework for TPM – decisions and reasons* on 7 May 2012 (DME framework).[303] The Authority has since used the DME framework to guide consideration of the problem definition and to identify options to address those problems.

D.8 The DME framework sets out a hierarchy of charging approaches that we use to identify and assess options for the TPM. The hierarchy gives priority to market-based charges where these are practicable, because workably competitive markets tend to produce more efficient outcomes than other approaches. If market-based charges are not practicable, the hierarchy gives priority to administrative charges, being exacerbators-pay, beneficiaries-pay, and alternative charging options, in that order.

D.9 Submissions on the TPM options working paper continued to express concerns about the practicality of the DME framework. For example, Castalia for Genesis[304] suggested that the DME framework does not provide a tool for assessing options. After considering submissions on the TPM options working paper[305] we took the opportunity to elaborate further on the DME framework in chapter 5 of the second issues paper.[306] Specifically, we elaborated on the relationship between the price signals provided by the TPM and the Commerce Commission's investment approval regime. Our view is that locational marginal pricing (LMP) will, in general, ensure that the use of the grid is efficiently constrained to its capacity. However, even with LMP, inefficient transmission price signals will create an incentive for transmission users to use the grid inefficiently. This could then lead the Commerce Commission to approve transmission investment proposals that are efficient given the use of the grid, but are inefficient overall because grid use is inefficient.

D.10 The conclusion we drew in the second issues paper is that this problem could be mitigated if users were charged appropriately for the full cost of the transmission investment that they benefit from, because they would then take account of the cost of transmission investment to New Zealand when they make their own decisions. Specifically, we concluded that:

(a) transmission prices should, as far as practicable:

(i) recover the cost of delivering the transmission service (ie, be cost-reflective)

(ii) ensure that the cost of the transmission service is charged only to those customers who benefit from the service and in proportion to the benefits that they receive (ie, be service-based)

303 All these documents are available at the following link: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/economic-framework-decision-making/,

304 Castalia. *Transmission pricing methodology: beneficiary pays options*, report to Genesis Energy, March 2014

305 The relevant documents are available at the following link: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15374

306 See chapter 5 of the second issues paper.

(b) the pricing methodology should be practicable and involve reasonable transaction costs.

D.11 Some submitters disagreed with this approach. For example, Creative Energy Consulting (CEC) for Trustpower wrote that fixed charges are unfair and impractical, and that a 'forward looking' LRMC charge is required. We disagree, for the reasons outlined in chapter 5 of the second issues paper and the rest of this appendix. In addition, we discuss further in appendix E why we do not consider that a forward-looking charge is justified.

D.12 Other submitters had more specific concerns. For example, some submitters[307] considered that charging Auckland/Northland is not service-based charging, because they have not in fact seen improvements in reliability and/or quality of supply. Similarly, Entrust considered that service-based pricing is an unhelpful concept, because Auckland does not receive a higher quality of service than other parts of New Zealand. However, our modelling suggests that these areas have in fact benefitted from the pre-2019 investments included in clause 13(b) of the proposed guidelines.[308] Pioneer considered that service-based and cost-reflective pricing will only exacerbate the existing 'economic sizing' issues in the grid. However, as the CBA demonstrates, removing the RCPD charge and relying on nodal pricing allows efficient expansions of the grid, which bring net benefits to consumers.[309]

D.13 Still other submitters on the second issues paper thought that transmission costs should be funded equally by all grid users.[310] For example, PowerCo suggested that transmission costs should be recovered using a broad-based, low level, and non-discriminatory allocation, as this is the least distortionary approach. We do not agree with this, because, as described in the rest of this chapter, we consider that charging users for grid investments that benefit them promotes efficient investment, and that charging users who do not benefit from a grid investment for that investment can cause inefficient behaviour.

D.14 On the other hand many submitters supported cost-reflective and service-based pricing.[311] Some considered it will lead to more efficient investment decisions. Others considered it would promote the long-term benefit of consumers. For example, Stephen Littlechild for Meridian considered that our approach of service-based and cost-reflective pricing is consistent with the characterisation of competition as a dynamic process and that the 2016 TPM proposal promoted dynamic efficiency.

D.15 Having considered submissions on the second issues paper, we remain of the view that the essence of the analysis presented in chapter 5 of the second issues paper is robust.[312] We therefore have not repeated this analysis in this 2019 issues paper.

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307 Air Liquide, Northpower, Top Energy and Vector.

308 See appendix A.

309 See chapter 4.

310 For example, Auckland Federated Farmers, Auckland's Heart of the City, Counties Power , EMA, Federated Farmers, Fletcher Building, Newmarket Business Association, Northland Mayoral Forum, Onehunga Business Association, Refining NZ, Ruapehu District Council, South Harbour Business Association

311 Business Central, Canterbury Employers' Chamber of Commerce, E-Type Engineering, Gore District Council, Grey Power Southland, Invercargill District Council , Market South, Meridian, McIntyre Dick and Partners, Nicholas Brown, Otago Chamber of Commerce, Otago Southland Employers' Association, Preston Russell Law, Sarah Dowie, South Port New Zealand, Southland Chamber of Commerce, Southland District Council, Southland Manufacturers Trust, Stabicraft Marine, Venture Southland

312 The discussion in this chapter is also relevant for distribution pricing. However, a key difference in the context of transmission pricing is the presence of the spot electricity market, as it produces nodal prices that influence the use of the transmission grid. The absence of nodal prices in most of the distribution sector means the efficient structure of distribution prices could differ materially from the efficient structure for the TPM.

Q50.	**Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?**

D.16 This appendix discusses efficient transmission pricing and refines the principles set out in the second issues paper and summarised above. If readers would like a more detailed analysis, please refer to chapter 5 of the second issues paper.[313]

An analogy with workably competitive markets

D.17 The Authority considers that workably competitive markets provide an appropriate analogy for efficient transmission pricing. For the reasons set out below, workably competitive markets are reasonably efficient. As a result, prices for transmission services set on a basis similar to that which results in workably competitive markets will also be relatively efficient.

D.18 The remainder of this appendix outlines how prices evolve in workably competitive markets, why this leads to relatively efficient outcomes and therefore what the principles for efficient transmission pricing should be.

Pricing in workably competitive markets

D.19 In a workably competitive market, a business with fixed costs, such as an airline or a hotel, will endeavour to maximise profitability by charging its customers 'what the market will bear'. This means that the business will aim to supply to any customer who will pay more than the extra costs that supplying them causes (ie, the short run marginal cost (SRMC)), provided it expects to have spare capacity. It also endeavours to charge more when demand is high (such as during seasonal peaks).[314]

D.20 Conversely, a customer will only buy the good or service if it values it at least as much as the business charges for it. This means that the benefit to the customer of accessing the product is at least the price the customer pays for it.

D.21 Although each business tries to maximise profitability by charging what the market will bear, competition between suppliers limits the price that the business can charge for the service. If the business is to survive, it must be able to charge enough to recover the capital cost of its investment, its operating and maintenance costs, and a normal return on capital. If at any point in time, the average price it can realise is higher than this, the excess profits being generated make it attractive for businesses to enter or expand.[315] This entry results in extra competition for customers, which will lead to a fall in the average price each business is able to charge. Conversely, if for some reason efficient businesses cannot make a normal return, some businesses will exit or downsize and the reduced supply will allow the remaining suppliers to realise higher prices.

313 The discussion here implicitly assumes that the price signals from the TPM are passed through directly and unaltered to consumers. We are aware that this is inaccurate. For example, most mass market consumers have fixed-price, variable-volume electricity contracts. However, other sections of this paper (eg, the peak charge section of appendix E) explain why this assumption is innocuous.

314 To be precise, the customer always tends to pay the SRMC of the service, where the SRMC is the resource cost of providing them with the service and the opportunity cost of providing them with the service (in terms of not being able to service other customers).

315 To be precise, an average price (and so SRMC) above LRMC implies that a new investment is likely to recover its full costs, so new investment is justified, and vice versa.

D.22 In other words, competition for customers coupled with entry and exit of suppliers drives excess profits (above a normal return) towards zero and ensures that efficient surviving businesses earn around a normal rate of return.

D.23 This means that in workably competitive markets, prices paid by customers are typically no more than the benefit the customers get from the service and on average equal to the cost of providing the service. This is illustrated by the example of hotel bed-nights given in the box below.

An example of a workably competitive market: the market for hotel bed-nights.

During off-peak times, a hotel will tend to set a price that at least recovers the SRMC of providing the bed and most customers prepared to pay this price will be accommodated. During the peak season, the hotel will raise the price of a bed-night, knowing that there will be sufficient customers prepared to pay the higher price and ensure it has few vacancies.

On the other side of the transaction, if a customer is keen to hire a room during the peak season (ie, the benefit it get exceeds the price it has to pay) it will be prepared to pay the higher price because it knows it has to pay the higher price to secure accommodation. Customers who do not value accommodation as much will not be prepared to pay the higher price and will miss out. This is how prices match the amount of accommodation made available to customers to the available capacity, and allocate (or ration) the available accommodation to those customers who value it most.

This example can be extended to accommodation at both a five star hotel and a one star hotel. The average price of a bed in the one star hotel (at the same time and place) will typically be less than that of the five star hotel. This will reflect the differences in costs of providing a five star hotel bed compared to a one star hotel bed. Some customers will value what a five star hotel offers, and be prepared to pay the higher price. Other customers won’t and will settle for the bed at the one star hotel or will miss out.

As described in paragraphs D.21 to D.25, entry and exit will tend to ensure that each sort of hotel recovers its full cost of operation over time. That is, over time, the supply of each type of bed (five star and one star) adjusts so that that the average price charged for those beds is typically sufficient to meet the full cost of supplying them, and that capacity is broadly matched to demand.

The example can also be extended to deal with hotels of equal quality at different locations. The average price of a bed in a high-cost location will be more than the average price of a bed in a low-cost location, because it costs more to provide.

These propositions demonstrate the general points that:

at any point in time, the price of a service rations demand for the service to capacity, allocating that capacity to the users who value it most, and

over time, the average price of a service reflects the efficient cost of providing the service.

D.24 The result is to ensure customers get the best deal practicable consistent with efficient businesses staying in business.

(a) When demand is high, available capacity is allocated to consumers who value it most. When demand is low, consumers who are prepared to pay at least the costs they generate get access to the product or service.

(b) If capacity is less than can be justified by the expectation of earning a normal return on capital on the last unit of capacity added, the incumbent providers will make excess profits so there is an incentive for providers to invest in new capacity, and vice versa.

D.25 As a result, capacity is driven towards the maximum that can be justified by the return on capital it generates. At this capacity, the benefit that customers collectively get from the services provided by the businesses is at least the cost of providing those services, and the amount of capacity built is around the amount that customers demand, given the prices charged. These arrangements ensure a reasonably efficient outcome.

D.26 One implication is that the way market prices for the services of a particular asset vary over its life will depend on consumers' preferences for the services provided by a new asset compared to an older one. In particular, if customers are relatively indifferent to the age of the asset providing the service (as they are with the hire of a well-maintained trailer, for example), then the charge for the service will be independent of the age of the asset providing the service. The Authority considers that this is the case for transmission investments.

D.27 Another implication is that a business will continue to charge for an investment as long as the investment continues to provide services (and irrespective of the investment's accounting life), because it can find users who continue to benefit from (and so are prepared to pay for) the services provided by the investment. For the business, the gain it makes from being able to sell the services of an asset that lives longer than originally expected will on average be offset by the losses it incurs on an asset that expires earlier than originally expected.

Pricing of transmission services

D.28 We can derive the principles for regulating prices of a natural monopoly investment like a transmission network by analogy with the way prices are set in workably competitive markets. This is because workably competitive markets tend to be reasonably efficient. As a result, regulating prices for transmission services on a basis similar to the prices that result from the workings of workably competitive markets will also be reasonably efficient.

D.29 The High Court's discussion in *Wellington Airport & others v Commerce Commission*[316] (at page 175) supports the view that regulation should try to pursue the outcomes that would result from workably competitive markets. The Court found that: *"We consider that the outcomes produced in better functioning workably competitive markets are, indeed, the ones to be pursued. The fact that such workably competitive markets may depart in many respects from the markets for regulated services, which are not workably competitive, is the very reason to examine them"*.

D.30 In both the case of natural monopolies and workably competitive markets, the approach is to charge each user of the service at each point in time in accordance with the benefit they

[316] *Wellington International Airport Ltd and others v Commerce Commission* [2013] NZHC 3289.

receive, while ensuring that charges are sufficient to fund efficient investment. With workable competition, competitive entry and exit ensures that users collectively tend to be charged no more than the full cost of production of the service and that all efficient investments are undertaken. With natural monopolies, we cannot depend on competition to lead to this outcome. Instead we rely on regulation to pursue the same end.

Efficient charges for connection investments

D.31 Connection investments are used to connect a transmission customer to the grid.

D.32 The discussion above suggests that for such a connection investment, efficiency requires that the customer is charged the full cost of the connection investment. In this case, as with workably competitive markets, we can rely on each customer to assess for itself whether the benefits it gets from the connection investment compensate them for the cost of the investment and for any risks and uncertainties associated with the connection investment.

D.33 In particular, if the customer privately contracts another party to connect it to the grid, the parties will have the incentive to take into account all of the relevant costs and benefits, in the same manner as parties in a workably competitive market. One example of such a contract is a customer investment contract (that is, an unregulated commercial contract) between Transpower and the customer. This is likely to be efficient.

D.34 This leads to our first principle for transmission pricing:

Each user should pay the cost of connecting it to the grid.

Efficient use of and investment in the grid[317]

Efficient use of the grid

D.35 As with workably competitive markets, the price for using the grid should reflect the cost of using the grid. It should rise during peak periods so that grid use is just restricted to grid capacity and so that the available capacity is allocated to those who get greatest benefit from it.

D.36 It is well established that LMPs can serve this role effectively in the transmission network. For example, the International Energy Agency says that "*Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments.*"[318, 319]

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[317] To be clear, in this appendix, we develop principles for transmission pricing by analogy with workably competitive markets because it provides useful insights as to why the principles for transmission pricing established here are appropriate. The principles for transmission pricing discussed here are consistent with the more formal analysis set out in chapter 5 of the second issues paper. They are also consistent with the conclusions of Hogan (2012) and Rivier et al (2013). See footnote 125 for a further discussion of these articles.

[318] See International Energy Agency. (2007). The result was first established by Schweppe et al (1988).

Léautier (2019), section 6.4, makes a similar point:

> Suppose producers face LMPs. Competitive equilibrium capacity in market m is determined by the free entry condition E …. Therefore, competitive equilibrium results in optimal [generation] investment. This is simply an application of a general result in economics: if competition is perfect, equilibrium prices lead to efficient production and consumption decisions in the short-term, but also in efficient investment decisions.

See also William W. Hogan (forthcoming)

D.37 The reason is quite simple. LMPs are set to equal the SRMC of supplying or using electricity at each point of connection to the grid. As with the analogy with workably competitive markets, this is the price that by definition ensures that the resource cost of using the grid is met and that, when there is congestion, the use of the relevant circuits is assigned to the highest value use. It immediately follows that, with certain assumptions (discussed further in appendix E), no other peak charge is likely to be as efficient as LMP in restraining grid use to capacity.

D.38 Although this is now well known, it is only in recent decades that LMPs have been practical, as is discussed under the heading *The historical origins of LRMC-based peak charges* in appendix E. Possibly for that reason, many countries have not implemented LMP and are therefore forced to restrict grid use by implementing some peak-based transmission charge (such as an LRMC-based peak charge). As discussed in appendix E, this is typically less efficient than using LMP.

D.39 New Zealand is therefore fortunate to have a relatively complete implementation of LMP in the form of nodal prices:

(a) The scheduling pricing and despatch model (SPD) incorporates all relevant capacity constraints and despatches generation so as to meet demand while taking account of these constraints.

(b) The resulting nodal prices are generally just high enough to ensure that use of the grid is restrained to capacity and that the short-run cost of transporting electricity over the grid (ie, losses and constraints) is covered.

(c) During off peak periods, the short-run price for using the grid (the difference in nodal prices between nodes, or the ‘nodal transport charge’) is low, reflecting spare capacity.

(d) At peak periods, the short-run price for using the grid is high, so that use of the grid is restrained to its capacity and so that the available capacity is allocated to the most valued use.

D.40 In other words, LMP can fulfil one of the key roles of prices in workably competitive markets. It can restrict the grid use to capacity and allocate that capacity to the most valuable uses. That is, LMP can ensure that, given users’ demand for energy and the available grid capacity, use of the grid is efficient.[320]

D.41 There are a number of qualifications to this conclusion, which are discussed in detail under the heading *A peak charge* in appendix E. For example:

(a) there may insufficient price-sensitive demand or supply at a node to allow nodal prices to match the amount of energy supplied at the node to the amount of load

(b) some customers may not face, and so will not react to, nodal prices

(c) nodal prices may not reflect the full SRMC of grid use

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319 We use the term LMPs when referring to prices which meet this ‘textbook ideal’, and nodal prices when we are referring to how they are applied in New Zealand in practice. In most of the discussion here, we are interested in the cost of transporting energy across the grid (the ‘nodal transport charge’), which is the difference between the nodal price at a downstream node and the nodal price at an upstream node.

320 In terms of the DME framework, LMPs are market-based and so come high on the decision making hierarchy, because they are established by the interaction of buyers and sellers in a workably competitive market

(d) arguably, an additional peak charge may be needed to ensure efficient investment by grid users and so efficient investment in the grid

D.42 The conclusion reached in appendix E is that these qualifications do not undermine the arguments presented here. However, they do suggest it may be efficient to supplement nodal prices with administrative load control and possibly a transitional peak charge.

D.43 In summary, as with prices in workably competitive markets, and once known issues are addressed, nodal prices can generally ensure that grid use is efficiently constrained to capacity.

D.44 An important implication of this is that it allows decisions about additions to grid capacity to be de-linked from load and generation developments. That is, LMP can be used to ensure that grid use is restrained to existing capacity, whatever the decisions of grid users. This will allow decisions about whether to upgrade the transmission network to be made purely based on whether the expected benefits from the transmission investment exceed its expected cost, rather than being prompted by the need to allow for things like unexpectedly high load growth.

D.45 Capacity in this context includes all relevant constraints, such as administratively determined grid reliability standards. This means that provided nodal prices are in general effective in restraining demand as described above, investment to meet grid reliability standards can be deferred indefinitely. As a result, it means that these investments can be deferred until they are economically justified. This means that no transmission investment need be made until the benefits to users of the investment are expected to exceed its cost. Thus the substantial net costs to users of inefficiently early investment can be avoided.[321]

D.46 This leads to our second principle for transmission pricing:

> *Locational marginal prices are generally the best means of restricting the use of the grid to its capacity.*

Efficient investment in the grid depends on nodal prices and transmission charges[322]

D.47 In workably competitive markets the average prices that consumers are charged for a service gravitate towards the (efficient) cost of providing them with the service, so that we can be confident that the investment is efficient.

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321 Of course, because of the lags involved in bringing a new transmission investment into use, the decision to undertake a new investment must be made well before the investment is commissioned, meaning that when the investment is actually commissioned, it will likely turn out to be ‘too early’ or ‘too late’.

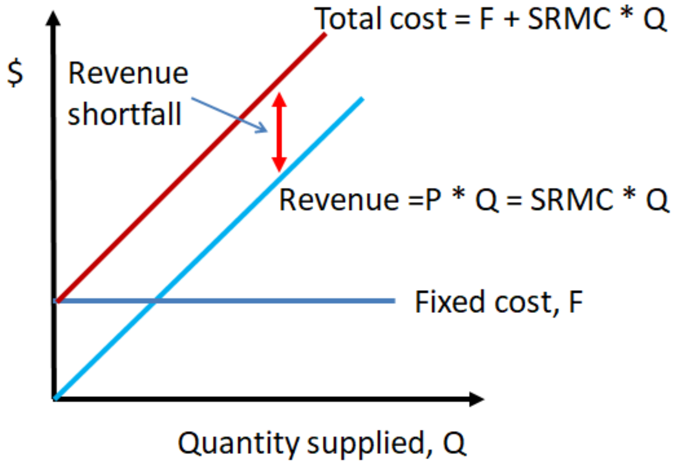
This does not undermine the point being made here that grid investment can be deferred until it is economically justified.

As Hogan (2011) points out, uncertainty like this is inevitable in any commercial investment proposal and must be dealt with (see paragraph B.162).

Nodal prices are beneficial in this regard, as they ensure grid use is restrained to capacity until the new investment is commissioned. They therefore reduce the cost of building the investment ‘too late’ and mean that there is no need to build the investment before the benefits expected from it exceed its cost. (For example it is not necessary to build “early” to mitigate the risk of faster-than-expected load growth).

322 The discussion about investment in this section is consistent with the conclusion in the economic literature on the desirability of marginal cost pricing in decreasing cost industries - see Frischmann et al, 2015. These issues are also addressed in a later and less well known literature on inframarginal economics – see Xiaokai Yang et al 2008.

D.48 However, because there are economies of scale in transmission services, nodal prices[323] are generally insufficient to recover the cost of the investment.[324] This is compounded by the lumpiness of transmission investment.



D.49 This is illustrated by the graph above for a particular case of economies of scale, where there is a fixed cost F of investment (dark blue line) and then a constant per unit cost of production (SRMC = constant – light blue line). Then:

(a) revenue = P * Q = SRMC * Q, where P is the price charged (equal to SRMC) and Q is the quantity supplied (light blue line).

(b) total cost of production = F + SRMC * Q (brown line)

(c) revenue shortfall = total cost less revenue = F (red arrow).

D.50 This means that if we were to rely solely on nodal prices to price use of and access to the grid, users would be charged less than the full cost of supplying them with electricity.

D.51 Charging users less than the full cost of production may lead to inefficient grid investment, as it draws in demand from those customers who would not be willing to pay for it if they were to face prices based on total cost of the investment. Likewise, grid users would also have an incentive to make investment decisions that took into account the nodal prices but not the impact of their decisions on the need for grid investment.

D.52 In the graph above, users would base their decision on the cost they have to pay (the light blue line), even though the cost of supplying them is the brown line.

D.53 In short, customers' decisions are likely to be different from what they would have been had they taken the cost of investment in the grid into account.

D.54 This can be seen from this example: if an investor in a gas fired power station does not take account of their location decision on the need for grid investment, it may locate next to a

323 More precisely, the rentals arising from the nodal transport charge.

324 This is most easily seen in the extreme case where all the costs are fixed and the SRMC is zero. In that case the unit price is zero and the revenue the investment generates is zero.

The general result can be established as follows. Let P denote the use price, let Q denote usage and AC denote average unit cost.

With constant returns to scale, P=SRMC=AC, the firm's total revenue (which is P x Q) equals total cost (which is AC x Q).

By the definition of economies of scale, SRMC < AC. Hence, P=SRMC means P<AC and therefore P x Q < AC x Q. The revenue deficit would equal (AC - P) x Q if access fees were not charged.

gas field even when it would cost less overall if it were to locate near the source of load. Similarly, it may choose to invest in the gas fired power station when it would cost less overall to invest in some other form of generation (eg, solar and batteries) located closer to the load.

D.55 In both these cases, the cost of generation and transmission in total is greater if the user does not pay the cost of transmission, because consumers collectively have to pay the cost of transmission as well as generation. This means that consumers have to pay more overall for electricity because the investor did not need to take into account of the impact of its decision on the cost of transmission.

D.56 As with workably competitive markets, the solution is to ensure that transmission users who benefit from a transmission investment pay the full cost of the investment. This encourages more efficient investment in transmission by ensuring that grid users, in making their investment decisions, take into account the impact of those decisions on the need for grid investment. In the previous example, the investor in the gas fired power station will take account of the fact that if they locate away from sources of load, they may have to pay for a transmission upgrade to support the transmission of energy to the source of load. This means that the investor has an incentive to choose the investment which costs less overall, which means the cost to consumers of electricity is as low as it can be.

D.57 The point is well made by Coase (1970), page 118:

> A consumer does not only have to decide whether to consume additional units of the product. He also has to decide whether it is worth his while to consume the product at all rather than spend his money in some other direction. This can be discovered if the consumer is asked to pay an amount equal to the total costs of supplying him.
>
> [My] rejection of marginal cost pricing [that is, in our context, charging LMP and recovering the costs of transmission through something like the residual charge or general taxation] reflects the view that it is a mistake to concentrate simply on the marginal conditions when examining a proposal. It is the total effect (in which what happens at the margin is only one factor) which matters.

D.58 Furthermore, provided the grid user cannot avoid paying the charge for a grid investment that benefits them (that is, cannot shift their share of the charge on to another user), the charge will also raise the revenue needed to fund the grid investment efficiently. This is because, at the time the decision to invest is made, the benefits of the proposal to users are expected to outweigh the cost. This means that the expected beneficiaries of the investment would have been prepared to pay for it. Therefore, actually charging them this access fee for the grid is unlikely to lead them to disconnect or otherwise inefficiently alter their behaviour. In contrast, other methods of raising the required revenue, such as taxation, are more likely to be inefficient.

D.59 Charging grid users for new grid investments from which they benefit also has the advantage that it will give users with a significant stake in the investment an incentive to engage with Transpower and the Commerce Commission as part of the Commission's investment approval process and to provide information that could otherwise be difficult for the Commerce Commission to obtain.

D.60 If a particular user does not expect to benefit from a particular investment proposal to the extent envisaged by Transpower, it can be expected to provide that information and to oppose the investment when it expects to receive a benefit from the investment that is less than its share of the cost. It may not reveal this information if charges were to be spread across all transmission customers.[325]

D.61 In short, if users are charged for transmission investments, these are only likely to be sustainable where the benefits to users exceed their costs. This check is particularly important in a time of rapid technological change that is improving the viability of alternatives to supply that do not involve expanding the grid.

D.62 The Commerce Commission is charged with ensuring that grid investment is efficient. The Commerce Commission's grid investment approval processes provide a robust method to test the costs and benefits of investment proposals. It is sometimes argued that this negates the need for a transmission charge on beneficiaries of an investment. We disagree. The Commerce Commission's process and analysis provides for transmission investment that is efficient *given* the decisions of grid users. In the case of the gas-fired power station above, it must provide for grid investment *given* the investor's decision to locate the power station next to the gas field. As a result, even if the Commerce Commission's decision is efficient given grid use, it is still the case that outcomes could be enhanced overall by our proposal.

D.63 The analogy with workably competitive markets also suggests how the charges for a transmission investment should be allocated between transmission customers. As discussed above, in a workably competitive market, those who pay most towards an investment are those who benefit most from access to the investment. The effect is that the total cost of the investment is recovered from all those who benefit from it in a manner that ensures the expected benefit each user receives exceeds the charges it faces.

D.64 Likewise, we propose to allocate charges for a new efficient transmission investment in proportion to the benefit that each transmission user is expected to gain from the investment (a 'benefit-based charge'). This would ensure that the total cost of the investment is recovered and that those who pay for it would be expected to realise greater benefits from it than the charges they pay. Importantly, we consider that this is the only allocation method that provides real assurance of achieving this outcome.[326]

D.65 This leads to our third and fourth principles for transmission pricing:

> *The charges for access to transmission services from a new transmission investment in the grid should recover the total cost of providing the transmission investment.*
>
> *Charges for a new transmission investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment.*

D.66 This leaves open the question of the treatment of existing investments. While the arguments are not as clear-cut for applying the benefit-based charge to existing investments, we are of the view that the balance of arguments favours applying the benefit based charge to existing investments for the reasons set out in the following paragraphs.

[325] This point is illustrated in footnote 173

[326] As is discussed further below, this does not mean that those users actually do realise benefits exceeding their charges. As with any investment decision, when the future unfolds, the benefit that any user gets from the investment may be quite different from what was assumed when the investment was undertaken. As is normal commercial practice, this risk would be taken into account in assessing how much each user is prepared to pay for the investment (ie, the expected benefits would be adjusted for risk) and so determining whether the investment should proceed.

D.67 The discussion of workably competitive markets above indicates that where users are indifferent about the age of the investment providing a service, charges for the services of old investments will likely be the same as if the investment was new. This means that the principle for charges for existing grid investments discussed above should also apply to existing investments.

D.68 The reason why this is appropriate in transmission is that if the transmission investment was efficient, it means that the benefits to the relevant grid users are greater than the cost of the investment, so that asking them to pay for the investment will not result in inefficiency. Coase (1970) expresses the point at page 118 thus:

> Apparently, what the advocates of marginal cost pricing [ie, in our context charging users LMP but recovering the costs of investment through some other charge, such as the residual charge or general taxation] had in mind was that the Government should estimate for each consumer whether he would be prepared to pay a sum of money which would cover the total cost. However, if it is decided that the consumer would have been willing to pay a sum of money equal to the total cost, then – and this strikes me as a very paradoxical feature of this argument – he will not be asked to do so. ….I found this a very odd feature. …The way we discover whether people are willing to pay something is to ask them to pay it.

D.69 In contrast, as Coase points out, any other way of recovering the costs is likely to impose efficiency costs. In particular, it means that we would be imposing the cost of the investment on some party that does not benefit from the investment. If we imposed the cost on such a party, this could affect how competitive it is in its product market and so its ability to compete against other potentially less efficient businesses. In the extreme, this might cause them to disconnect from the grid and go out of business.

D.70 Furthermore, charging users in this manner for an investment *after* it is made is necessary to ensure that the efficiency benefits relating to new investments described above are realised. Over time, grid users' behaviour before a grid investment is made will likely adjust to reflect the charges they will face for the investment when it is made. If we do not charge the beneficiaries of the investments the full cost of the investment when it is made, then the behaviour of grid users *before* a particular investment is made will reflect this fact. We therefore consider that the best way to encourage users to take account of the full cost of the investment before it is made is to charge those who benefit from the investment the full cost of the investment when (after) it is made.

D.71 Since on average, generators have to charge prices which recover the cost of their investments, the price they charge for energy will on average be higher than it would be if they did not have to pay the transmission charges. This is no different from saying that energy prices will be higher than they would have been if the generator did not have to pay for one of its production costs, such as the capital cost of its plant. It is simply a result of the charges reflecting the resource cost of supply of electricity, in the manner Coase discusses. It is not clear whether the price at the downstream node would be higher as a result of the generator's higher costs, since it depends on which generator is the marginal generator. What is likely, however, is that the prices at the downstream node will be lower than the prices would have been had the transmission investment not been made, provided the investment is efficient. And, at any point in time, provided the market in generation is workably competitive, the generator's offer will reflect the short run cost of generation and not the transmission charges.

D.72 Furthermore, with benefit-based charges for transmission, as with workably competitive markets, charges will also reflect costs.[327] This means that transmission charges will be higher for generators who depend on more expensive transmission investments. As a result, for example, generation that is remote from load would be expected to pay more over time than generation that is closer. So, if such charges are applied (or had been imposed historically) to all grid investments, load in the upper North Island and generation in the lower South Island may over time have paid relatively high charges. Similarly, remote load that is small would expect to pay relatively more than its size would indicate, both because serving it requires a long transmission line and because it is less able to access benefits from economies of scale in transmission compared with a larger load.[328]

D.73 This leads us to modify our third and fourth principles for transmission pricing so that they refer to both existing and new investments, as follows:

> *The charges for access to transmission services from a transmission investment in the grid should recover the total cost of providing the transmission investment.*
>
> *Charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment.*

D.74 Of course it is possible that past investments were not efficient, either because they were never efficient or because the future turned out to be different from what was forecast at the time of the investment. In principle this could mean there is a difference between the share of benefits that a user actually gets and its share of the cost of the investment. We have allowed for this in our proposal by applying the benefit-based charge only to pre-2019 investments where we estimate the benefit from the investment exceeds its cost.

D.75 However, after an investment is made, the choice a user has is whether or not to use the grid (rather than whether to use the particular investment). So the difference between benefit and cost will not cause inefficiency provided each user is charged at least the additional costs that connecting them to the grid causes and provided the charge is not so large as to make it privately profitable to disconnect from the grid; that is, provided the charges are between the incremental cost of and the stand-alone cost of supplying the customer.[329]

D.76 Typically, incremental cost is small relative to stand-alone cost. This means that, in practice, there is wide discretion in the way that charges for existing investments can be allocated without causing material inefficiency. However, there may be cases where

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327 This also means that it is possible to allocate the cost of the investment to different users according to the cost that is 'attributable' to them. One method that is sometimes advocated for allocating costs is the use of Aumann-Shapley values. In essence, Aumann-Shapley values attempt to ensure that those who contribute most to the cost of a common resource pay most for it. They do so by calculating the marginal cost of adding an additional player to the use of a common resource and averaging over all possible orderings of entry. See Young (1994), page 1220.

We propose to allocate according to benefits rather than attributable costs for the reasons outlined in paragraph D.64.

328 The discussion in this paragraph is accurate if, as with workably competitive markets, charges for an investment continue as long as it continues to provide benefits. For good reason, the Commerce Commission regulatory regime instead allows Transpower to recover just the full cost of each investment. This means in effect that, aside from operating and maintenance costs, charges cease once the cost of the investment has been fully recovered. This creates a tension between applying the principle discussed in paragraph D.78 below and the other principles.

329 For a formal explanation of the rule that charges must be between incremental and stand-alone cost, see Young (1994).

inefficiency is a concern. For example, charges for a small load in remote location (such as the West Coast) may approach stand-alone cost. In that case a prudent discount may be desirable to avoid load disconnecting.

D.77 There is one qualification to this discussion. This can best be illustrated by the following example: Suppose a supermarket found that it was facing the prospect of exiting the market because it was unable to compete with another supermarket, and therefore was expected to get less benefit from a transmission investment than its competitor. Giving the former supermarket a lower transmission charge would be no different in principle from exempting it from council rates because it could not otherwise compete with its competitor. Clearly, this could lead to dynamic inefficiency. It is therefore appropriate to ensure that charges for a transmission user should be similar to other competing users after adjusting for their size and location.

D.78 This leads to our fifth principle for transmission pricing:

> *Charges for a transmission user should be similar to those for other competing users after adjusting for their size and location.*

Q51.	**Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?**

Recovering any additional costs

D.79 There are a number of reasons why the charges discussed above may not fully recover Transpower's recoverable revenue, including:

(a) the charges would not recover Transpower's overhead and unallocated operating expenses

(b) it may not be efficient to recover the costs of some pre-2019 investments using the benefit-based charge, because the efficiency benefits of doing so could be outweighed by transactions costs.

(c) the proposed guidelines would recover post-2019 investments using a different method (ie, IHC) from the method the Commerce Commission uses in setting Transpower's recoverable revenue, with the difference being absorbed by the residual charge

(d) the proposed guidelines would allow various other adjustments to the other charges, with the difference being recovered by the residual charge.

D.80 Again, workably competitive markets provide a useful guide as to how best to recover these costs. In such markets, costs that are additional to short run marginal cost are recovered by having higher charges for those customers who are prepared to pay more than SRMC (ie, whose use is not much affected by paying more than SRMC). Moreover, since nodal prices and the benefit-based charge are sufficient to ensure efficient use of and investment in the grid, the objective in recovering additional costs is to alter users' behaviour as little as practicable.

D.81 In principle, this suggests levying charges on those who are least price sensitive (that is, whose behaviour is least affected by the charges). However, given the practical difficulties involved, such charges are typically levied on the basis of some measure of size and/or ability to pay.[330]

D.82 However we decide to allocate the charge to recover these costs between consumers, it is desirable that the residual charge be designed so that transmission users view it as a fixed charge. That is, it should be designed so that users have no incentive to alter their behaviour to try to reduce the charge they have to pay. The reason for this is that the other charges discussed above ensure each user has an incentive to use the grid and to invest efficiently. This means that if this charge had an effect on the user's behaviour, it would undermine the effect of the other charges in promoting efficient use of the grid and efficient investment. If, for example, the residual charge were allocated based on the user's current use of the grid, that would encourage grid users to inefficiently reduce their grid use below that suggested by nodal prices.[331]

D.83 Paradoxically, it is likely most efficient – and therefore for the long term benefit of consumers – to apply the charge to load only. The reason is that any such charge that is applied to generation (that is, injection into the grid) would largely be passed on to load in the form of higher energy prices, since new generators would then delay entering until the energy prices they expect to receive would cover the residual charge. This means that effectively load customers would end up paying the charge whether or not the legal incidence of the charge is on load or generation. Since the charge would be passed through in nodal prices, it means that nodal prices would be higher, discouraging energy use (compared with the case where the entire charge is on load). This would be inefficient.[332]

D.84 This leads to our sixth principle for transmission pricing:

> *Any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable.*

Conclusion

D.85 This appendix has used the efficiency properties of workably competitive markets to derive principles for the pricing of transmission services that give grid users incentives to behave in ways that ensure efficient investment and efficient use of the grid. This provides grid users with incentives to make decisions that achieve their desired goals at lowest cost to the economy as a whole. This results in lower electricity prices for all electricity consumers over the long run.

D.86 The principles we have derived for the efficient pricing of transmission services can be summarised as follows:

(a) LMP is generally the best means of restricting the use of the grid to its capacity

(b) each user should pay the cost of connecting it to the grid

(c) the charges for access to transmission services from a transmission investment in the grid should recover the total cost of providing the transmission investment

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330 Since general taxation is designed to cause the least practical loss of efficiency, the considerations here are the same as those obtained by following tax policy principles.

331 See, for example, Hogan and Pope (2017), page 76.

332 Economists will recognise this conclusion as being related to that of the seminal article by Diamond and Mirlees (1971) on production inefficiency resulting from the taxation of intermediate goods.

(d) subject to paragraph D.86 (e) below, charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment

(e) charges for a transmission user should be similar to those for other competing users after adjusting for their size and location

(f) any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable.

D.87 These principles need to be applied taking into account ‘real-world’ considerations such as the need to avoid excessive transaction costs.

D.88 In addition, this analysis has made clear the important point that a decision to commission a new transmission investment can be safely deferred until the benefits from it exceed its cost. In particular, a new investment need not be precipitated by such matters as demand growth or grid reliability unless those considerations provide an economic justification for the investment. This means that the substantial costs of inefficiently early investment can be largely avoided.

Q52. Do you agree with the conclusions of appendix D?

Q53. Do you have any comments on the matters covered in this appendix D?

Appendix E Assessment of alternatives

E.1 As part of compiling this issues paper, and as part of previous consultation rounds,[333] the Authority has considered alternative means of achieving the objectives of its review of the TPM, ie, to ensure that the TPM best meets the Authority's statutory objective. The publication of the proposed guidelines does not, itself, result in any changes to the Code, but the guidelines will, if published, likely ultimately lead to a proposal for a new TPM (and therefore Code amendment). Because this current process may result in Code amendments, the Authority has taken the view that it would be helpful to stakeholders to not only provide a CBA at this time, but also provide an assessment of alternatives now as would also be required for a regulatory statement under section 39 of the Act. In this appendix, we provide a description and discussion of some of the main alternatives we have considered.

E.2 The alternatives covered here are:

(a) a peak charge (as part of our current proposal in this 2019 issues paper or some other alternative)

(b) removing the RCPD charge under the current guidelines

(c) a simplified staged approach

(d) a deeper connection charge

(e) a tilted postage stamp charge.

E.3 We focus first on a permanent peak charge, which we have looked at in detail. We then consider the other alternatives outlined in paragraph E.2. We conclude the section with a list of the other options we have looked at as part of past issues papers, and to which we consider the issues and arguments have already been fully canvassed in these earlier papers.[334]

A peak charge

E.4 We have considered in depth the desirability of including a permanent peak charge, such as a long-run marginal cost (LRMC) charge, in the proposed guidelines. In short, our conclusion is that adding a peak charge would not better achieve our statutory objective. Rather, we have come to the view that nodal prices in combination with a benefit-based transmission charge can provide for efficient use of the grid and for efficient investment in the grid and by grid users.[335]

Submitters' views on a peak charge

E.5 Many submitters on the second issues paper[336] thought that the RCPD charge should be retained or some other form of peak charge (such as a LRMC-based charge) should be

[333] See chapter 9 of the 2016 issues paper and chapter 6 of the 2012 issues paper.

[334] Further alternatives, relating to some of the more specific details of the proposed guidelines, are discussed in Appendix B.

[335] As is noted in appendix D, we use the term LMPs when referring to prices which meet the 'textbook ideal', and nodal prices when we are referring to how they are applied in New Zealand in practice. In most of the discussion here, we are interested in the cost of transporting energy across the grid (the 'nodal transport charge'), which is the difference between the nodal price at a downstream node and the nodal price at an upstream node.

[336] They included Air Liquide, Axiom for Transpower, Buller Electricity, Bushnell for Trustpower, Business NZ, Counties Power Consumer Trust , EA Networks, Eastland Generation, Electric Power Optimisation Centre,

included in the proposed guidelines as well as or instead of the beneficiaries-pay charge to promote overall efficiency in use of the grid and efficient investment in the grid and by grid users. The peak charge is argued to be efficient for a number of reasons, including:

(a) it reduces peak demand (eg, by spreading load, reducing demand), deferring transmission investment

(b) it is incorrect to regard the failure to use full capacity as wasteful

(c) nodal prices are not likely to provide adequate price signals, possibly because differences in nodal prices are small compared to the wholesale electricity prices or because consumers do not see nodal price signals

(d) nodal prices are not durable as they are too sensitive

(e) removing the RCPD-based peak charge could have negative flow on impacts for wholesale prices

(f) removing it would disincentivise load management and investment in load management, including in particular domestic controllable load

(g) it helps lower grid security limits

(h) the RCPD charge is consistent with Ramsey principles

(i) the removal of the RCPD charge would involve significant wealth transfers which would have a chilling effect on investment.

E.6 On the other hand, some submitters[337] did not support a peak based charge in addition to nodal prices. The reasons given included:

(a) not having a peak charge would promote competition

(b) having a peak charge risks incentivising inefficient decisions in investment, including inefficient locational decisions, and potentially inefficiently curtailing load during winter peak periods

(c) having a peak charge would over-signal the benefits of distributed generation.

E.7 Different parties who support some form of peak-based charge have either not specified the details or have proposed different variants of a peak-based charge. The key aspects of their proposed approach typically appear to be as follows.

(a) The charge would be a supplementary transmission charge (rather than, for example, a supplement to nodal prices).

(b) The charge would be based on energy use.

(c) The charge would be levied around times of peak energy use. This could be based on the peak in relevant circuits (rather than a regional or system-wide peak).

(d) The peak charge might be imposed at any peak or only around times the circuit would otherwise be congested (either with or without locational marginal prices (LMPs) on the relevant circuit).

ENA, Fonterra, GBC Winstone, KCE, KiwiRail, Marlborough Lines, Molly Melhuish, Network Tasman, Network Waitaki, Norske Skog, Northpower, NZ Steel, NZIER for MEUG, Oji Fibre Solutions, Orion, Pioneer, Powerco, Powernet, PwC for 14 EDBs, Refining NZ, Top Energy, Transpower, Unison , Vector, Waipa Networks, Winstone Pulp

337 For example, Meridian, NERA for Meridian, Mighty River Power

(e) The charge might be set equal to the expected long-run marginal cost (LRMC) of expanding capacity of the relevant circuit in future per unit of use at peak (possibly adjusted for LMP). Alternatively it might be set at a level judged necessary to restrain the use of the relevant circuit to capacity.[338]

E.8 We define a peak charge as a charge that is imposed around peak use of the relevant circuit and that is additional to the benefit-based and residual charges in the proposed guidelines. It therefore encompasses any of the variants described in paragraph E.7. It also encompasses the LRMC charge that the Authority included in the draft guidelines in the 2016 TPM proposal and in its LRMC working paper.[339]

The historical origins of LRMC-based peak charges

E.9 Given the support for the introduction of a peak charge potentially based on LRMC, we have investigated why early advocates of an LRMC charge chose to support it.

E.10 The early debate preceded the academic discovery of LMP and its use as a basis for establishing an efficient market for sale and purchase of electricity across the grid. Nevertheless, this debate followed much of the reasoning implicit in LMP, and discussed use of LRMC-based charges as a less accurate but more practical alternative to what would later be called LMP. The box below provides a short summary of this history.

Our approach to analysing the case for a peak charge

E.11 We have given careful consideration as to whether the proposed guidelines should provide for a peak charge as a core component or as an additional component and whether this would better achieve the Authority's statutory objective.

E.12 For the reasons discussed below, we have concluded that there is a potential case for a transitional peak charge to mitigate possible risks arising from the implementation of the new TPM but that it would not be efficient to have a permanent peak charge and therefore not to the long-term benefit of consumers.

Transpower's report on the role of peak pricing for transmission

E.13 As part of our consideration of the case for a peak charge, we offered Transpower the opportunity to provide evidence as to whether or not:

(a) the removal of the regional coincident peak demand charge (RCPD) charge would have an adverse effect on the ability to meet peak demand

(b) a charge to control peak demand (such as potentially an LRMC charge) would be economically justified if the RCPD charge were removed.

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338 These two approaches are in fact related, if investment in future capacity is efficient. The price necessary to restrain grid use to capacity downstream of the relevant constraint is equal to the short run marginal cost of using energy there. Under certain simplifying assumptions, investment in new capacity is efficient when the average SRMC equals the LRMC of the new capacity. The approaches diverge before load has grown sufficiently to justify new investment, because then the average SRMC is less than the LRMC. See for example Tooth, 2014

339 'Transmission pricing methodology: LRMC charges, published on 29 July 2013, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c13677. While much of the thinking in that paper remains relevant, much of the policy discussion has been qualified or superseded by the discussion in our subsequent publications, including in this 2019 issues paper and in chapter 5 of the second issues paper.

The historical origins of LRMC-based peak charges

Oliver Williamson's paper, Peak Load Pricing and Optimal Capacity[340], sought to determine the optimal price for the transport of electricity as demand increases, and the optimal timing of investment. His optimal price for the transport of electricity is what we would now call the nodal transport charge implicit in LMP (ie, the difference in LMP between nodes).

This analysis was critiqued by Ralph Turvey's paper, Peak Load Pricing.[341] Turvey accepted Williamson's theoretical analysis but criticised it on practical grounds.

The basic notion which he and his predecessors put forward is fully accepted, given his assumptions. This is that the optimum requires price to exceed marginal running cost in periods when demand is high by amounts which will both restrict demand to capacity output in all of those periods and which sums up over them to equal the marginal cost of capacity. In other periods, price must equal marginal running cost.

In modern terms, what Williamson proposed can be interpreted as saying that LMPs should restrict demand to capacity until new investment is justified.

Turvey then goes on to criticise Williamson and others for posing 'ivory tower' solutions that are not practically useful. His critique involves two key elements:

that consumers prefer stable prices but prices in Williamson's analysis would not be stable

that an electricity tariff can have no more than four different prices per year, "except for very large consumers where the expense of recording load hour by hour can be borne".

Both these critiques are no longer valid. Under New Zealand's nodal pricing:

if consumers do value stability in prices sufficiently, retailers have an incentive to provide it through fixed price contracts, which could then be profitable. As is discussed further below, this does not undermine the efficiency benefit of exposing retailers and other parties to LMP.

LMP is feasible and efficient, so there is no need to approximate it with an LRMC based peak charge.

Given the actual conditions in New Zealand today, our view is that Turvey's analysis, as quoted above, indicates that LMP would be what he calls 'the optimum' for pricing the use of the grid – the rationale Turvey advanced for a LRMC charge would no longer apply.[342]

E.14 Transpower responded with the publication *The role of peak pricing for transmission* (Transpower's report).[343]

E.15 We consider that the views Transpower expresses in that report are broadly representative of the views expressed by those who favour providing for a peak charge in the proposed guidelines. Consequently, we provide a detailed discussion of our thinking on Transpower's report and on the desirability of introducing a peak charge of some sort. Our purpose in

340 O Williamson (1966).

341 R Turvey (1968).

342 Of course, the Turvey critique may apply and LRMC based charges may be useful when locational marginal prices are not feasible or practicable. This may be the case for example in imposing a kvar charge to price reactive power or in pricing use of low voltage networks.

343 Our letter to Transpower is included at Appendix A of Transpower, The role of peak pricing for transmission, 2 November 2018, at https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/role-peak-pricing-transmission.

doing so is to clarify our position and to provide a basis for submitters to comment on our views.

E.16 Transpower's report builds on three annexes (annexes B, C and D). We summarise each of the three annexes and then draw conclusions.

E.17 Annex B conducts a literature survey of the responsiveness of electricity demand to electricity prices. We are broadly comfortable with its conclusions,[344] which can be summarised as (page 24 of annex B):

> While it is clear that demand for electricity is inelastic [not very sensitive to prices], the literature remains mixed as to whether peak periods are more elastic than off-peak periods, or vice versa.
>
> High peak-use tariffs tend to reduce peak-time demand, and residential customers are more responsive to peak-time prices than non-residential customers.
>
> Consumer responses to peak-use tariffs are much more pronounced in the long term than in the short term.
>
> Demand response effects are much greater where automated or semi-automated response enabling technologies have been applied. It is reasonable to infer that technological change will result in demand for electricity being more flexible and responsive to price signals
>
> These findings suggest that peak-use charging deters peak-time demand and helps with flattening load profiles.

E.18 Annex C analyses what would happen to demand if the RCPD charge is removed and there is no peak charge to restrain demand, so that distributors withdraw a 'modest' amount of load control (around 3% to 7% of peak demand compared to total load control of 20% of peak demand). It then assesses what this would imply if transmission investment is undertaken to meet this increase in demand. This shows that investment would need to be brought forward by 2-6 years to accommodate the increased demand with 90 percent probability.

E.19 As Transpower says, "The analysis presented in Attachment C demonstrates that absent peak pricing, Transpower would need to invest more, earlier, with the consequence that our transmission charges would be higher".

E.20 We infer that Transpower considers that this investment would be inefficient. This is not necessarily so. Such an investment would be inefficient only if the benefit to users of the additional transmission investment needed to accommodate this increase in peak demand is less than the cost of the investment. Transpower makes the point that this would be more likely to be the case if changing technology means that the new investment becomes stranded before the end of its physical life.

E.21 Transpower states that it "remains firmly of the view [that a] peak price signal is essential to avoid grid overbuild." We agree that some form of a peak price signal is likely to be the most efficient way to avoid grid overbuild (the alternative is to rely on administrative load control at peaks).

E.22 In our view the key assumptions made by Transpower in this annex are as follows:

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344 However, we note that we have made our own estimates of elasticities for different customer classes during peak and off-peak periods in the CBA of our proposal.

(a) the RCPD charge appropriately signals the economic cost of grid use (noting however that Transpower "has been clear that the current peak price for transmission (RCPD) may sometimes be overly strong"[345])

(b) distributors withdraw some load control in response to the removal of the RCPD signal

(c) the anticipated increase in demand would not lead to an increase in the quantity of generation offered downstream of any relevant constraints, that is, all demand would be met from upstream supply

(d) neither demand nor supply is responsive to the impact of an increase in demand on relevant nodal prices

(e) as a result, the only possible responses to the increased peak that would result from the removal of the RCPD charge would be to: build further transmission investment to meet the demand, to impose another peak charge, or administratively control load.

E.23 Annex D of Transpower's report analyses what would happen to nodal prices and potentially system stability if demand for transmission services is increased by the amount of distributor-controlled load at certain nodes that do not have price-sensitive large loads behind them and there is no additional transmission investment to cope with it. Transpower reports that nodal prices at the times of relevant system peaks would rise substantially (6 to 12 times) and that the scheduling pricing and despatch model (SPD) used to schedule despatch and estimate prices would yield infeasible results. This means that some of the SPD constraints would have to be relaxed or some other form of demand control would be required.

E.24 We view the key assumptions in this annex as:

(a) distributors at the relevant nodes withdraw load control in response to the removal of the RCPD signal

(b) the anticipated increase in demand and in nodal prices is not associated with an increase in the quantity of generation offered and available at the relevant nodes

(c) the anticipated increase in nodal prices does not impact on demand at the relevant nodes (ie, the quantity of energy demanded behaves as if it is completely inelastic).

Our conclusions on Transpower's report

E.25 We are of the view that Transpower's report can be used to inform thinking on the desirability of a peak charge, provided that the assumptions underpinning each of its conclusions are taken into account. Specifically, both the analysis of transmission investment requirements in Annex C and the analysis of nodal prices and grid use in Annex D of Transpower's report are incomplete, as they do not take into account the likely response of both demand and supply to higher nodal prices. We consider that it is desirable to take this into account by reconciling the different assumptions in each of the three annexes. Accordingly, we do so qualitatively in the following discussion.

345 Transpower, The role of peak pricing for transmission, 2 November 2018, Page 6, available at https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/role-peak-pricing-transmission

E.26 We conclude that:

(a) demand would likely rise in the first instance if the RCPD charge is removed and not replaced by another peak charge (Annex C of Transpower's report) in part because distributors (or other parties) would likely reduce load control as a result[346]

(b) such an increase in load would (in the absence of another response) necessitate investment in transmission assets being brought forward[347]

(c) however, an expected increase in demand for energy would likely increase nodal prices to the extent there is congestion (as identified in Annex D)

(d) the rise in nodal prices is likely to encourage those exposed to nodal prices to reduce their demand at the relevant node (as discussed in Annex B), and increase supply of energy from generation downstream of the point of congestion

(e) Taking this into account, we consider that:

(i) less transmission will be required than if it was assumed that demand did not respond to nodal prices (as is assumed in Annex C of Transpower's report)

(ii) grid use will be lower than if it was assumed that demand did not respond to nodal prices (as is assumed in Annex D of Transpower's report).

Q54. Do you agree with the conclusions we draw from Transpower's report *The role of peak pricing for transmission*?

E.27 Transpower concludes that a "…peak price signal is essential to avoid grid overbuild." The rest of this section/annex examines this proposition and what that peak price signal should look like.

The nature of a peak charge

E.28 We agree, as Transpower says, that a peak price signal is essential to avoid grid overbuild, to avoid costly administrative load control[348] or both.

E.29 Where we differ from Transpower is in what the peak price signal should look like.

E.30 As is discussed in more detail in appendix D, we consider that it is now well established that, in principle, locational marginal prices (LMPs) can send efficient price signals for optimal short-run use of the grid. For example, the International Energy Agency (2007) says that "Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments."

346 It is not obvious that distributors would reduce load control if the RCPD charge is removed, as is discussed further in paragraph E.51. However, direct connect customers who currently respond to the RCPD charge may increase their demand for energy, although any demand increase would be tempered by higher nodal prices.

347 Transpower's report implies the timing of this investment is inefficient, but as discussed in paragraph E.20, the investment may not be inefficient.

348 Leaving aside transactions costs, with imperfect information on how grid users value load, any peak charge is typically likely to be more efficient than administrative load control in restricting grid use. This is because it encourages grid users to identify and selectively forego grid use which is less valuable to them than the price imposed by the LMP or peak charge. Other parts of this Annex discuss the effect of transactions costs on this conclusion.

E.31 By definition, LMPs are set at the short-run cost of using energy at a particular location, and efficiently constrain grid use to capacity, provided demand and supply are sufficiently price-sensitive there.[349]

E.32 This means that any peak charge that is different from the LMP, and is effective in reducing demand, must be reducing demand or increasing supply at that location more than is necessary to constrain use to capacity.

(a) Although the peak charge may be targeted at reducing demand in periods when the circuit is congested, it has no effect when the LMP would otherwise (in the absence of the peak charge) have been higher than the peak charge. This is because all the peak charge does is reduce the LMP by an equivalent amount, with no effect on use.[350]

(b) The peak charge can only have an effect on use when the LMP would have been lower (in the absence of the peak charge) than the peak charge. In that case, it reduces the use of the grid to below its capacity.

E.33 Since the peak charge imposes economic costs (the cost of foregone demand or increased supply) when using the additional grid capacity is essentially costless, we consider that the peak charge must reduce the efficiency of grid use. As is discussed further below, we consider that a peak charge can therefore only be justified if nodal prices do not fully reflect the SRMC of grid use, or if the inefficient reduction in grid use is offset by some other efficiency gain.

E.34 In principle, therefore, LMP can efficiently restrain grid use to capacity. However, there are a number of other considerations (such as whether it is cost-effective for users to monitor and respond to LMP) which need to be taken into account before determining whether nodal prices are likely to efficiently ration the use of the grid to capacity in practice.

E.35 In practice, therefore, it is an empirical matter whether LMP is sufficient to efficiently restrain use to capacity and whether a peak charge instead of or in addition to nodal prices would improve efficiency.[351] We discuss further below our assessment of this issue.

E.36 We now examine whether there is any reason to suggest that nodal prices complemented by a benefit-based charge are insufficient on their own to ensure efficient grid use and efficient investment, and if so, whether an additional peak charge is required to promote efficiency.

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349 LMPs may not be able to constrain grid use to capacity if energy demand and supply at any node is not sufficiently sensitive to energy prices. We consider that, with the exceptions discussed in this Annex, if LMPs cannot constrain grid use to capacity because demand for and supply of energy are insufficiently price responsive, it is unlikely that they would be more responsive to any other sort of peak charge. In other words, other peak prices have no advantage over LMPs in this regard. They are also likely to be less efficient than LMPs in the restraint they do put on grid use, for the reasons discussed in paragraphs E.32 and E.33.

Rather, if LMPs cannot constrain grid use to capacity, then administrative load control and/or additional investment in the grid would also be required. Administrative load control would be more efficient to the extent that grid users value the forgone energy use less than the cost of the grid investment, and vice versa. In the former case, the benefit-based charge means that the relevant grid users are likely to favour administrative load control since the cost to them of forgoing energy use is less than the benefit-based charge they would pay for additional grid investment.

350 This reduction in LMPs would occur 'automatically' as generators would lower their offer price and load customers would reduce their use of the relevant circuits during periods when they expect the peak charge to be in operation.

351 For example, the transactions costs of implementing LMP in low voltage systems at the ICPs of mass market consumers mean that currently some other form of peak charge is likely to be more efficient. See Batstone et al, 2017.

Are LMPs and a benefit-based charge sufficient to ensure efficient use and investment?

E.37 There are a number of reasons advanced as to why New Zealand's nodal prices and benefit-based charges on their own may not ensure efficient grid use and efficient investment, and why some other price-based measure such as a peak charge may be required. These are:

(a) relevant parties are not exposed to, or do not respond to, nodal prices

(b) nodal prices on their own are insufficient to restrict grid use to capacity

(c) nodal prices, in conjunction with benefit-based charges, may not ensure efficient investment, even though they can restrict grid use to capacity

(d) in practice, nodal prices will not be allowed to rise high enough to manage congestion.

E.38 We consider each of these arguments in turn in the rest of this appendix. In summary, we conclude that there is a potential case for a transitional peak charge. However, in most of the situations where we consider the case for a permanent peak charge, we consider that the case does not stand up.

E.39 The one possible exception is the argument that a peak charge might be needed to ensure that consumers take into account the effect of their own investment decisions on future transmission investment (discussed below as part of the discussion of the issue at paragraph E.37(c)). This may lower transmission costs and so overall costs. However, the conditions that this charge would need to meet lead us to conclude that such a charge is unlikely to improve efficiency in practice and may well be counterproductive.

E.40 We asked Professor W William Hogan to review an earlier paper which is in effect an early draft of this discussion. Professor Hogan replied in a memo dated 31 May 2018. In it, Professor Hogan looked at the desirability of applying a LRMC based peak charge in practice. We provide selected extracts from Professor Hogan's memo in the box below entitled *Professor Hogan's views on the desirability of a LRMC charge.* He concluded his memo as follows:

> Improvements in the analysis and allocation of the costs and benefits to make better decisions and provide better information would be important. This is a separate subject under the general heading of 'beneficiary pays' cost allocations that we have discussed. But the argument that LRMC is available as part of that package 'does not stand up'.

This analysis by Professor Hogan reinforces the more detailed analysis presented here.

Are all relevant parties exposed to and do they adequately respond to nodal prices?

E.41 There are several reasons to consider that relevant parties may not respond, or may not respond adequately, to nodal prices.

E.42 Households and other small consumers are typically not exposed directly to nodal prices. Typically, these consumers enter into fixed-price variable-volume contracts for their electricity with retailers. Since these expose retailers to price risk, they are likely to cost consumers more on average than spot price contracts. The fact that consumers choose these contracts over (likely cheaper) spot price contracts and that retailers find this profitable means that these arrangements are likely to be efficient.

Professor Hogan's views on the desirability of a LRMC charge[352]

The problems of the LRMC story are fundamental. I would step back from the details of the analysis to emphasize three issues. First, the LRMC analysis typically adopts the relevant description of the transmission system is a single line between two points where the flow on the line is driven by the peak load at the destination. Second, the transmission expansion cost function is essentially well-enough-behaved to be approximated by an increasing marginal cost, e.g. convex. Third, transmission customers are myopic and make their long-lasting investments in future consumption equipment based on the current price.

While these assumptions simplify the framework and almost dictate the need for something like LRMC pricing, the assumptions are not innocuous. If we abandon these assumptions to consider something closer to reality, then the case for LRMC falls away.

The most important lesson we have learned over the many years of studying restructured electricity markets is that the interactions in a complex, interconnected, high-voltage transmission grid have a first-order effect on operations and on the marginal cost of dispatch to meet load at any moment. This fact gives rise to the security-constrained, economic dispatch with nodal pricing as found in the New Zealand market design. … Often the intuition that guides the analysis of a single line is simply wrong in the case of an integrated grid. And using the single line analogy to assign transmission costs leads to perverse behavior. ...

The assumption that the transmission expansion cost function is well-behaved enough to allow marginal analysis to guide efficiency is both critical and wrong. ... Hence, there is an inherent contradiction in making the efficiency arguments for LRMC based on marginal analysis precisely when the marginal analysis does not apply; or in making arguments for LRMC using assumptions which make LRMC unnecessary.

Finally, the assumption of myopic loads and one-part pricing seems unnecessary and wrong. It may be true for some customers, who may also tend to be price inelastic and therefore not much affected by the pricing model. But for large volumes at the margin, that could come from larger commercial and industrial loads, the myopic assumption seems too extreme. …The real challenge is in providing information about the counterfactual and the likely future charges with and without the transmission expansion, rather than imposing on everyone the mandate to be myopic.

Improvements in the analysis and allocation of the costs and benefits to make better decisions and provide better information would be important. This is a separate subject under the general heading of "beneficiary pays" cost allocations that we have discussed. But the argument that LRMC is available as part of that package "does not stand up.

E.43 In this case, it is likely that retailers will endeavour to manage that risk by entering in to a contract with a counterparty (such as a generator), so that the price risk is shifted to a party that is better placed to respond to nodal price variations.

E.44 This means that, even though the mass market consumer does not respond to nodal prices, the behaviour of other parties compensates for this so that grid use responds as if they do.

E.45 Even if relevant parties are exposed to nodal prices, it may be that there are barriers preventing them from acting in response to those prices. In particular, nodal prices are

[352] Extracts from the memo from Professor Hogan to Carl Hanssen dated 31 May 2018.

volatile and not finalised in real time, and the transaction costs of responding to prices may be too high.

E.46 Under current nodal pricing, nodal prices are volatile and are not finalised until after the relevant transactions have taken place. Price-sensitive parties will respond to their expectation of prices – the concurrent 5-minute real time indicative prices normally provide a good indication of final prices. However, the actual prices may be significantly different, particularly at times of system stress. As a result, it cannot be guaranteed that demand for use of a congested circuit will be restrained by the nodal price.

E.47 However, we do not consider this to be an argument for peak charges, as, in our view, they don't solve this problem efficiently. They are harder to set to restrain grid use to capacity, since they must be set administratively in advance and are unlikely to be revised on a near real-time basis (or even every half-hour by half-hour).

E.48 If either the time delay could be eliminated or the volatility reduced, that would enable parties to more efficiently respond to nodal prices. We expect that real time pricing (RTP) [353] will eliminate the time delay and mis-pricing by making sure that the nodal prices are known at the time that the transaction occurs.

E.49 It may also be that it is not cost-effective for some consumers to respond to nodal prices. That is, the savings involved from monitoring and responding to nodal prices mean that it is not worth consumers doing so. If this is true for nodal prices, we think it is likely to be equally true for a peak charge.

E.50 At the moment, distributors can use administrative load control to reduce all relevant consumers' load and so mitigate the transactions costs issues of consumers responding individually to a peak charge. They have an incentive to respond to the current RCPD charge because they pay transmission charges. However, as Transpower notes, distributors are not exposed to nodal prices. Transpower therefore appears to consider it likely that distributors will respond to the removal of the RCPD based charge by (potentially abruptly) reducing load control.

E.51 We agree that this risk is real[354], but consider it overstated for the following reasons.

(a) Distributors are likely to have some incentive to act in the best interests of their customers. In particular, some distributors are consumer trusts which can be expected to take into account the interests of consumers connected to them.

(b) It seems likely that the time of a distributor's peak will tend to be correlated with the time that relevant transmission circuits are congested. In that case, distributors may control load on the circuit as a by-product of managing their own networks.

(c) With the introduction of RTP, distributors will have some incentive to bid demand control into the market (as some currently do with interruptible load).

E.52 Furthermore, we know that, overall, demand is, to varying degrees, responsive to prices. We have seen some large industrial firms responding to the RCPD transmission charge by,

353 Details of the real time pricing project are available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/

354 It is a potential risk because an abrupt increase in load may cause challenges in managing the grid, as discussed in Transpower's report, and because it may lead to a greater need for administrative load control, as discussed in Transpower's report and in footnote 349. The increase in load may nevertheless lead to an increase in efficiency, including efficient investment in the grid, as discussed in paragraph E.20.

for example, shifting their load to off-peak periods and installing DG. This is reflected in the estimates of price elasticities in Transpower's report discussed above.

E.53 More importantly, we are expecting to see increasing demand response. First, businesses like Enernoc are already providing demand response services and we expect (and are taking policy measures to facilitate) technology, new business models and other innovation to increasingly allow consumers to behave as if they are actively monitoring and responding efficiently to nodal prices.[355] In particular, we expect over time:

(a) retailers and other aggregators to manage small consumers' load for a share of the nodal price savings that it generates

(b) improving technology (eg, increasing cost-effectiveness of battery technology and information technology) is likely to make it easier for consumers to respond to changing nodal prices, including through automated services that reduce transaction costs of responding to changing prices in real time.

E.54 As Annex D of Transpower's report states, 'demand response effects are much greater where automated or semi-automated response-enabling technologies have been applied. It is reasonable to infer that technological change will result in demand for electricity being more flexible, and responsive to price signals'.

E.55 Second, we are intending to implement shortage prices in the RTP project, which will encourage transmission customers to bid demand control into the electricity market.

E.56 Thus we consider that there are several reasons to expect that households and other consumers' load will become increasingly responsive to energy prices over time. This will likely also lead to nodal prices becoming less volatile and so more predictable.

E.57 In summary, we can see some reasons for caution in the short term about removing the RCPD price signal, with these concerns abating over time as: distributors' behaviour is revealed, RTP beds in, retailers and other aggregators take steps to manage small consumers' load, and various other innovations make it easier for load to respond to nodal prices.

Are nodal prices on their own sufficient to restrict grid use to capacity?

E.58 In principle, LMPs are the most efficient prices for restricting grid use.

E.59 However, nodal prices in the NZ electricity market do not meet this ideal. Aside from the reasons discussed in paragraphs E.41 to E.57 above, the most plausible reason that nodal prices will not restrict grid use to capacity is that they do not fully reflect the SRMC of use of the grid. For example, as discussed in chapter 5 of the second issues paper, nodal prices currently do not fully reflect scarcity prices.

E.60 This provides a plausible argument for a peak charge to buttress the signal given by nodal prices.

E.61 However, since we already have nodal prices (and so incur their ongoing administrative and compliance costs), we consider that a better response is likely to be to address the source of the problem, which is an inadequacy in nodal prices. This is likely to be more efficient, both because (as is discussed earlier), it is better targeted than a peak charge and because

355 Over time, these responses are likely to increasingly compete with distributor's own load control with consequent benefits to consumers.

the additional administrative and compliance costs are likely to be lower than those for an additional new charge.

E.62 Addressing the current deficiencies in nodal prices is a key objective of the RTP proposal.

Q55. Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?

Do nodal prices that restrict grid use to capacity ensure investment is efficient?

E.63 Although LMP may be the most efficient prices for restricting grid use, overall efficiency also requires that investment is undertaken efficiently.

E.64 The Commerce Commission regulatory regime is designed to ensure that grid investment is undertaken efficiently, given the demands that users place on the grid.

E.65 Several parties submitting on the second issues paper considered that a LRMC charge would encourage efficient investment, possibly by encouraging more efficient use of the grid.[356]

E.66 In general, we disagree, for the reasons discussed in appendices B and D. In summary, the proposed benefit-based charge is designed to charge grid users for new grid investments in proportion to the benefits they get from the investment. This is intended to promote efficient investment by grid users, by encouraging them to take account of the impact of their own use and investment decisions on the cost of new grid investment. It also encourages grid users to seek new investment in the grid when it is efficient, and to participate in the Commerce Commission investment approval process.

E.67 However, there is one situation where this approach may not provide incentives for efficient use of the grid and efficient investment. This situation can be seen by considering the situation where there are multiple beneficiaries of a future grid investment, with each grid user being small in the sense that its own decisions do not much affect the timing of or need for grid investment.

E.68 In that case, if grid users could coordinate, they might collectively agree to make current investment decisions that increase their own costs but more than compensate for that by reducing the need for or deferring the timing of future grid investment. That is, they would co-optimise their own investment decisions with grid investment decisions.

E.69 However, if they can’t coordinate their investment decisions, each user will realise that its own decisions cannot much affect the grid investment decision. Each user will therefore take the grid investment decision as given (pre-determined), and optimise its own investment given its forecast of that grid investment decision and the associated future energy prices. This decision may well be different from the decision the user would have made had it been able to coordinate its decision with those of other grid users, as discussed in paragraph E.68 above. This is the so called ‘tragedy of the commons’ situation

356 For example, ENA, Oji Fibre Solutions, Orion, Transpower.

identified by Transpower in its earlier submissions (for example, Axiom for Transpower[357]), and which is implicit in the Transpower's report (footnote 343).[358]

E.70 In this circumstance, it is possible that imposing a peak charge on each grid user over and above nodal prices may encourage each grid user to take account of their decisions on the timing of grid investment and so in effect coordinate their use of the grid. In other words, the charge could potentially have the same effect with respect to grid investment as LMP have in coordinating grid use. This is our understanding of the reasoning of those who favour a 'forward-looking' LRMC charge for use of the grid.

E.71 While we accept that there is a theoretical case for such a charge, we think that there are more considerations to take into account in setting the peak charge than the LRMC of the future transmission investment. The box *'Tragedy of the commons' related incentive problems* below discusses these other considerations in the context of a particular example of the 'tragedy of the commons' problem.

E.72 Taking account of these other considerations would likely mean that the optimal peak charge to co-optimise users' investment decisions with grid investment would be less than LRMC, would vary over time, might reduce as the time for efficient new transmission investment approaches, and might be negative.

E.73 Setting a peak charge which takes account of all these considerations would seem to be at best complex and difficult. Even if LRMC can be estimated robustly, it does not seem practical to establish how big the peak charge should be and when it should apply. On the contrary, there is a very real risk of getting it wrong in ways that reduce efficiency below that which would be achieved without any such charge. Such issues would need to be overcome to establish the case for a peak charge better meeting our statutory objective.

E.74 These conclusions are reinforced by the practical considerations that Professor Hogan refers to in his memo summarised in the box above.

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357 Axiom, Economic review of second transmission pricing methodology issues paper: a report for Transpower, July 2016.

358 A related concern is that small consumers are exposed to nodal prices but don't accurately anticipate them so they make long-lived investment decisions which will eventually cause congestion and higher prices, but they do not take that into account because they do not know that this will happen. As is noted above, in most cases small consumers are likely to be on fixed price contracts which in effect price in average nodal prices and shift the price risk to more sophisticated parties that can be expected to take these considerations into account. However, even if a consumer does face nodal prices, and naively predicts that the nodal transport charge will be about zero (as it is when the relevant circuits are not congested), they will be making a reasonable prediction, since that will be true once a congestion-relieving transmission investment has been made.

‘Tragedy of the commons’ related incentive problems

The tragedy of the commons problem can be illustrated by considering a single user of a transmission investment[359] who is considering whether to expand its plant now (which would require an immediate transmission upgrade) or to defer expanding until next year (which would allow the transmission upgrade to be deferred for a year).[360] We assume that the user is rational and bears all the relevant costs and benefits of the transmission upgrade.

Because the user alone affects the timing of the transmission investment by its investment decision, the user has the incentive to take account of all relevant costs and benefits in making its decision on when to expand its plant (including the reduction in nodal prices and the loss of LCE caused by the transmission upgrade). That is efficient.

This is no longer the case where there is more than one user. This can be seen by considering the case where there are multiple ‘small’ users.[361] In that case, each user takes account of its proportion of the same costs and benefits as the single user. In particular, because it faces the benefit-based charge, it takes account of the cost of the transmission investment in the same manner as the single user. However, there is one key difference. The user correctly assumes that its energy use decision does not influence the timing of the transmission investment. The user forecasts when the transmission investment, if any, will take place and then treats that time and the associated benefits and charges as a given (pre-determined) in its own decision making. As a result, the user’s private calculation differs from that of the single user in the previous paragraphs. In particular, it will not take account of:

(a) the present value of the savings that would result from deferring the transmission investment if users collectively deferred their plant expansion[362]

(b) the benefit from increased energy use that the user would get from an earlier expansion of the transmission investment[363]

(c) associated changes in LMP and LCE.

That is, the users’ investment decision involves different costs and benefits, which could cause the sum of individual users’ decisions to deviate from the efficient decision that the single transmission user would make. This is an example of the”tragedy of the commons” problem.

The annualised value of the term in (a) above is around the (annualised) LRMC of the investment. So, ignoring (b) and (c) above, if we charged the users collectively a variabilised annual charge equal to LRMC for the use of the grid, then each user would take that into account in its decision about whether to expand its use of the grid. This would give the user

359 For the purposes of illustrating the point, we are ignoring the fact that a transmission investment used by a single user would likely be a connection investment.

360 The relevant user in this situation is the person who actually bears the charge. In the case of a price-controlled distributor, the users are the distributor’s end users rather than the distributor.

361 By ‘small’, we mean that each user’s use is small relative to the aggregate use of the circuits involved. For ease of exposition, we assume all these small users are the same. Even if the users are larger, there will still be the same kind of inefficiency discussed here, but it will be less marked.

362 Note however that the small user does have an incentive to take account in its decisions of the fact that its cost of transmission will increase when the transmission investment takes place, since it pays the benefit-based charge for the investment (and users collectively pay the cost of the investment).

363 Each user would face a counterfactually higher LMP where the transmission build is deferred a year, which would restrict its use of energy, so that users collectively optimally restrict their use of the circuit to capacity.

an added incentive to defer its plant expansion so as to avoid the LRMC charge on its expanded use of electricity.[364] This would help overcome the 'tragedy of the commons' problem with respect to (a) above. That is, imposing a LRMC charge would incentivise each small user to in effect take into account the present value of the deferring transmission costs in making its investment decisions.[365]

However, there are some other issues to be taken into consideration. These are that:

- LMPs will rise as the relevant circuits become congested, which already encourages users to reduce their use of the relevant circuits.
- The prospect of a benefit-based charge for the new investment already provides an incentive for the user to reduce their use of the transmission asset.[366]
- There are also costs to deferring grid investment that the user does not take into account (ie, the foregone energy use in point (b) above).[367]
- LMP should ration grid use to the available capacity, and so if a peak charge is effective in reducing grid use, it will inefficiently reduce grid use below capacity, as discussed in paragraphs E.32 and E.33 above.
- An LRMC peak charge cannot be set to send efficient signals about the benefits of deferring grid expansion to both short- and long-lived investments that users might make. For example, suppose an LRMC peak charge is imposed early enough that it is able to provide users incentives relating to the benefits of deferring grid investments when they make long-lived investments. Then it would over-signal with respect to short-lived user investments, because many such short-lived investments would be fully depreciated before the transmission investment is made (and so the investments would be inefficient). The opposite would be the case if the LRMC peak charge was targeted at short-lived investments.

All these considerations would likely mean that the optimal peak charge to co-optimise users' investment decisions with grid investment would likely need to be less than LRMC, would vary over time, might reduce as the time for efficient new transmission investment approaches, and might be negative.

Q56. Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?

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364 Since it is not important to the discussion, we do not pursue here the question of the optimal way of sharing the LRMC charge between users. Our view is that the discussion in appendix D would provide a useful way of considering this issue.

365 This rationale for an LRMC charge is quite different from the arguments advanced by the authorities who initially proposed an LRMC charge, as discussed above.

366 That is, the user will recognise that its charge for the future investment will be proportional to the benefit it is assessed to get from the investment, which will give it an incentive – other things being equal – to reduce its use of the relevant circuits so as to reduce its future charge. This is efficient to the extent it reduces the cost of future grid investment by encouraging the grid user to permanently reduce its grid use (eg, if it encourages the user to install more energy efficient equipment). However, it is inefficient if the saving in charges is different from the grid costs saved or if the grid user is temporarily changing its use to give a misleading impression of its likely future grid use. The proposed guidelines require Transpower to design the TPM to limit these inefficiencies as far as is reasonably practicable.

367 The benefit the user gets from earlier expansion is near zero when the circuit is uncongested and (ignoring LMP and LCE) rises to around LRMC when the investment is justified.

Would nodal prices be allowed to rise high enough in practice?

E.75 As well as the issues discussed above, we have considered a number of other issues relating to the possibility that in practice, nodal prices do not or cannot rise high enough to reflect the impacts of additional demand on congestion, and a peak charge might therefore encourage more efficient grid use.

E.76 The first concern is that **when grid capacity is limited, administrative load control may be used to manage congestion**, even though nodal prices, if they had been allowed to operate, may have been sufficient to constrain the use of the grid to capacity.[368]

E.77 Under current arrangements, the effect of this would be to reduce nodal prices even though the consumers whose load is controlled may value the use of electricity foregone at more than the nodal prices that actually eventuate. In this situation, it might be better to control load with a peak charge, since that could induce a reduction in demand or an increase in supply where capacity would otherwise be constrained.

E.78 With RTP, this issue will no longer arise. The intent is that under RTP, administrative load control would take place only when scarcity prices have been triggered. Thus, nodal prices would signal the loss of use caused by administrative load control. This is likely to be more efficient than a peak charge, because:

(a) nodal prices would signal the cost of administrative load control only when that load control is actually necessary.

(b) the prospect and actuality of high nodal prices is likely to trigger additional energy supply and demand response, reducing and potentially eliminating the need for administrative load control.

E.79 The second concern is that **high nodal prices will cause the public to lose confidence in the sector and are therefore not a sustainable approach to signalling costs of use**. However, fluctuations in nodal prices are not new. There have been high and volatile nodal prices in the past driven mainly by energy costs. As is noted above, many small consumers choose to shelter themselves from price volatility by entering in to fixed-price variable-volume contracts, and it is likely that this practice will continue. Furthermore, with the introduction of the benefit-based charge, sophisticated users who are subject to high and volatile nodal prices arising from transmission constraints will be aware that the nodal prices are expected to cost them less on average than inefficient transmission investment to forestall them.

E.80 The third concern is that **users may never see the full costs of their actions because investment is usually triggered 'early'**, before nodal prices have risen to levels commensurate with signalling that additional investment would be beneficial.[369]

E.81 In particular, one view is that the grid reliability standard (GRS) is an administrative standard that may require Transpower to propose and the Commerce Commission to approve investments that would not pass a cost-benefit analysis and therefore are inefficient. It might be thought that a peak charge is desirable to defer such investments until they are efficient.

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368 As discussed in footnote 349, it may be efficient for the system operator to undertake some administrative load control if the relevant parties are not sufficiently sensitive to prices.

369 Hogan and Pope (2017) make the point that this occurs in the Texas electricity market. Their conclusion is similar to ours: that is, the rules should be adjusted so that transmission investment does not take place inefficiently early.

E.82 If this were so, a better solution may be for us to amend the GRS so that it takes account of the all the economic benefits and costs (including reliability) of such investments.

E.83 However, if this is not practical, at least in the short term, a peak charge could be used to restrict grid use to avoid breaching the reliability standard and triggering the investment until it is economically justified. This would have the effect of turning the administrative GRS into an economic test, since it would mean that use of the relevant circuits would be constrained to capacity by the peak charge until the investment is justified by the reliability and other benefits that it provides.

E.84 Furthermore, the beneficiaries of the investment would have an incentive to support such a peak charge, since it means that the investment would be deferred until the expected benefits to them from the investment exceed the benefit-based charges they would pay for it.

E.85 However, any administrative rule that would otherwise result in inefficiently early investment can be included as a constraint in SPD. The result would be that nodal prices would rise to reduce grid use to avoid breaching the administrative rule. Since nodal prices can generally constrain grid use to capacity, and since they can be supported by efficient load control (as discussed in footnote 13) transmission investment need not be undertaken inefficiently early. Furthermore, LMP would be more efficient than a peak charge, since they would ensure that load is reduced only when needed and only to the extent needed to avoid breaching the GRS.

E.86 If despite this, a decision was made to undertake a transmission investment inefficiently early, it would point to flaws in the transmission investment decision-making process and not to flaws in nodal prices. Accordingly, the appropriate policy response would be to adjust that process.

E.87 Overall, therefore, we see no reason why nodal prices cannot manage congestion efficiently, so practical considerations do not justify the introduction of peak charges.

Q57. Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?

Conclusion: A permanent peak charge?

E.88 In summary, our view is that nodal prices, enhanced by RTP, are the most efficient pricing tool for limiting the use of the grid to capacity. In most circumstances they are likely to be as effective as, and more efficient than, any other peak charge, in doing that.

E.89 This does not preclude the possibility that it may be efficient to operate some administrative load control as well, at least in the short term.

E.90 However, we expect that technological developments, new business models and other innovations will mean that load becomes increasingly responsive to nodal prices over time and responding to nodal prices will become cheaper. This is likely to make nodal prices less volatile, to flatten load profiles and to make nodal prices increasingly effective in restraining grid use to capacity, so that administrative load control is needed much less frequently.

E.91 The Commerce Commission’s regulatory regime is designed to promote efficient grid investment given grid use, and the benefit-based charge gives transmission users an incentive to take into account the cost of transmission investments in making their own investment decisions.

E.92 As is discussed above, there is a potential case for incorporating a permanent selective peak charge for restraining grid use below capacity so as to promote efficient investment by grid users; that is, to deal with the 'tragedy of the commons' issue. However, in practice, such a charge is not likely to improve efficiency once other relevant considerations are taken into consideration.

E.93 As a result, on balance we do not consider there is a case for a permanent peak charge in the TPM to assist in limiting grid use to capacity, or to promote efficient investment. We have therefore not included a permanent peak charge in the proposed guidelines.

Transitional issues

E.94 We do, however, see possible reasons for caution in the short term. These reasons include:

(a) Distributors may respond to the removal of the RCPD transmission charge by abruptly reducing or stopping load control at peaks, unless they are given some incentive to continue with load control.

(b) The expected benefits of RTP in making nodal prices transparent in real time, in stimulating demand response and in limiting premature administrative load control may take time to emerge and may not emerge as expected.

(c) Technological developments (eg, batteries and automated demand control technologies) and market based arrangements (eg, the emergence of demand aggregators) to make mass market load more responsive to nodal prices will take time to become important.

E.95 We consider that a transitional peak charge may be an appropriate and proportionate response to these concerns. Accordingly, we have included an additional component in the proposed guidelines providing for a transitional peak charge.

Q58. Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?

We have considered other options

Addressing RCPD charge problems in a manner consistent with the current guidelines

E.96 Under this option the TPM would be reformed in a way that is consistent with the existing guidelines. This could occur if Transpower decided to undertake an operational review of the TPM to remove the RCPD charge. It could also occur through the Authority's review of the guidelines (for example, if we made the guidelines more restrictive in a way that required Transpower to reform the current RCPD charge).

E.97 A large number of submitters to the second issues paper and supplementary consultation paper supported retaining the status quo or revising the TPM under the current guidelines in some way (though not necessarily removing the RCPD charge. For example, some suggested amending the number of periods over which the interconnection charge is calculated, if the interconnection signal is too strong).[370]

E.98 The Authority considers that variations that are consistent with the current guidelines would be lawful, practicable, and would recover Transpower's costs.

E.99 Because the RCPD charge can reduce use of grid circuits even when they would not be congested in the absence of the charge, the RCPD charge results in inefficient use of the grid.

E.100 In the CBA, we have considered retaining the current pricing methodology but with RCPD required to be calculated using all trading periods so that the RCPD charge becomes a MWh charge. A charge based on load is likely to have a similar effect to a small sales tax on energy sales. It is therefore likely to substantially ameliorate the inefficiency caused by the RCPD charge. As a result, this option is likely to be more efficient than the status quo.

E.101 However, the cost of new investment would continue to be spread across all transmission users. This means that the beneficiaries of a new investment would not face their share of the cost of the investment. As a result, users would have an incentive to ignore the impact of their own decisions on investment and on use of the grid. This means that it does not achieve the various efficiency gains resulting from the benefit-based charge, as described in appendix B. For example, a new investor in generation would not take into account the effect of where they locate on the need for new transmission investment. As a result we consider that this option is likely to be materially less effective than our current proposal at addressing problems with the status quo.

E.102 This reasoning is consistent with the results of the CBA, which shows that replacing the RCPD charge with a load-based charge is more efficient than the current TPM (net benefits of $1.8 billion) but less efficient than our current proposal ($2.7 billion, within a range of $0.2 billion to $6.4 billion).

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370 For example, the following parties supported this option: Air Liquide, Alpine Energy, Aurora Energy, Buller Electricity, Centralines, Counties Power, Counties Power Community Trust, EA Networks, Eastland Network, Electra, Employers and Manufacturers Association (Northern), ENA, Girdwood Consulting for Trustpower, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Newmarket Business Association, Ngawha Generation, Northland Inc, Northland Mayoral Forum, Northpower, NZ Steel, Oji Fibre Solutions, Onehunga Business Association, Orion, Otago Chamber of Commerce, Pacific Leadership Forum, Pioneer Energy, Powerco, Powernet, PwC for 14 EDBs, Refining NZ, Scanpower, South Harbour Business Association, TECT, The Lines Company, Top Energy, Trustpower, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, and Westpower.

E.103 For these reasons, the Authority prefers our current proposal in this 2019 issues paper to addressing RCPD charge problems in a manner consistent with the current guidelines.

A simplified staged approach

E.104 This option was described by Transpower in its submission to the second issues paper.[371] It was also supported by a number of submitters on our supplementary consultation paper.[372]

E.105 Under this option, the TPM guidelines would require a TPM with several different charges, implemented in stages:

(a) a simplified benefit-based charge payable by load applying to most existing interconnection assets to replace the RCPD charge.

(b) the simplified benefit-based charge be recovered as a peak charge that is LRMC-like (based on use) and designed to promote efficient use of grid assets that are not connection assets

(c) a continuation of the existing HVDC charge[373]

(d) a fixed residual charge to recover Transpower's remaining recoverable revenue.

E.106 In addition, it would include as additional components to be implemented if justified:

(a) a non-simplified benefit-based charge applying to new investments over a certain threshold

(b) the replacement of the HVDC charge with extended locational prices for generation.

E.107 This option would potentially also include some of the optional features of the proposal put forward in this 2019 issues paper.

E.108 A key feature of this option is that it could be implemented in stages.

E.109 As is discussed above, we are of the view that a peak-based charge, in addition to nodal pricing would likely detract from efficiency. Instead, therefore, we analyse the proposal with the peak based charge replaced with a fixed charge based on some form of proxy for benefits.

E.110 In addition, we consider the proposal including the additional component related to the HVDC charge. We assume that this would be allocated to generation customers on some basis that is not related to their current or future use of the grid, because otherwise it would inefficiently affect their use of the grid. With this proviso we consider that the proposal would better reflects the long term costs of providing transmission services to generation, and is therefore likely to improve efficiency.

E.111 We first consider the proposal without the additional component relating to the non-simplified benefit-based charge.

E.112 The Authority considers that this revised simplified staged option is lawful, practicable, and would recover Transpower's costs.

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371 Transpower's submission is available at: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15999.

372 For example, this option was supported by the following parties: IEGA, NZ Energy, Pioneer Energy, Otago Chamber of Commerce, Mercury, and Genesis Energy.

373 This is not clear, but appears to be implied on page 6 of Transpower's submission on the second issues paper.

E.113 We also consider that the simplified staged approach is simpler and would likely have lower implementation costs than our current proposal.

E.114 However, we consider that this option is likely to be less effective than our current proposal at addressing problems with the current TPM. In particular it is likely to be less efficient than our current proposal in relation to non-HVDC costs. This is because the beneficiaries of an investment would not face their share of the cost of the investment. The proposal would therefore not achieve the key benefits identified in Appendix B from having a benefit-based charge. In particular, grid users would make their own use and investment decisions without taking account of the impact those decisions have on grid investment. For example, a new investor in generation would not take into account the effect of where they locate on the need for new transmission investment.

E.115 For this reason, we consider that it would be desirable to implement the additional component relating to the benefit-based charge as well as the additional component related to the HVDC charge.

E.116 We consider that, provided the area over which benefits were calculated was relatively granular, this option would provide load customers with a charge that better reflects the long-term costs of providing transmission services to them, and is therefore likely to improve efficiency, relative to the current TPM.

E.117 However, we are of the view that it would not be as efficient as the proposal set out in appendices A and B. This is because:

(a) Generation customers would face none of the cost of new transmission investments from which they benefit. As a result, the various benefits outlined in appendix B from applying the benefit-based charge to transmission customers would be foregone for generation customers.

(b) Load customers would face the full cost of transmission investments, even though it is likely that generation customers are likely to benefits to some extent from the investment. This could result in various inefficiencies. For example, load customers may oppose an investment that is efficient overall.

(c) The benefit-based charge would only apply to major investments. This means that load which benefits from the investment would pay for all of a major investment but potentially only a small proportion of a non-major investment that is only slightly smaller. This sharp boundary could create various inefficiencies, as discussed in appendix B.

(d) It would only partially address the problem that beneficiaries of post-2019 investments would be asked to pay for those investments while being asked to continue to pay for the pre-2019 major investments that benefit others. Our view is that this will create durability problems, as discussed in appendix B.

(e) The broad regional approach proposed for existing investments would create boundary issues and potentially consequent implementation difficulties.

E.118 All these issues could be mitigated by adjusting the details of the policy. However, we consider that these adjustments would move the policy towards the policy described in Appendices A and B of this issues paper.

E.119 For these reasons, we prefer the proposal in this 2019 issues paper to the simplified stage approach.

A deeper-connection charge

E.120 The Authority considered this option in detail in the second issues paper. Under this option, the new TPM guidelines would require that the interconnection and HVDC charges be replaced by a residual charge and a 'deeper-connection' charge. This option is similar to our current proposal, but with a deeper-connection charge instead of benefit-based charge.

E.121 The deeper-connection charge would be calculated by:

(a) determining the concentration of load users and generation users of an asset, based on electricity flows[374]

(b) using those concentration values to determine the total deeper-connection charge, if any, to be allocated to load and generation for the asset

(c) allocating the deeper-connection charge for the asset based on physical capacity or share of flows (for load), and share of flows (for generation).

E.122 The Authority considers the deeper-connection option is lawful, practicable, and would recover Transpower's costs. We also consider it is likely to be more efficient than the status quo. In particular, customers would have stronger incentives to take account of the impact of their own decisions on investment and on use of the grid. This means that it would achieve some of the various efficiency gains resulting from the benefit-based charge, as described in appendix B. This is because the main parties paying a deeper-connection charge for an asset would be aligned with the parties receiving transmission services from the asset. For example, transmission customers liable for the deeper-connection charge for a new investment would have stronger incentives to scrutinise transmission investments than they would under the current TPM, where the costs of an investment are spread across all load in the case of interconnection and South Island generators in the case of the HVDC. We consider this would lead to more efficient decisions by transmission customers in relation to their use of the grid.

E.123 However, there are disadvantages to this option that are less likely to arise under our current proposal. In particular:

(a) customers who pay the deeper-connection charge may be charged more than the benefit they receive. The charge could be designed to minimise the chance this would occur (for example, by excluding assets from the charge where this is likely to occur, and by allowing assets to be 'optimised'). However, some distortions are likely to be inevitable

(b) the deeper-connection charge is likely to be less effective at promoting efficient investment. In particular:

(i) it would only partially recover the costs of most assets

(ii) it would not apply to some assets at all, even though the beneficiaries of those assets may not be particularly difficult to identify

(iii) it would be poor at promoting efficient investment in new large assets, as the charge would be poorly aligned with the distribution of benefits from such investments. This is because the addition of large assets to the grid can materially alter power flows over other parts of the grid (altering the deeper-connection charges for those assets). It can materially alter nodal prices around

374 The concentration indicator would be the Herfindahl-Hirschman Index, a commonly used measure of concentration.

the grid, but the deeper-connection charge ignores the benefits that arise from those pricing effects even though they would be benefits that users would be prepared to pay for

(c) the identification of deeper-connection assets and the parties subject to the charge is quite complex and is likely to result in distortions to behaviour. In particular, the proposal to periodically review the charge, while having the benefit of ensuring charges remain somewhat service-based, has the disadvantage of creating incentives which encourage grid users to inefficiently alter their grid use. The Authority would seek to design the charge to minimise such distortions, however some distortion is likely to remain

(d) the deeper-connection charge creates a locational distortion for distributors, generators, and direct-connect transmission customers

(e) the deeper-connection charge is likely to result in higher transaction costs than the current proposal.

E.124 We prefer the proposal in this 2019 issues paper to the deeper-connection charge because of the disadvantages of the deeper-connection charge that are set out above.

A tilted postage stamp charge

E.125 Under this option, the new TPM guidelines would require that the TPM consist of a connection charge, and an interconnection charge and HVDC charge set on postage stamp basis, but with the rate of the charge varying between regions. The 'tilt' of the charge, or the distribution of charges to different regions, would be set with reference to the long-term cost of providing transmission services to different regions (or an approximation of that cost). A tilted postage stamp option was supported by several submitters to the second issues paper and the supplementary consultation paper.[375]

E.126 Various versions of the tilted postage stamp proposal have been proposed. One variant of the tilted postage stamp option would be new TPM guidelines that require the TPM consist of a connection charge, an LRMC charge and a postage stamp residual charge. The combination of the postage stamp residual charge and the LRMC charge would provide the 'tilt', ie, the differential in charges between regions.

E.127 We consider here a charge which is not related to customers' energy use and under which the cost of new investment is recovered from all designated transmission customers in proportion to their existing transmission charges. While different versions of the tilted postage stamp proposal would have different efficiency effects, the direction of the effects identified below would be the same relative to the current TPM and relative to the current proposal.

E.128 The Authority considers the tilted postage stamp option is lawful, practicable, and would recover Transpower's costs. We also consider it is likely to be more efficient that the status quo. This is because:

(a) it better reflects the long term cost of providing users with access to the grid, and so encourages them to take account of those costs in making their decisions

[375] For example, the following parties expressed support for this option: CEC for Trustpower, EA Networks, and Trustpower,

(b) it avoids charging customers based on their energy use, and so largely avoids creating an incentive for customers to inefficiently alter their grid use to reduce their transmission charges.

E.129 However, this option is likely to be less effective that the current proposal at addressing the problems identified with the current TPM. The main reason is that it does not align the charges transmission users pay for new investments with the costs of those investments. This means that it does not yield the efficiency gains expected from the benefit-based charge, as set out in appendix B. For example, it is likely to lead to inefficient investment and grid use by transmission customers and so grid investment that may be efficient given grid use, but is inefficient overall.

E.130 The Authority considered and did not favour this option when we prepared our second issues paper.[376] On further consideration, we have not changed our assessment of this option compared to the current proposal.

We have also considered, and do not favour, a range of other alternatives

E.131 During the course of earlier consultations and in earlier issues papers, the Authority has considered a range of other options for reform as well as the status quo. Some of the options considered are:

(a) several options proposed by the TPAG (2011)[377]

(b) ten options considered in the Authority's first issues paper (2012)[378]

(c) four different types of beneficiaries-pay options considered in the beneficiaries-pay working paper (2014)[379]

(d) the LRMC charging options considered in the LRMC working paper (2014)[380]

(e) three options considered in the TPM options working paper (2015)[381]

(f) two alternative options considered in the Authority's second issues paper (2016) (that is, an SPD-based charge and a broad-based, low-rate charge for each island or four transmission pricing regions combined with a broadly levied HVDC charge)[382]

E.132 We do not prefer any of the options listed above relative to the current proposal for a variety of reasons, including either because they are not lawful, are not practicable, deliver lower net benefits, or would not further the Authority's statutory objective. On further

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376 Further analysis of the option is presented in paragraphs 9.28 – 9.34 of the second issues paper.

377 The Transmission Pricing Advisory Group (TPAG) was an ad hoc advisory group established in 2011 to recommend a preferred transmission pricing option. The TPAG's report is on our website: https://www.ea.govt.nz/development/advisory-technical-groups/disestablished-groups/transmission-pricing-advisory-group-2011-disestablished/.

378 The first issues paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c2119. Alternative options are considered in chapter 6.

379 The beneficiaries pay working paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c7492.

380 The LRMC working paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c13677.

381 The TPM options working paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15374.

382 The second issues paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15999.

consideration, we have not changed our assessment of these options discussed in the earlier papers.

Q59. Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?

Q60. Do you have any comments on the matters covered in this appendix E?

Appendix F Potential changes to the Code

F.1 In this appendix we set out three potential Code amendments that we consider to be consistent with the Authority's TPM guidelines proposal (including potential drafting of the Code amendments).

F.2 These changes would be to:

(a) amend Part 14 of the Code to specify a methodology that Transpower must use to allocate loss and constraint excess (LCE)

(b) amend Part 6 of the Code to adjust the avoided cost of transmission (ACOT) provisions to be consistent with the proposed guidelines

(c) amend the Code to allow the Authority to further review an approved TPM if its implementation is found to be unworkable or if it has been implemented in a manner inconsistent with the Authority's policy objective.

F.3 These potential Code amendments logically accompany our proposal to amend the TPM guidelines. The first two in particular would be consequential to the adoption of the proposed TPM guidelines. While we are minded to propose these amendments in the near future, because these Code amendments are linked to adoption of the proposed guidelines and a consistent TPM, we are not proposing that the Code be amended at this stage.

F.4 Rather, we present the Code changes now to encourage comment on our proposal as a whole. Subject to consideration of feedback, we would consult again on whether to adopt the Code changes (if they are still considered necessary) alongside any future proposed TPM developed by Transpower.

Potential Code amendments and discussion

Code change 1: LCE amendment

Description[383]

F.5 Amend the Code[384] to provide that:

(a) a grid owner must allocate any LCE (including residual LCE) it receives in a year:

(i) amongst investments in proportion to the LCE generated by each investment (including investments whose cost is recovered through the residual charge); and

(ii) in respect of each investment, amongst customers in proportion to the transmission charges they pay in that year in respect of that investment.

(b) this allocation is deemed to be the prevailing methodology for distribution of LCE payments for the purposes of the benchmark agreement.

[383] We asked Transpower about the workability of these proposed code amendments. As part of its commentary on this, Transpower indicated that it considered that it would be more efficient for the clearing manager to allocate LCE for FTR settlements to the FTR manager, and residual LCE directly to purchasers, and that it had submitted this to the Authority's consultation in March-April 2019 on its *Proposal for the design of the remaining elements of real time pricing* (refer: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972). We will be considering that point as part of that consultation.

[384] Refer to the proposed Code amendment drafting annexed to this appendix.

Discussion

F.6 As discussed in appendix D, workably competitive markets provide a natural analogue for establishing efficient pricing in the interconnected grid. If the market for grid investments were workably competitive, owners of grid investments would charge users the SRMC of transporting energy across individual grid circuits, and the resulting nodal transport charge (the difference between nodal prices at the ends of the circuit) would tend to both efficiently ration the grid circuit to its capacity and provide the owner of the grid circuit with a normal return on capital.

F.7 Likewise, nodal prices are set in the spot market and generate a financial surplus. The surplus on a circuit in any trading period is approximately the difference in prices between the two nodes of the circuit during the trading period multiplied by the amount of energy that flows between the two nodes during the trading period. These surpluses are used to create a pool of funds called the LCE.

F.8 However, unlike in workably competitive markets, the nodal transport charge yields insufficient revenue to cover the cost of the investment. This is because transmission exhibits economies of scale, as is discussed in footnote 324. As a result a second charge is necessary to recover the transmission owner's total costs.

F.9 Nevertheless, as paragraph F.6 above notes, the nodal transport charge is the natural analogue to prices in workably competitive markets. The resulting LCE is generated through the operation of the wholesale market for electricity, and therefore is preferred to administratively determined charges as outlined in the Authority's DME framework.[385]

F.10 However, the benefit-based charge is intended to recover the total covered cost of the investment. If Transpower were also to receive the residual LCE for the investment, it would recover more than the expected cost of the investment, and transmission users who benefit from the investment would collectively pay more than the expected cost of the investment. This is inconsistent with what would tend to happen in workably competitive markets, because in those markets excess profits tend to zero as new entrants take advantage of the excess profit opportunities.

F.11 Instead, in order to best seek to mirror the workings of a workably competitive market, the residual LCE from an investment needs to be assigned to those who pay charges in relation to the investment, so there is no over-recovery from customers. This can be achieved by crediting the residual LCE generated by each transmission investment to the Transpower customers who pay transmission charges in relation to the investment.[386] In particular, Transpower would credit:

(a) LCE generated by each connection investment to the customer or customers who pay connection charges for that investment.

(b) LCE generated by each benefit-based investment to each customer who pays a benefit-based charge for the investment in proportion to the share of charges they pay for the investment.

(c) LCE generated by investments whose cost is covered through the residual to customers that pay the residual charge, in proportion to the share of the residual charge that each customer pays.

[385] Electricity Authority, *Decision-making and economic framework for transmission pricing methodology – decisions and reasons*, 7 May 2012.

[386] The economic effect of this treatment is similar to that of the treatment proposed in Hogan (1991).

F.12 There is one qualification to this. Before Transpower receives the LCE generated by the grid, clause 14.16 of the Code requires that some of it is first used by the FTR market and the balance remaining after that process is transferred to Transpower for use as LCE. It is this sum that would be allocated by Transpower as described in the previous paragraph.

F.13 The Authority considers that the potential Code amendment is efficient because it parallels the workings of workably competitive markets by ensuring that customers pay charges in relation to an investment that are expected to recover the full cost of the investment, and it avoids cross-subsidisation of other investments. As explained in appendix D charges which best parallel those in workably competitive markets are likely to be efficient.

F.14 Under our potential Code amendments, because the allocation method specified in the Code would be Transpower's 'prevailing methodology' under the Benchmark Agreement, no amendments to the Benchmark Agreement would be required.

F.15 LCE payments do not reduce the amount of transmission costs recovered under the TPM, but LCE payments offset transmission customers' individual transmission charges. This means that the incentives for customers are the same as if LCE payments did reduce the amount of transmission costs recovered under the TPM. So transmission users effectively face nodal prices and the benefit-based charge net of LCE.

F.16 This means that load that stands to benefit from lower nodal prices as a result of a proposed investment would assess the extent to which the benefits from lower nodal prices and a greater volume of electricity transported exceeded the reduction in LCE. Similarly, generation that stands to benefit from higher nodal prices as a result of a proposed investment would assess the extent to which the resulting benefits from higher nodal prices and the greater volume of electricity transported exceeded the reduction in LCE.

F.17 We therefore expect that transmission customers would only support the investment where they expect that the net private benefits from changes in electricity prices and volumes would exceed the transmission charges they would incur and the LCE they would otherwise receive if the investment did not proceed.

F.18 Consider, for example, a benefit-based investment that is expanded to cater for the growth of one load customer but which would also supply another load customer whose demand is static. The investment would benefit the customer whose demand is growing as they would be able to receive increased volumes of electricity as their demand grew. Taking into account LCE prior to and after the investment, they are likely to receive net benefits from it, and therefore be willing to pay for it, because any reduction in LCE resulting from the investment would be more than offset by the benefits they would receive from lower prices and the volume of electricity supplied by the transmission investment continuing to meet their demand. Customers with static demand do not receive the same benefit from the investment, because the reduction in nodal prices is likely to be largely offset by the reduction in LCE that they would have received if the investment was not undertaken.[387] Since the calculation of benefits in this example takes into account LCE as well as the benefits from lower prices and greater transmission volumes, the benefit-based charge would be paid relatively more by the party whose load was growing.[388]

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[387] This would not be the case if the cost of the existing investment is recovered through the residual charge, since then the reduction in LCE would be spread across transmission customers.

[388] The effect of this for benefit-based investments is to make the benefit-based charge more like an exacerbators-pay charge and less like a beneficiaries-pay charge, as described in the DME framework. The DME framework makes clear that exacerbators-pay charges are preferable to beneficiaries-pay charges.

F.19 Some submitters on the LCE working paper were concerned that the potential Code amendment would result in undesirable volatility. However, we consider that allocating LCE to participants who pay for specific assets is unlikely to increase the volatility of charges those customers face. As is the case under the current TPM, customers would receive a credit note against transmission charges.

F.20 Several submissions on the LCE working paper raised concerns about distortions to behaviour if LCE was allocated to specific assets.[389] However, those submissions were originally made in the context of a TPM guidelines proposal which meant that small changes to the behaviour of transmission customers could have led to material changes in transmission charges.

F.21 Under the current proposal, we consider that this is not an issue since the LCE allocated to a user would be based on the transmission charges it pays, which under the guidelines proposal is largely unaffected by its use of the grid at a particular point in time. So a user must pay the nodal transport charge to transport another unit of energy across the grid but its share of the LCE is unaffected by its use of the grid.

F.22 The LCE working paper[390] raised the possibility of extending the averaging period over which LCE was allocated (eg, annually rather than monthly) to limit any distortions to nodal prices and therefore behaviour, caused in relation to allocation of LCE.[391] We are not considering extending the averaging period. The Authority considers that the concern expressed in the LCE working paper would likely be irrelevant under the current proposal because the allocation of the charge for each investment would be fixed when the investment is made (save where the proposed guidelines allow allocations to be changed).

F.23 However, even if it were not, we do not consider the issue to be material. Under the current TPM, South Island generators that pay HVDC charges receive LCE attributed to the HVDC link. If this potential approach to the allocation of LCE gave rise to a risk of distortions to nodal prices sufficient to extend the averaging period, this would also be the case under the current TPM in relation to the HVDC, but there is no evidence of such a problem.

Q61. Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?

Code change 2: Clarifying changes to the ACOT regime

Description

F.24 Amend Part 6 of the Code to clarify that distributors:

(a) are required to make ACOT payments to owners of distributed generation in respect of transitional peak and kvar charges (if these are included in the TPM)

389 For example, the following submissions on the LCE working paper: ASEC (p.6), Genesis (p.4), Powerco (p.2), Transpower (p.1)

390 Transmission pricing methodology: Use of LCE to offset transmission charges: Working paper 21 January 2014, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c7493.

391 Paragraph 7.16, p.22, and paragraph 8.25, p.27.

(b) are not required to make ACOT payments to owners of distributed generation in respect of benefit-based charges, residual charges and/or connection charges.

Discussion

Background

F.25 Part 6 of the Code requires distributors to make avoided cost of transmission (ACOT) payments to owners of distributed generation that cause a reduction in transmission costs,[392] provided that:

(a) the distributed generation was installed before 6 December 2016

(b) the distributed generation appears on a list published by the Authority under clause 2C(1) of Schedule 6.4 of the Code (based on Transpower analysis aimed at identifying distributed generation required to meet the Grid Reliability Standards).

F.26 The Commerce Commission's rules allow price-controlled distributors to recover from their customers (through regulated distribution charges) payments that are made in accordance with Part 6 of the Code (that is, ACOT payments).[393]

F.27 The proposed TPM guidelines would change the basis for ACOT payments. Currently, ACOT payments are based on reductions in distributors' RCPD charges due to the operation of distributed generation. However, if our current proposal for the TPM guidelines comes into effect, distributors would no longer pay RCPD charges. Instead, they would pay other charges, including:

(a) charges with largely fixed allocations such as the benefit-based charge, residual charge and connection charge

(b) variable charges (if these are included in the TPM) such as a transitional peak charge (Additional Component D) and kvar charge (Additional Component G).

F.28 The Authority indicated in its 2016 decision on the distributed generation pricing principles that further refinement of the ACOT arrangements was to be expected. Given the close links between transmission pricing and ACOT, we anticipate that there may soon be a need to clarify the ACOT arrangements under a new TPM.

ACOT for variable charges may encourage efficient operation of distributed generation

F.29 In our view it may be consistent with the Authority's statutory objective for ACOT payments to be made for avoiding either or both of the transitional peak and kvar charges (if these are included in the TPM).

F.30 There is a key distinction in the proposal between two types of charges:

(a) variable charges (the transitional peak charge and the kvar charge), which are intended to influence customers' use of the grid (as they relate to transmission costs that vary based on customers' use of the grid)

(b) charges with a largely fixed allocation (the benefit-based charge, residual charge and connection charge), which are not intended to influence customers' use of the grid.

392 In this context distributors have interpreted transmission costs as transmission charges.

393 Some payments to owners of distributed generation are made by distributors under private contracts that do not directly refer to the Part 6 requirements. These payments may also be recovered by price-controlled distributors through regulated distribution charges.

While the precise amount of these charges may vary over time, customers' allocations should largely remain fixed, subject to provisions of the proposed guidelines addressing exceptional circumstances.

F.31 If the variable charges are included in the TPM it may be efficient for the price signals they send to be passed on to distributed generation, if that would encourage efficient operation by distributed generation that could reduce variable costs. ACOT payments based on reductions in distributors' transitional peak and kvar charges might allow this.

F.32 We are also considering whether to make further changes to Part 6 of the Code so that all distributed generation would be treated alike. The attached drafting of the Code allows for this. If we were to make such changes then:

(a) there would be no distinction between distributed generation based on the date of installation

(b) the lists of ACOT-eligible distributed generation published by the Authority under clause 2C(1) of Schedule 6.4 would not be needed, and would have no further effect.

F.33 The argument for making these further changes would be that ACOT payments in respect of variable charges should be payable to all distributed generation, regardless of the date of installation and of whether or not they appear on the lists of covered distributed generation published by the Authority under clause 2C(1) of Schedule 6.4 of the Code. The reason would be that any distributed generation that is able to reduce distributors' transitional peak charge and kvar charge would – by definition – reduce variable transmission costs, because these variable charges would be designed to accurately reflect variable costs, unlike the existing RCPD charge.

ACOT for fixed charges is not efficient

F.34 The Authority considers that it would not be consistent with our statutory objective for ACOT payments to be made for avoiding transmission charges with a largely fixed allocation (fixed charges). In particular, we consider that ACOT payments based on reductions in fixed charges would not encourage efficient operation by distributed generation, would not provide incentives for distributed generation to operate at particular times and would not reduce variable transmission costs. This is the case for all distributed generation, regardless of the date of installation and of whether or not they appear on the lists published under clause 2C(1) of Schedule 6.4.

F.35 Because customers' allocations of the fixed charges will generally remain constant (save in exceptional circumstances set out in the proposed guidelines), it appears unlikely that distributors would be liable under the existing Code for ACOT payments in respect of these charges as the distributed generation's connection would not enable the distributor to avoid transmission costs. However, the wording of the existing Code may lead to some uncertainty on this point. On the basis of this uncertainty, owners of distributed generation may seek ACOT payments based on reductions in distributors' benefit-based charges and potentially residual charges.[394] So we are considering an amendment to Schedule 6.4 to make it clear that ACOT would not be payable in these circumstances.[395]

394 This possibility was raised by Transpower in its submission on the supplementary consultation paper (page 37).

395 Transpower raised this option in its submission on the supplementary consultation paper (page 38) , in which it said: "One thing the Authority could do, if a benefit-based charge is adopted, is to amend Schedule 6.4 to define ACOT as avoided LRMC charges only i.e. no ACOT for avoidance of benefit-based or residual charges."

F.36 In our view ACOT payments in respect of the benefit-based charge and the residual charge are not required in order to encourage efficient future investment in distributed generation. In most cases the wholesale market will provide sufficient incentives for investment in distributed generation that efficiently reduces transmission network costs. Further, Transpower is able to contract with potential investors in distributed generation whose operation could efficiently reduce or defer transmission network costs. The Commerce Act 1986 provides incentives for Transpower to provide transmission services at lowest cost, which may be via non-transmission solutions.

F.37 Further, retaining ACOT payments with respect to fixed charges could lead to inefficient avoidance behaviour if transmission customers expect charges to be re-calculated. For example, consider a distributor that expects charges for a pre-2019 grid investment to be recalculated due to a substantial and sustained change in grid use. There is a potential risk that it might contract with an investor to build new distributed generation mainly for the purpose of arguing that its benefit-based charges for that pre-2019 grid investment should be reduced (in circumstances where the distributed generation would not otherwise have been built). This would not lead to savings in transmission costs (as the avoided charges relate to a pre-2019 investment) but the distributed generator might attempt to argue that, under the current drafting of the Code, it should nevertheless be entitled to ACOT payments.

F.38 We note that in designing its benefit-based charge, Transpower should take into account any potential inefficiency from this source. If it considers the potential inefficiency is likely to be material it could address this by adopting a gross load approach to measuring demand in certain circumstances.[396] Under a gross load approach, the transmission customer's charges would not be reduced by building distributed generation.

Problem addressed by the amendment

F.39 If transitional peak charges or kvar charges are included in the TPM, it would be efficient for distributed generators to be rewarded for avoiding these charges. However, under the proposed guidelines, it is intended that other charges will be designed so that they are not avoidable. The default provisions in the Code for payments to distributed generators for ACOT would therefore not apply in respect of these charges:

(a) the purpose of the residual charge is to recover residual revenue with minimal distortion to transmission customers' decisions about grid use or investment. The residual charge is designed to be a fixed charge, so that it affects the use of and investment in the grid as little as possible.

(b) once Transpower has determined the share of the benefit-based charge allocated to a transmission customer for an investment, that share would not change except in exceptional circumstances. The benefit-based charge is fixed in this way so that it does not distort use of the grid.

F.40 The allocation of residual and benefit-based charges may need to be revised over time, albeit infrequently. In the case of the residual charge this is likely to involve a recalculation of the volumes used to allocate customers' charges (such as lagged AMD).

F.41 The prospect of revisions to charges could give rise to an expectation of ACOT payments related to possible reductions in transmission charges from reduced grid demand volumes, even though any changes in charges would not reflect a change in economic costs of

[396] See discussion at paragraphs B.114 to B.119.

transmission or, equivalently, benefits from efficient reductions in grid demand. This risks costs from inefficient operation of existing generation and also disputes about the eligibility of distributed generation for ACOT. The Authority's proposed amendment would seek to resolve such issues by making clear when ACOT payments are available.

Q62. Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be efficient?

Code change 3: TPM workability amendment

Description

F.42 Amend clause 12.86 of the Code to add that the Authority may review an approved transmission pricing methodology if it considers that the transmission pricing methodology, or some part of it, has:

(a) become unworkable in its implementation; or

(b) been implemented in a manner inconsistent with the Authority's policy objective contained in the guidelines.

Discussion

F.43 This amendment would prevent the unlikely situation arising where some unforeseen issue prevents the guidelines being implemented in the manner intended. For example, it may be that after the TPM has been approved, in the course of implementing the TPM, Transpower identifies that some aspect is unworkable. Of course, given the process that precedes implementation, the prospect of this is remote but, given the complexities of the subject matter, it is still a possibility. If an issue did arise and if we were dealing with an ordinary piece of Code, the Authority could propose an amendment to address the problem. However, this would not be possible in the case of the TPM, because of the Code requirement (Clause 12.86) that the Authority may only review an approved TPM if there has been a material change in circumstances.

F.44 The Authority considers that this amendment would reduce uncertainty, since it reduces the chances that the TPM cannot be implemented or is implemented in a way that is inconsistent with the intent we have expressed in the guidelines proposal.

Q63. Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?

Q64. In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?

Annex: Potential Code amendment drafting

Schedule 6.4, clause 2 amended and clauses 2A to 2C revoked

2 The pricing principles are as follows:

Charges to be based on recovery of reasonable costs incurred by distributor to connect the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs

(a) subject to paragraph (i), connection charges in respect of **distributed generation** must not exceed the **incremental costs** of providing connection services to the **distributed generation**. To avoid doubt, **incremental cost** is net of—

(i) ~~if the **distributed generation** is included in a list **published** by the **Authority** under clause 2C(1),~~ transmission costs that ~~an efficient **distributor** would be able to avoid~~ would be able to be avoided as a result of the **electrical connection** of the **distributed generation** (being a peak charge or kvar charge but not including any area-of-benefit charge or residual charge imposed by the **transmission pricing methodology**)~~at the **nameplate capacity** specified for that **distributed generation** in the list~~; and

(ii) **distribution** costs that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**:

(b) costs that cannot be calculated (eg, avoidable costs) must be estimated with reference to reasonable estimates of how the **distributor's** capital investment decisions and operating costs would differ, in the future, with and without the generation:

(c) estimated costs may be adjusted ex post. Ex-post adjustment involves calculating, at the end of a period, what the actual costs incurred by the **distributor** as a result of the **distributed generation** being **electrically connected** to the **distribution network** were, and deducting the costs that would have been incurred had the generation not been **electrically connected**. In this case, if the costs differ from the costs charged to the **distributed generator**, the **distributor** must advise the **distributed generator** and recover or refund those costs after they are incurred (unless the **distributor** and the **distributed generator** agree otherwise):

Capital and operating expenses

(d) if costs include distinct capital expenditure, such as costs for a significant **asset** replacement or upgrade, the connection charge attributable to the **distributed generator's** actions or proposals is payable by the **distributed generator** before the **distributor** has committed to incurring those costs. When making reasonable endeavours to facilitate connection, the **distributor** is not obliged to incur those costs until that payment has been received:

(e) if **incremental costs** are negative, the **distributed generator** is deemed to be providing network support services to the **distributor**, and may invoice the **distributor** for this service and, in that case, the **distributed generator** must comply with all relevant obligations (for example, obligations under Part 6 of this Code and in respect of tax):

(f) if costs relate to ongoing or periodic operating expenses, such as costs for routine **maintenance**, the connection charge attributable to the **distributed generator's** actions or proposals may take the form of a periodic charge:

(g) *[Revoked]*

(h) after the connection of the **distributed generation**, the **distributor** may review the connection charges payable by a **distributed generator** not more than once in any 12-month period. Following a review, the **distributor** must advise the **distributed generator** in writing of any change in the connection charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect:

Share of generation-driven costs

(i) if multiple **distributed generators** are sharing an investment, the portion of costs payable by any 1 **distributed generator**—

 (i) must be calculated so that the charges paid or payable by each **distributed generator** take into account the relative expected peak of each **distributed generator's** injected generation; and

 (ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**:

(j) in order to facilitate the calculation of equitable connection charges under paragraph (i), the **distributor** must make and retain adequate records of investments for a period of 60 months, provide the rationale for the investment in terms of facilitating **distributed generation**, and indicate the extent to which the associated costs have been or are to be recovered through generation connection charges:

Repayment of previously funded investment

(k) if a **distributed generator** has paid connection charges that include (in part) the cost of an investment that is subsequently shared by other **distributed generators**, the **distributor** must refund to the **distributed generator** all connection charges paid to the **distributor** under paragraph (i) by other **distributed generators** in respect of that investment:

(l) if there are multiple prior **distributed generators**, a refund to each **distributed generator** referred to in paragraph (k) must be provided in accordance with the expected peak of that **distributed generator's** injected generation over a period of time agreed between the **distributed generator** and the **distributor**. The refund—

 (i) must take into account the relative expected peak of each **distributed generator's** injected generation; and

 (ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**:

(m) no refund of previous payments from the **distributed generator** referred to in paragraph (k) is required after a period of 36 months from the initial connection of that **distributed generator**:

Non-firm connection service

(n) to avoid doubt, nothing in Part 6 of this Code creates any **distribution network capacity** or property rights in any part of the **distribution network** unless these are specifically contracted for. **Distributors** must **maintain** connection and **lines** services to **distributed generators** in accordance with their **connection and operation standards**.

~~**2A Transpower to provide reports to Authority in relation to distributed generation**~~

~~(1) **Transpower** must, by 15 March 2017 (or such later date as the **Authority** may allow), provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Lower South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(2) **Transpower** must, by 30 August 2017, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Lower North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(3) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Upper North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(4) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Upper South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(5) In this clause and clause 4,—~~

~~(a) Upper North Island is that part of the North Island situated on, or north and west of, a line—~~

~~(i) commencing at 38°02'S and 174°42'E; then~~

~~(ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then~~

~~(iii) proceeding north along the 175°27'E line of longitude; and~~

~~(b) Lower North Island is that part of the North Island not referred to in subclause (a); and~~

~~(c) Upper South Island is that part of the South Island situated on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E; and~~

~~(d) Lower South Island is that part of the South Island not referred to in subclause (c).~~

~~**2B Authority to review Transpower's reports in relation to distributed generation**~~

~~(1) The **Authority** must, as soon as practicable after receiving a report from **Transpower** under clause 2A,—~~

~~(a) approve the report; or~~

~~(b) decline to approve the report.~~

~~(2) If the **Authority** declines to approve the report,—~~

~~(a) the **Authority** must, as soon as practicable,—~~

~~(i) advise Transpower of its reasons for declining to approve the report; and~~

~~(ii) direct Transpower as to how it should amend the report before resubmitting it; and~~

~~(b) **Transpower** must amend the report in accordance with the **Authority's** direction, and resubmit the report to the **Authority**,~~

~~(i) for the report provided under clause 2A(1), within 10 **business days**; and~~

~~(ii) for reports provided under clauses 2A(2), (3), or (4), within 20 **business days**.~~

~~(3) The **Authority** must, as soon as practicable after receiving a resubmitted report from **Transpower**,~~

~~(a) approve the report; or~~

~~(b) decline to approve the report.~~

~~(4) Subclause (2) applies to the resubmitted report as if it were the report originally provided under clause 2A.~~

~~**2C Authority to publish list of distributed generation**~~

~~(1) The **Authority** must, after approving a report provided by **Transpower** under clause 2A, **publish** a list of **distributed generation** for the relevant region for the purposes of clause 2(a)(i).~~

~~(2) A list **published** under subclause (1) must include~~

~~(a) only **distributed generation** that is connected as at 6 December 2016; and~~

~~(b) the **nameplate capacity** of the **distributed generation** as at 6 December 2016.~~

Clause 12.86 amended

12.86 Review by the Authority

The Authority may review an approved **transmission pricing methodology** if it considers that:

(a) there has been a material change in circumstances; or

(b) the **transmission pricing methodology**, or some part of it, has:

(i) become unworkable in its implementation; or

(ii) been implemented in a manner inconsistent with the **Authority's** policy objective contained in the guidelines published under clause 12.83.

New clause 14.35A inserted

14.35A Allocation of loss and constraint excess

(1) A **grid owner** must allocate any **loss and constraint excess** (including **residual loss and constraint excess**) it receives in a year:

(a) amongst investments in proportion to the **loss and constraint excess** generated by each investment (including investments whose cost is recovered through the residual charge); and

(b) in respect of each investment (other than those whose cost is recovered through the residual charge), amongst customers in proportion to the transmission charges they pay in that year in respect of that investment

(c) in respect of investments whose cost is recovered by the residual charge, amongst customers in proportion to the residual charge they pay in that year.

(2) This allocation is deemed to be the prevailing methodology for distribution of **loss and constraint excess** payments for the purposes of the **benchmark agreement**.

Appendix G Response to some criticisms

G.1 We have responded throughout this paper to various submissions we have received on previous TPM publications. This appendix provides further context by noting and responding to some criticisms a number of submitters have made of the Authority's approach to review of the TPM, in particular with respect to:

(a) the review process

(b) the basis of the Authority's position and the regard the Authority has had for commentary by submitters and external consultants.

G.2 This appendix is in part prompted by a meeting Authority staff held with members of the 'TPM Group'[397] who met with Authority staff in February 2019. The group members presented their concerns relating to past TPM review processes and sought further engagement with the Authority going forward.

G.3 In February 2017 Counties Power, Counties Power Consumer Trust, Entrust, EMA, Federated Farmers of New Zealand Auckland and Northland Provinces, Trustpower and Vector submitted a report prepared by Dr John Small of Covec, titled *Expert review of expert reviews of transmission pricing methodology reform proposals* (the Covec report).[398] The Covec report was commissioned by the TPM Group, because this "group of stakeholders was concerned the Authority had not fully engaged with the expert advice it had received in its review of the Transmission Pricing Methodology (TPM), and its process to develop replacement TPM Guidelines."[399]

G.4 Members of the TPM Group asked (when they met with Authority staff in February 2019) if the Authority could provide its views on the matters raised in the Covec report. We agreed it would be useful to do so, and agreed to make this summary of our views available with the 2019 issues paper. We think this is useful for all submitters because, 10 years since a review of the current TPM was first initiated, it is useful to reflect on the process we have been through to date. It is also useful to present and explain some of the arguments and counter-arguments that we have considered over time with respect to some of the main policies that we continue to propose.

The Covec report

G.5 The Covec report is a collation of and commentary on views from approximately 60 consultant reports produced as submissions or for submitters to Authority consultations for the transmission pricing review from 2012 to 2016. During this time the Authority presented two major proposals or issues papers (in 2012 and 2016) and a series of working papers over about a dozen consultations.

G.6 The Covec report does not address the earlier work conducted as part of the transmission pricing review. In particular, it does not address the work of the Transmission Pricing Advisory Group (TPAG), which published a discussion paper in 2011, or the Electricity Commission, which published a consultation paper on high-level options in 2009 and a

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397 At the time of publication of the Covec report, the TPM Group members were Counties Power, Counties Power Consumer Trust, the Employers and Manufacturers Association (EMA) Northern, Entrust, Federated Farmers Auckland, Northpower, Top Energy, Trustpower, and Vector.

398 Small, J, *Expert review of expert reviews of transmission pricing methodology reform proposals*, Covec, February 2017. Published under *Submissions* at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c16277https://www.ea.govt.nz/dmsdocument/21882

399 *Ibid,* page 3.

Stage 2 options consultation paper in 2010. The Authority's analysis and proposals used this earlier work as an input into our work, along with work by the Transmission Pricing Technical Group and the New Zealand Electricity Industry Steering Group.

A concern that the Authority has not considered expert views

G.7 A key theme, and a genesis of the Covec report, is the concern that the Authority has not engaged with expert advice presented in consultant reports. For example, it states:

> "For the most part, the EA's style throughout this process has been to avoid citing particular critics. Instead it has tended to refer to 'submissions' in the aggregate, without identifying particular arguments made by individual experts, claim they have been considered and then reiterate the EA's view. This style is unfortunate in the current context, where there is a substantial weight of expert opinion that opposes the EA's desires: it suggests that the EA is not actually engaging with the submissions."[400]

G.8 We acknowledge that we have not always cited either proponents or critics of the proposal in our TPM consultation papers. However, the Authority must and does consider all views submitted to it, expert or not, provided by consultants or provided directly by submitters. Not citing specific submitters or their consultants does not equate to ignoring their views in formulating our thinking on transmission pricing.

G.9 In fact, the thinking that has underpinned the TPM review proposals has been heavily informed by the insights from expert economists and consultants, as well as other submissions. For example:

(a) the concepts of benefit-based charging and the approach to calculating benefits follow the approach suggested by Professor Hogan in 2011[401]

(b) the concept of an area-of-benefit charge originated from Castalia in its report for Genesis Energy on the beneficiaries pay working paper[402]

(c) our scepticism about the value of a long-run marginal cost (LRMC) or some other peak charge, given New Zealand has 'gold standard' marginal pricing incentives (nodal pricing), was informed by a report from Professor James Bushnell (on behalf of Trustpower) on the options working paper.[403] Our consideration of an LRMC charge followed submissions from the Electricity Networks Association (ENA)[404] and Transpower[405] on the beneficiaries-pay working paper.

G.10 The views of external consultants and other stakeholders have also influenced the Authority's process. For example:

400 *Ibid*, paragraph 301.

401 Hogan (2011).

402 Castalia. *Transmission pricing methodology: beneficiary pays options*, report to Genesis Energy, March 2014.

403 Bushnell, J. *Equity and efficiency implications of New Zealand's Transmission Pricing Methodology options*, August 2015.

404 ENA, submission on TPM beneficiaries-pay working paper, 25 March 2014.

405 Transpower, submission on TPM beneficiaries-pay working paper, 25 March 2014.

(a) the Authority decided to publish and seek submissions on a series of working papers[406] in response to submissions on the first issues paper from October 2012 and at the subsequent TPM conference in May 2013

(b) the Authority's decision to produce and publish the sunk costs working paper[407] was in response to submissions by the Competition Economists Group (CEG) on behalf of Transpower[408] and other submitters who argued that altering charges on sunk costs cannot produce efficiency gains and could result in efficiency losses.

Criticism of the policy development process

G.11 The Covec report criticised the Authority for failing to follow a 'disciplined' policy process in conducting the TPM review.

G.12 It is important to consider the longevity of the review and the extent to which each consultation has built on earlier work when looking at the policy process.

G.13 Review of the TPM has involved a conventional policy process consisting of establishing objectives, identifying problems, developing options, identifying a preferred option and testing this with cost-benefit analysis. The 2016 issues paper followed this approach and so does this 2019 issues paper.

G.14 Some aspects, like objectives, problems with charges, and the nature of options were first articulated by the Authority as far back as early 2012 when we released our consultation paper on the TPM decision-making and economic framework.[409]

G.15 Where issues were identified with aspects of the review during consultation, such as with the problem definition or cost-benefit analysis, the Authority has sought to respond to those issues. The problem definition has been refined over time partly in response to submitter feedback. For example, in their submissions on the first issues paper, Mighty River Power and Transpower submitted that the Authority's analysis had not established that there were inefficiencies with the interconnection charge.[410] In response, the Authority presented detailed analysis in the problem definition working paper,[411] followed by extensive further analysis of this issue in the options working paper[412] and in the second issues paper[413].

Explanation of long-standing elements of the proposal

G.16 The Covec report stated that the Authority was intent on pursuing three consistent 'goals' throughout the review:

406 The working papers are available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

407 Electricity Authority, Working Paper – Transmission pricing methodology: Sunk costs, October 2013

408 CEG, *Transmission pricing methodology – economic critique*, February 2013.

409 Electricity Authority, Decision-making and economic framework for transmission pricing methodology review, January 2012. Available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c6767

410 Mighty River Power submission on first issues paper, Appendix A, page 3. Transpower submission on first issues paper, Appendix A, page 4.

411 Electricity Authority, *Transmission pricing methodology: Problem definition relating to interconnection and HVDC assets: Working paper,* 16 September 2014. See in particular pages 42-57, 59-62, 65-83, 100-103.

412 Electricity Authority, *Transmission pricing methodology review: TPM options: working paper*, 16 June 2015, pages 16-23.

413 Electricity Authority, *Transmission pricing methodology: issues and proposal, Second issues paper,* 17 May 2016, pages 52-71.

(a) removing the HVDC charge

(b) creating a charge based on the benefits of individual transmission investments

(c) extending this charge to existing grid assets established since 2004.[414]

G.17 Regarding these three 'goals' as identified by the Covec report, we explain below the origin of our position on each:

(a) The proposal to remove the HVDC charge arose in response to problems first identified by the TPAG in 2011, which were accepted by the Authority.[415] Transpower's 2015 operational review addressed some of these problems (namely, the distortion to operational efficiency from the HAMI charge). However, the Authority considers that the problem of distortion to investment in South Island generation remains.

(b) The proposal to introduce a beneficiaries-pay charge based on benefits of individual transmission investments reflects the views of international experts, such as Professor William Hogan, that charging on the basis of benefits is an effective approach to promoting efficiency.[416]

(c) We first proposed to apply the benefit-based charge (which at the time we called the 'area-of-benefit' charge) only to new investments in the options working paper ('Application B') in 2015. After considering submissions on that paper, we then proposed (in the second issues paper) to apply the charge to existing post-2004 investments valued at more than $50 million, along with Pole 2 of the HVDC, as well as new investments (ie, 'Application A' in the options working paper). In our supplementary consultation paper we proposed adding an additional component, which would allow the charge to be applied across *all* historical investments.

During our preparation for this 2019 issues paper, we sought the opinion of Professor Hogan on the issue of applying benefit-based charges to historical assets. Professor Hogan said there was nothing that he was aware of to suggest that there was anything inefficient or inappropriate in applying beneficiaries-pay charging to existing assets, provided no incentives for inefficient entry or exit are created. He also noted that such incentives can be avoided by using the tools we have considered (such as provision for reassignment in the case of under-utilised assets).[417]

We emphasise that, while the proposal in the 2019 issues paper also includes benefit-based charges on post-2004 investments and Pole 2, our views on this matter (and indeed our views on any matter that is the subject of this proposal) are not fixed.

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414 Small, J, *supra* note 2, paragraph 295.

415 TPAG, *Transmission pricing discussion paper*, 7 June 2011.

416 See also Perez-Arriaga et al (2013), Lévêque (2003), chapter 7.

Some external consultants who submitted on the Authority's second issues paper have also agreed in principle with beneficiaries-pay charging, such as Compass Lexecon, even if they did not agree to applying such charges to historical assets. In particular, in paragraph 6 Compass Lexecon states: "The use of a beneficiaries-pay principle for new investments ... may promote dynamic efficiency by making beneficiaries accountable for the expansion of the grid as long as the approach is based on defining charges proportional to net benefits and granting beneficiaries the ability to block investments." Schoeters, MA, Spiller, PT, for Compass Lexecon, *Transmission pricing mechanism in New Zealand: An analysis of the Electricity Authority's proposed options*, prepared on behalf of Vector, 11 August 2015. Appendix to Vector submission on TPM second issues paper.

417 See Filenote: *Teleconference with Professor William (Bill) Hogan of Harvard University*, 17 May 2018

G.18 Accordingly, these are all elements of our proposal but are not goals in and of themselves. The Covec report stated that a substantial weight of expert opinion is against the adoption of these elements. We outline below some of the – in our view – more persuasive arguments against these elements of our proposal and our responses to them.

Arguments relating to removing the HVDC charge

G.19 Professor Yarrow, quoted on page 69 of the Covec report, said the Authority should not be responsive to lobbying:

> "…Application B (or an alternative approach that reflects outcomes in relevant, workably competitive markets in a similar way) has the following, two attractive features: Its adoption would signal that the EA has been relatively unresponsive to past lobbying…. Its adoption would signal that the potential gains from lobbying (aimed at securing redistributive benefits in future policy exercises) could be expected to be lower than has previously been the case."[418]

G.20 We think the argument about responsiveness to lobbying cuts both ways: in relation to both those lobbying for and against the status quo. We do not consider that lobbying is always a negative, as we do want parties to tell us about problems. However, we agree that we should not take any action or decision simply in order to placate any party. Ultimately, any future decision on whether to retain or remove a particular charge, such as the HVDC charge, or introduce new charges must be based on which path best promotes the Authority's objective.

G.21 The key question with respect to the HVDC charge is whether retaining or removing it would deliver net benefits. We consider that removing the HVDC charge would achieve efficiencies by reducing the disincentive to generation investment in the South Island currently caused by the HVDC charge.[419]

Arguments relating to introducing a benefit-based charge

G.22 The three main criticisms we have heard about charging according to benefit are that:

(a) it would introduce new distortions to use of the transmission network and investment

(b) it is not practical

(c) it is complex.

Distorting use and investment?

G.23 Bushnell and Wolak (2017) state:

> "Allocating the costs of networks according to the concept of beneficiaries pay can be an attractive principle until one recognizes that any assignment of fixed network costs distorts behavior – either in the short term (through changes in operating behavior), or long term (through changes in investment incentives), or both. While we consider this approach more reflective of social or regulatory policy than of markets,

418 Yarrow, G, *Some awkward problems raised by the Electricity Authority's Review of the Transmission Pricing Methodology*, February 2017, Appendix D to Trustpower submission on Second issues paper: supplementary consultation, page 14.

419 We did consider addressing this problem by restricting the HVDC charge to existing South Island generation only but rejected this option because it would undermine competition.

there are nonetheless appealing equity aspects to the notion that one can assign costs to those who gain the most.

However, if the entity that benefits most from an upgrade, and therefore pays the highest per kWh cost to use the grid, is also the one most able to take actions [to] reduce the amount it pays for the grid, then a 'beneficiaries pay' principle can lead to very inefficient energy and ancillary services market outcomes. The risk is that charging parties too much, or in an inefficient way, can undermine the very benefits upon which the case for the upgrade were predicated. One does not want to discourage use of expensive infrastructure simply as a consequence of attempting to recover sunk costs."[420]

G.24 Bushnell and Wolak acknowledge that the Authority is attempting to avoid distorting use by making benefit-based charges largely fixed and independent of use.[421] Accordingly, their primary concern about distortions from application of the benefit-based charge relate to distortions to investment.

G.25 All TPMs will distort both use and investment to some degree. We acknowledge too that charging according to benefit will result in locational differences in transmission charges, which may affect investment decisions. We treat this as a cost in our CBA. In our CBA in chapter 4, we estimate the magnitude of the potential distortion from load and generation not locating in regions with recent investments in capacity. According to our CBA, there *is* likely to be such a distortion, but the costs associated with that distortion are likely to be outweighed by the increases in efficiency resulting from the introduction of the benefit-based charge.[422]

G.26 We think those locational differences in transmission charges will, over time, better reflect the underlying costs of providing transmission services to different regions. We think those differences could promote more efficient investment over the long term, eg, by requiring an investor in wind generation to take into account the relative transmission costs of investing at a location close to or distant from load.

G.27 We also note that those, such as Bushnell and Wolak, who reject benefit-based charging advocate continuing to apply connection charges.[423] As we explained in chapter 5 of the second issues paper, our economic rationale for charging beneficiaries of an investment is analogous to that for requiring customers of connection assets to pay connection charges. At a high level, the key difference between the connection charge and benefit-based charges is how the beneficiaries are identified: connection uses a physical definition while the benefit-based charges use a calculation of benefit. As far as the charges themselves are concerned, they are very similar: both charge for an investment to supply identified beneficiaries and the rate of the charge recovers the cost of the investment from those who benefit from it over its life.

G.28 Accordingly, our proposal could be considered as an extension to the boundary for determining connection assets and therefore connection charges. While we acknowledge the concerns around the benefit-based charge distorting grid use and investment, these same concerns should also apply to the connection charge. Since these concerns do not

[420] Bushnell, J and Wolak, FA, *Beneficiaries-pay pricing and "market-like" transmission outcomes,* February 2017, page 8, Appendix F to Trustpower submission on TPM supplementary consultation paper

[421] *Ibid.,* footnote 7.

[422] See chapter 4.

[423] Bushnell, J, and Wolak, FA, *supra* note 24.

outweigh the benefits in the case of the connection charge, we think the same should also be the case with the benefit-based charge.

G.29 Submitters, such as Bushnell and Wolak, have pointed to the HVDC charge as an example of why a benefit-based charge is problematic because of the divergence between forecast and actual benefits over time.[424] Hogan (2011) addresses this uncertainty point head on. As he says, "Treatment of uncertainty is not simple, but it is unavoidable…. The scenario analysis is an approximation, but this is not fatal for either the investment evaluation or the [benefit based] cost allocation."[425] He also makes the point that the benefits must be determined as part of the decision about whether or not to invest, irrespective of how the investment is actually paid for. He suggests that, "In many instances, estimating the *shares* of benefits is easier than estimating the benefits."[426] *[emphasis added]*

G.30 In addition, Bushnell and Wolak's citation of the HVDC charge as an example of the problems with beneficiaries-pay charges does not take into account the relationship between the HVDC investments and HVDC charges. In particular, when the HVDC charge was first introduced and applied to South Island generators it recovered the costs of Pole 1 and Pole 2, from which South Island generators were clear beneficiaries. Since then, Pole 1 has been decommissioned, Pole 3 has been commissioned, and it provides additional services including round power that were not provided by Poles 1 and 2.

G.31 As a result, the beneficiaries and the share of benefits may have changed but the parties subject to the HVDC charge have not changed. Our proposal avoids the problem of replacement investment providing different services over time to different beneficiaries by charging according to forecast benefits from the replacement investment. In particular, there would be separate benefit-based charges for investments that change the life or the benefits of the original investment. This means that, if the beneficiaries and flow of benefits from a replacement or upgrade investment change, this is reflected in the benefit-based charge for that investment.

G.32 Submitters identifying concerns about distortion to use and investment from the benefit-based charge have suggested that investments in the interconnected grid should be recovered through a charge based on Ramsey pricing (where customers are charged at a rate inversely proportional to their sensitivity to changes in price).[427] This is on the basis that such a charge least distorts behaviour in economic terms (assuming that the charge does not have any value in signalling the cost of users' decisions). Although, with this assumption, a Ramsey charge is in some sense optimal, we are not aware of any situation where Ramsey pricing is applied in practice in its pure form.

G.33 Our proposal does, in fact, incorporate elements of Ramsey pricing, in the form of an expanded prudent discount policy, which would provide a discount to a customer's charges (including the benefit-based charge) where they could demonstrate the charges would distort their investment decisions.

G.34 We agree that spreading the charges across grid users in some way that approximates Ramsey pricing would avoid the distortions that Bushnell and Wolak identify. But it does have a cost. The cost is that users would not face, and so would not take in to account, the

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424 *Ibid*.

425 Hogan, WW, *supra* note 5.

426 *Ibid*.

427 E.g. Creative Energy Consulting, *A response to Meridian's submission to the TPM consultation,* September 2016, Appendix C to Trustpower submission on TPM supplementary consultation paper.

costs in terms of transmission investment that their own decisions generate.[428] We have discussed the impact of this in incentivising inefficient investment both in this paper and in the second issues paper. Our assessment is that the inefficiency identified by Bushnell and Wolak is likely to be outweighed by the increases in efficiency resulting from the introduction of the benefit-based charge.[429]

G.35 This is the heart of the ‘marginal cost controversy’ debate between Coase and the marginalists.[430] Consistent with our position, Frischmann *et al* (2015) concluded in a review article on this debate that: “The arguments marshalled by Coase (and his contemporaries) not only succeeded in this particular debate, as we shall see, but more generally served as part of the foundation for various fields of modern economics”.

G.36 We note that Creative Energy Consulting criticised NERA’s citation of the Coase article as backing two-part tariffs and benefit-based charges on the basis that Coase only advocated such charges where costs were attributable to individual customers but not when there are common costs.[431]

G.37 We agree that Coase’s formal analysis assumed costs were clearly attributable to individuals, but consider that Coase himself thought the principle more broadly applicable. For example, in the same article, he refers to establishing prices for use of a bridge,[432] and elsewhere he comments “[My] rejection of marginal cost pricing reflects the view that it is a mistake to concentrate simply on the marginal conditions when examining a proposal. It is the total effect (in which what happens at the margin is only one factor) which matters.”[433]

G.38 In any case, our proposal does attribute the cost of transmission investments to particular customers, namely those who benefit from it. For example, we do not consider investments such as NIGU are ‘common costs’, as the technology, location and scale and therefore cost are clearly attributable to particular customers.

Practical?

G.39 With respect to the practicality of the benefit-based charge, the Authority considers that it has demonstrated that it is practical to calculate charges based on benefits on multiple occasions, including in the current proposal. We do, however, appreciate the issues raised by Scientia Consulting about the sensitivities of benefit calculations to assumptions and the impact of investment dependencies on benefit calculations.[434]

G.40 However, our assessment is that the sensitivities that Scientia examined were not marginal. Further, as noted by Hogan (2011), uncertainty is a fact of life and needs to be addressed in the investment decision.[435] Accordingly, we have consistently considered that calculation of benefit-based charges needs to take into account this uncertainty. This could occur, for example, through the use of scenarios.

428 They will only do that if they face a benefit-based charge.

429 See also Appendix B.

430 Coase, RH (1946), pages 169-182.

431 Creative Energy Consulting, *supra* note 31, page 10.

432 Coase, RH, *supra* note 34.

433 Coase, RH (1970).

434 Scientia Consulting, *Technical evaluation of AoB approach used in the TPM second issues paper*, July 2016, Appendix E to Transpower submission on TPM second issues paper.

435 Hogan, WW, *supra* note 5.

G.41 Further, under the Commerce Commission's capital expenditure (capex) input methodology, in 'major capex proposals' and applications to the Commission for approval of 'listed projects', Transpower is required, to the extent reasonably possible, to provide a quantitative estimate of the benefits from the investment expected to be delivered to Transpower's customers.[436] This should mean that for those large grid investments Transpower can draw on the analysis required for this task to assist it with the calculation of benefit-based charges.

G.42 Further, the fact that charges based on benefits have been applied in the United States, Chile and Argentina demonstrates that it is practical to apply benefit-based charges.[437] Each of the three ISOs or RTOs we met in the United States operates a beneficiaries-pay approach which is used to allocate the costs of at least some grid investments. While the scope of coverage for benefit-based charges and the methods used in these jurisdictions differ from the approach proposed in New Zealand, the benefit-based principle is the same.[438] We therefore consider that the practical challenges of a benefit-based approach are not insurmountable.

Complex?

G.43 In most cases we propose a customer's share of charges would be calculated just once under a benefit-based charge. Exceptions would be rare. In contrast under the current TPM a customer's share of the interconnection or HVDC charges is recalculated annually – which, as evidenced by recent changes to Electricity Ashburton's transmission charges for 2019-20, can cause substantial price volatility year on year.

G.44 We think submitters' concerns about complexity relate mainly to the method we have used to calculate benefits. We have used the vSPD model, a model virtually identical to that used to operate the wholesale market, and which wholesale market participants should be familiar with. We have used the vSPD model to calculate proposed charges for seven recent major investments in this proposal.

G.45 The approach used by the three ISOs or RTOs we met in the United States involves modelling the forecast benefits of investments using system planning software models, which are of a similar (or greater) order of complexity to the vSPD model.

G.46 Furthermore, in response to this concern, we propose that Transpower may use a simpler method for smaller investments in designing the TPM, and may use proxies even under the standard method. This is likely to make the charges less accurate in reflecting benefits. Nevertheless, we consider that these charges will be relatively efficient despite this potential inaccuracy.

436 Commerce Commission, *Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination),* consolidated version as at 1 June 2018, clause 7.5.1(1)(b).

437 Both Argentina and Chile calculate capacity charges using an area-of-influence method. Schoeters, MA, Spiller, PT, *supra* note 20, pages 42-43,

438 Costs have been allocated on a beneficiaries-pay basis for around 50 projects by PJM and five projects by MISO. NYISO has yet to commit a project, but has two 'public policy' investments in process with recovery expected to be 75% by beneficiaries-pay and 25% socialised. See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018. Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/release-of-joint-report-beneficiaries-pay-in-usa/

Applying benefit-based charges to seven major investments

G.47 The aspect of our proposal that has been most subject to debate is applying benefit-based charges to some recent major investments. We emphasise that our proposal *does not* involve retrospective charges – that is, changes to historical charges that customers have already paid. Our proposal *only* involves changing future charges. The main arguments submitters have advanced against applying benefit-based charges to some historical investments are that such charges would:

(d) distort behaviour while being unable to alter the efficiency of those investments

(e) introduce unfairness and so undermine, rather than promote, durability.

G.48 With respect to distortions to behaviour, the general tenor of submitters' concerns is reflected by the following comment from Bushnell (2015):

> "…it would be inappropriate to use such supplemental charges [such as the AoB charge] to recover the costs of investments that have already been made. This could only distort current behavior, and have no impact on the grid investment itself as those investments, and their costs, are sunk. Therefore, the goal of economic efficiency is best served by the 'Application B' option, which would place less capital costs from existing investments under the new pricing regime."[439]

G.49 As discussed above, we have attempted to design the proposed benefit-based and residual charges to minimise distortions to use, as distinct from investment, from application of these charges. In addition, we are proposing a transition that would limit the size of the impact of application of the benefit-based charge to some historical investments, and therefore further limit distortions to behaviour.

G.50 Minimising distortion is not the same as spreading the charges uniformly across all customers. As is noted above, we have sought to follow the approach first advocated by Coase (1946) of imposing charges for investments attributable to particular customers (ie investments that benefit particular customers) on those customers,[440] ie beneficiaries.

G.51 We acknowledge concerns that the proposal to apply benefit-based charges to recent investments could impact investment going forward, as, for example, Axiom (2016) describe:

> "There can be no dynamic efficiency benefits gained from signalling to generators that it is cheaper for them to locate in areas where assets are 'older'. Regardless of whether assets are old or new, their costs are sunk. This distinction can therefore only give rise to dynamic inefficiency." [441]

G.52 While we recognise this risk (and have quantified the dynamic inefficiency that Axiom refers to in our CBA), we consider that in some respects our proposal reduces such dynamic inefficiency. In particular, we think replacing the HVDC charge with benefit-based charges on all beneficiaries of HVDC Pole 2 and 3 will to some extent address the long-standing problem that the current HVDC charge provides an excessive disincentive to generation investment in the South Island. This includes regions with a lack of generation and generation competition, notably the upper South Island.

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439 *Supra* note 7, page 2.

440 See Coase (1946) op. cit.

441 Axiom Economics, Economic Review of Second Transmission Pricing Methodology Issues Paper, A report for Transpower, July 2016, page 29.

G.53 More generally, we think judgements about dynamic efficiency need to consider both positive and negative effects. Accordingly, while applying a benefit-based charge may provide disincentives for generation to invest in areas where existing investments are subject to the charge, the benefit-based charge will also mean that generators need to consider the future transmission investment implications of locating in other areas as well. We also agree with Professor Littlechild that not applying the benefit-based charge to historical investments would mean foregoing the benefits of providing information about the value of future investments.[442] We think the overall effect will be to promote more efficient investment rather than detract from it.

G.54 Moreover, the Commerce Commission regime for major capital proposals and listed projects is now designed to approve only investments that reflect efficient costs of a prudent supplier.[443]

G.55 To the extent that previously-approved investments were efficient, the beneficiaries of the investment would have been prepared to pay for them because the benefits to them would have exceeded the cost. That means the benefit-based charge would not cause them to exit.[444] The same cannot be said if we instead choose to recover the cost of the investments through Ramsey-like charges. That will recover the cost of the investment from some parties who get little or no benefit from it. If the charge were poorly reflective of Ramsey principles, which we think is the case with the interconnection charge calculated on the basis of RCPD, the magnitude of the charge might be sufficient to cause them to exit when they would have been viable but for the charge.

G.56 We have also argued that applying the benefit-based charge to existing investments will promote durability. If this does result in a more durable TPM, this should reduce uncertainty, which should be beneficial for investment and therefore promote dynamic efficiency. Some submitters, however, consider applying charges to historical investments will increase disputes and uncertainty rather than reduce them. For example, Creative Energy Consulting criticise the durability of this approach as follows:

> "But, by including some historical assets, but not others, within the AOB regime, by drawing a 'line in the sand', the EA has just created some new grounds for claims of unfairness: for example, from customers in Northland, who appear to be paying for the majority of the cost of the assets that serve their region, through the new AOB charge and, in addition, a share of the older assets serving all other regions, through the residual charge." [445]

G.57 In our view, the question of whether a TPM is more or less durable is a matter of judgement. Our assessment is the prospect of new investment in some areas affects the

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442 Littlechild, S, *Report on the Electricity Authority's Transmission Pricing Methodology Review,* 26 July 2016, page 14.

443 The Commission's capital expenditure input methodology was reviewed and amended in 2018. See Commerce Commission, *Transpower capex input methodology review: Decisions and reasons* (29 March 2018).

444 Coase (1970), *supra* note 38, points out the absurdity of not charging for these investments:

"Apparently, what the advocates of marginal cost pricing had in mind was that the Government should estimate for each consumer whether he would be prepared to pay a sum of money which would cover the total cost. However, if it is decided that the consumer would have been willing to pay a sum of money equal to the total cost, then – and this strikes me as a very paradoxical feature of this argument – he will not be asked to do so. ..I found this a very odd feature. …The way we discover whether people are willing to pay something is to ask them to pay it."

445 Creative Energy Consulting, *Review of the Electricity Authority's TPM second issues paper,* July 2016, page 23, appendix to Trustpower submission on second issues paper.

durability of any TPM. In particular, we think durability would be undermined if beneficiaries of these new investments have to pay for these as well as help pay for large recent investments in other areas they don't benefit from. Meanwhile, the actual beneficiaries of those large recent investments would only have to pay part of the costs of the investments they benefit from, further undermining durability.

G.58 We think there are several factors that reduce the impact of our current proposal with respect to applying benefit-based charges to historical investments. First, under the Commerce Commission's input methodology that establishes a total revenue cap for Transpower, Transpower is able to recover more of the costs of an investment early in its life.[446] In the case of the seven large historical investments we propose be subject to benefit-based charges, since most of them were commissioned in the early part of this decade, a significant portion of the costs will actually already have been paid by customers that are not the primary beneficiaries.

G.59 Second, we are no longer proposing to apply benefit-based charges to three of the historical investments that we proposed applying the area-of-benefit charge to in the second issues paper. For two of these, Otahuhu GIS and NAaN, any benefits would be likely to flow mainly to upper North Island customers but, since the estimated benefits do not exceed the costs, we propose to recover the costs of these investments through the residual, so these costs would also be spread between the primary beneficiaries and other customers.

G.60 Finally, as we note above, we have included:

(a) a transition mechanism to manage the impact of moving to recover the costs of these investments from beneficiaries

(b) an additional component to allow Transpower to apply the benefit-based charge to all historical investments, which would mean that all customers would pay for the investments they benefit from. This component can be implemented if, in Transpower's reasonable opinion, it would better meet the Authority's statutory objective.

Is there evidence of a problem of inefficient transmission investment?

G.61 A theme of the Covec report is that the Authority has failed to present evidence that the existing TPM does not promote efficient investment.

G.62 In our view, it is reasonable to presume – and is a standard assumption in economics – that parties, in deciding what is best for them, will take into account charges they pay as a consequence. If transmission charges are substantially less than the costs to New Zealand imposed by those parties' decisions, it can be presumed that on occasions decisions will be made that are in the parties' self-interest but which impose net costs on New Zealand.[447]

446 Under the Commission's Asset Valuation input methodology that applies to Transpower for the purposes of information disclosure and the setting of the revenue cap, the regulatory asset base (RAB) is not subject to indexation, which results in the investment being recovered earlier than if it had been indexed. This contrasts with the input methodologies for electricity distributors, where the RAB is indexed.

447 Coase (1970), *supra* note 38, makes this point with respect to decreasing marginal cost industries like transmission: "Note that marginal pricing [ie, in our context, pricing using LMP without a benefit-based charge] makes it impossible for consumers to choose rationally between two alternative uses of factors that are required for production but do not enter the marginal cost" page 118.

G.63 There are examples of likely inefficient grid investments. When analysing the benefits of the post-2004 large historical grid investments (those with costs exceeding $50 million), to identify benefit-based charges, we were not able to identify net benefits for three of the investments: North Auckland and Northland (cost $473 million), Otahuhu GIS (cost $106 million) and Upper South Island dynamic reactive (cost $55.2 million). These investments were all approved by the Electricity Commission.[448] While we note the benefit calculations we have conducted for these investments were historical and only considered benefits early in the lives of these investments, the lack of net benefits at this point raises questions around the efficiency of the timing of construction at the very least.

G.64 That several such major investments — with a total cost of more than $500 million — may have costs exceeding benefits confirms there are legitimate questions about whether the transmission pricing regime is fit-for-purpose, and effective in supporting the transmission investment approval regime. This is for two main reasons.

G.65 First, under the Commerce Commission regime, if the Commission approves a transmission investment, then Transpower is able to recover the costs of that investment under the TPM, subject to the application of incentive mechanisms in the Commission's capital expenditure input methodology.[449] As a result, apart from amounts that are shared between Transpower and its customers under the incentive mechanisms, the risk of the investment failing is transferred from Transpower to its customers.

G.66 Charges that spread the costs widely reduce incentives on customers to scrutinise investments, even if they are inefficient or inefficiently risky, or to present useful information on more efficient alternatives. The Commerce Commission's major capex and listed projects grid investment approval processes provide a robust method to test the costs and benefits of those larger investment proposals. However, this process would be enhanced if customers had incentives to reveal information that more accurately reflected a proposal's net benefits or considered the merits of alternatives.

G.67 Second, the cost-benefit analysis reported in this issues paper provides evidence that the existing TPM likely does not promote efficient investment. For example, our modelling of investment behaviour by load customers demonstrates that the existing RCPD charge could be expected to cause inefficient investment in batteries that would be made mainly to avoid the RCPD charge.

G.68 The Covec report emphasises the opinion of Professor Yarrow that when a firm, such as Transpower, is subject to economic regulation the firm has incentives to design efficient prices, and a greater ability to do so than the regulator, as it has better information about its customers. However, this view does not take into account two important factors.

G.69 First, if Transpower does not charge only those who benefit from an investment the cost of the investment, transmission users (who may or may not be Transpower's customers but may include consumers to whom charges are passed through) will have an incentive to

448 Investment approval documentation for these investments is available at: NAaN: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/; Otahuhu GIS: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/otahuhu-substation-diversity-proposal-history/; USI reactive support: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/grid-development-proposals-archive/ige-applications/upper-south-island-reactive-support-history/

449 Commerce Commission, *Transpower capex input methodology review: Decisions and reasons* (29 March 2018), page 33, Figure 5: Overview of new capex incentive regime.

undertake inefficient investment, because they will treat the cost of additional transmission investment caused by those decisions as minor to the point it is not relevant to their own investment decisions.

G.70 This can be demonstrated by considering the location decisions of gas-fired generators who could potentially face both electricity and gas transmission costs. Under the status quo, except for the costs of connecting to the grid, North Island gas-fired generators only need to consider gas transmission costs (but are not charged electricity transmission interconnection costs). As a consequence, gas-fired generators tend to locate close to their source of gas. However, if they also had to face the transmission costs, they may decide to locate closer to the customers they are supplying with their generation.

G.71 Second, like any firm, Transpower's incentives are to maximise its profits.[450] Under its regulatory regime it can do this by increasing its revenue, because the more revenue it receives the greater its profits will be. Building more assets can increase revenue. In our view, the current TPM facilitates this because a load customer that benefits from an interconnection investment does not have to pay the full cost of the investment.

G.72 This is reinforced by the fact that, under the current TPM, aside from the HVDC, generators pay nothing towards interconnection investments, regardless of the extent to which their location decisions impact on interconnection asset costs.

G.73 The Covec report implies that the Authority does not trust the Commerce Commission's ability to screen investments, and that the Authority does not provide any supporting evidence of inefficient investments actually having been approved.[451]

G.74 The review of transmission pricing is not a question of trust in or effectiveness of the Commission's process. It is about achieving efficient transmission pricing signals. We are concerned about the consequences of an inefficient *pricing* regime (which the Authority is responsible for). Inefficient transmission pricing affects:

(d) investment by generation or consumers, which may be inefficient if their decisions do not reflect the cost of transmission

(e) transmission investment via:

(i) investment and use decisions by users of the transmission grid, which will affect the timing, location, nature and scale of transmission investment

(ii) the extent to which transmission customers have incentives to support or oppose transmission investments.

G.75 We have already discussed how investment and use decisions by users would affect demand for transmission investment. With respect to the second proposition, the quality of a regulator's decision is clearly influenced by the information they have available to them.[452] On that point, we consider that the current RCPD charge is structured in a way that:

(a) encourages transmission customers to support a grid investment option that they would individually benefit from, even if it is not the best solution, and

450 In fact, pursuit of profitability is a statutory objective. Transpower is a state-owned enterprise and, accordingly, its financial objective is to "operate as a successful business" and "be as profitable and efficient as comparable businesses that are not owned by the Crown", State-Owned Enterprises Act 1986, section 4(1)(a).

451 Small, J, *supra* note 2, paragraph 13-19.

452 This result has also been well established in economics since the publication of the seminal article by Jensen and Meckling (1976).

(b) provides little incentive for transmission customers to provide Transpower and the Commission quality information that would assist in the scrutiny of a grid investment proposal.

G.76 By contrast, we would expect our proposal to provide strong incentives for stakeholders to provide information to ensure the investment decision was of high quality. This would mean that the Commission's process would be better supported by transmission pricing.

Distinction between the guidelines and the TPM

G.77 The Covec report queried the 'very detailed' nature of TPM guidelines proposed by the Authority and questioned what the Authority's rationale was for presenting a high level of detail. It stated: "As Professor Yarrow has noted, regulators of natural monopolies … frequently take the view that the regulated firm knows best how to design its charges. This is because the regulated firm (i.e. Transpower) interacts directly with its customers on a regular basis and therefore has superior information to regulators about the most efficient ways to earn revenue."[453]

G.78 The implication is the guidelines should be less prescriptive and perhaps Transpower is in a better place to determine the detail in the TPM.

G.79 We have considered this point carefully and consider that the appropriate level of prescription varies, considering:

(a) who has the best information and incentives to design, develop and/or implement a workable TPM based on the guidelines?

(b) what are areas that must be reflected in the final methodology to ensure the Authority's policy intent is most likely to be achieved, and where is flexibility needed to enable adaptation?

G.80 The proposed guidelines in this issues paper reflect these considerations by varying the level of prescription from relatively prescriptive (as in schedule 1) to relatively high level, as in the principles set for Transpower in clause 1. The proposed 2019 guidelines reflect detailed feedback from Transpower staff on an earlier draft of the guidelines in order to improve their clarity and workability.

Submissions have led to substantial changes to the TPM proposal

G.81 The Covec report suggests that the Authority has been rigid in its views about transmission pricing, and that certain aspects of our proposal remain unchanged despite opposing expert views.

G.82 It is true that we have continued to propose to move to a beneficiaries-pay approach instead of the existing HVDC and interconnection charges, for the reasons discussed above.

G.83 It is also true, however, that we have changed our position about many aspects of our proposals to a substantial degree over time. In doing so we have been influenced by the views of external consultants, among others. Such changes include:

(a) changing from calculating benefits from an ex post to an ex ante (forecast) basis[454]

453 Small, J, *supra* note 2, paragraph 24.

454 Castalia, *supra* note 6, Trustpower submission on beneficiaries-pay working paper, section 6.2. We note, in particular, the following from Trustpower's submission on the approach to applying beneficiaries-pay charges,

(b) removing the cap on benefits for calculating charges[455]

(c) changing the method of calculating the residual charge from a variable to a fixed basis[456]

(d) changing from applying the residual charge to generation and load to just load[457]

(e) proposing and then withdrawing the deeper connection charge[458],[459]

(f) proposing[460] and then withdrawing a LRMC charge[461]

(g) introducing the ability to include a transitional peak charge[462]

(h) introducing the ability to apply the benefit-based charge across the entire grid rather than limiting it to large post-2004 assets[463]

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which is reflected in the design of the benefit-based charge: "If the Authority intends to persist with a beneficiaries-pay charging methodology, Trustpower considers it should select a pricing approach which is based on long-term forecasts of benefits and beneficiaries. If necessary, this could provide for charges to be recalculated periodically as and when there are changes to the use of the grid…. [W]e would expect charges to be based on offsetting benefits calculated over the lifetime of a transmission asset, over a range of potential scenarios. Only parties with offsetting benefits would be charged." Paragraphs 6.2.1, 6.2.3, page 12.

455 Bushnell, J, *Efficiency and cost recovery for transmission network investments*, March 2014. Appendix to Trustpower submission on beneficiaries pay working paper; Meridian submission on beneficiaries pay working paper; Orion submission on beneficiaries pay working paper.

456 Transpower submission on the TPM first issues paper; ENA submission on the TPM first issues paper. These parties submitted that the Authority needed to be clear about whether the residual should incorporate a pricing signal or should be non-distortionary. For example, the Orion submission on the first issues paper stated: "If the objective is indeed minimizing distortion in use of the grid, as opposed to efficient peak avoidance, an allocation based on market share would seem to be more appropriate." (page 21).

457 Unison submission on first issues paper; Redpoint, *Evaluation of New Zealand transmission pricing review against international experience,* 18 February 2013, Appendix to Trustpower submission on TPM first issues paper,

458 The deeper connection charge was developed, at least in part, in response to criticisms that charging options higher on the Authority's DMEF had not been considered, eg see PwC for 21 EDBs, submission on beneficiaries-pay working paper, paragraph 11.

459 While the deeper connection charge was considered in the second issues paper, it was not proposed as the cost-benefit analysis used for that paper (which was subsequently discredited) indicated lower net benefits. As outlined in chapter 9 of the second issues paper, also influencing the decision not to proceed with deeper connection were that:

- customers could face deeper connection charges exceeding private benefits — see CEG for Transpower, submission on options working paper, page 72)
- it was less effective than the area-of-benefit charge at promoting efficient investment — the following submissions, amongst others, identified issues relating to inefficient investment from the deeper connection charge: CEG *ibid*,, Castalia for Genesis submission on options working paper, pages 16, 18, 19, Scientia for Transpower submission on options working paper, pages 19-20, ENA submission on options working paper, page 9, CEG, ibid., page 5, Marlborough Lines submission on options working paper page 8
- the identification of assets and parties subject to the charge was complex and likely to result in distortions to behaviour — see the following submissions on the options working paper: Buller, page 6, Counties Power, page 13, ENA pages 8-9, EPOC, page 12, Genesis, page 6, Castalia for Genesis, pages 16, 19, CEG for Transpower, page 70, Orion, page 6, Pioneer, pages 2, 3, The Lines Company, Tauhara No. 2 Trust, page 3, Scientia for Transpower, page 13,14, 19-20, Trustpower, page 14.

460 ENA, *supra* note 8, Transpower, *supra* note 9.

461 Bushnell, *supra* note 7.

462 The decision to include a transitional peak charge was influenced by Transpower's submission on the supplementary consultation paper that not having an RCPD-based or LRMC charge could affect demand response, which could in turn impact on reliability and system security.

463 NZAS submission on the second issues paper; Transpower submission on the second issues paper.

(i) introducing transition mechanisms[464]

(j) proposing and then withdrawing an extension to the prudent discount policy to address inefficient exit.[465]

G.84 In addition, numerous other changes have been made to our proposal and the draft guidelines in response to comments from submitters.

G.85 The Covec report does not reflect the substantial changes to the Authority's proposal over the course of the review (beyond acknowledging some changes). The Authority considers its approach of tallying supporting or opposing views from external consultant reports submitted throughout the course of the review to be inappropriate in two respects:

(a) Our proposal has changed over time as noted above. The tallying fails to acknowledge this.

(b) More importantly, the Authority considers any issues raised in submissions by external consultants and other submitters alike on their merits, not in terms of numbers for or against. The Covec report in fact reinforced exactly this point. It found that most external consultants criticised the Authority's decision-making and economic framework or its elaboration in the second issues paper. However, the Covec report agreed "… with NERA's view that this chapter is 'not contentious from an economics perspective'."[466]

The Authority is proposing a TPM that it has assessed best meets the statutory objective

G.86 We agree with Covec that there is no perfect TPM. Our proposal reflects trade-offs between different efficiency objectives.

G.87 The Covec report, by its tallying of external consultant views, implies however that there is consensus amongst external consultants. But submissions including from external consultants have expressed a broad range of views on particular TPM approaches. Our review of submissions showed a wide range of views from submitters and their external consultants on whether, for example, the TPM should:

(a) have an LRMC or another peak charge

(b) be based on benefits and, if it is, how this should be calculated

(c) include a residual charge on generation and, if so, to what

(d) apply to specific investments

(e) apply to historical investments and, if it does, which ones

(f) remove the HVDC charge

(g) specify the calculation of the residual charge.

464 Fonterra, submission on beneficiaries-pay working paper, paragraph 12.6.

465 The following submissions submitted that this proposed extension of the prudent discount policy would increase inefficiency: Genesis Energy, Top Energy, Counties Power, Molly Melhuish, Fonterra, Castalia for Genesis, King Country Energy (KCE), Pioneer, Vector, EA Networks, Unison, Orion, HoustonKemp for Trustpower, Mighty River Power, Powerco, Transpower, Trustpower, PwC (for 14 EDBs), Electric Power Optimisation Centre.

466 Small, J, *supra* note 2, page 119.

G.88 Regardless, it is not the number of submissions for or against that determines our approach to an issue but the substance of the position each submission is expressing.

G.89 We have discussed above what has influenced our thinking in proposing the benefit-based charge and applying it to new investments and some historical investments. In addition to the issue of the investments to which the benefit-based charge is applied, other matters on which external consultant views were advanced include:

- whether an accurate assessment of beneficiaries is appropriate
- whether a fixed capacity measure is appropriate for benefit-based and residual charges
- whether the cost allocators are appropriate
- whether it is appropriate to include distributed energy resources in the assessment of capacity.

G.90 Where appropriate, we address external consultant opinions on these matters in the 2019 Issues paper in the discussion about our proposal. For the most part, this relates to external consultant opinions on the second issues or supplementary consultation papers, as the proposal has changed significantly from that in earlier papers, in part because of responses to consultant opinions. However, we make the following general observations with respect to these matters:

G.91 *Accuracy of assessment of benefits:* Some external consultants, as cited by Covec, have questioned the practicality of estimating benefits and whether an accurate assessment is appropriate.

G.92 As noted at paragraph A.42 above, our discussions with the US jurisdictions who have applied beneficiaries-pay charges for several years confirm it is practical to apply a beneficiaries-pay approach to allocate the costs of transmission investments (acknowledging that our proposed approach is not identical to the approach adopted in US jurisdictions but is broadly similar).467

G.93 In relation to accuracy, we agree with the comment from NERA cited in paragraph 282c of the Covec report that precision of calculation of benefits is not necessary to achieve material efficiency gains relative to the status quo.

G.94 *Use of a fixed capacity allocator:* Comments on the second issues paper cited by Covec relate to whether allocation on the basis of fixed capacity will allow charges to reflect benefits over time. Deciding on an allocation method involves a trade-off between avoiding distortions to behaviour from the charge and reflecting the change in a party's circumstances over time. Our proposal attempts to make this trade-off by charging in a relatively rigid way but also providing mechanisms that allow adjustments to reflect certain changes in circumstances.

G.95 *Appropriateness of cost allocators:* The comments cited by Covec relate to whether it is appropriate to remove the RCPD charge. As we comment elsewhere, including in the 2019 issues paper, we think nodal prices should be the primary mechanism for incentivising efficient use of the grid.

G.96 We note the comment by James Bushnell cited by Covec (paragraph 290a) that peak usage may be an appropriate proxy of the allocation of costs and benefits, "particularly if it

467 Electricity Authority, Commerce Commission, Transpower, June 2018, *supra* note 43.

reasonably captures the conditions triggering those costs". As we have commented at length throughout the TPM process, we do not consider the RCPD charge reasonably captures the conditions triggering transmission costs. Further, to the extent it does, it undermines the effectiveness of nodal pricing. However, because of concerns raised by Transpower and other submitters about potential unintended consequences from removal of the RCPD charge, our proposal includes an additional component that provides for introduction of a transitional peak charge.

G.97 We also note comments by some submitters that the current RCPD charge reflects Ramsey pricing principles.[468] We think this relationship is very weak. A charge that follows Ramsey pricing principles should not involve significant distortions to behaviour, but the current charges do the opposite: substantial investment targeting avoidance of the RCPD charge, withdrawal of interruptible load during RCPD periods and avoidance of the RCPD charge in regions with falling or flat demand.

G.98 Our approach is to design a residual charge that seeks to minimise incentives to inefficiently alter use and rely on nodal pricing to provide signals about use that reflect the real-time state of supply and demand on the transmission network.

G.99 *Inclusion of distributed energy resources in calculation of the residual charge:* We propose to calculate a load customer's share of the residual charge based on demand "grossed up" for injection by distributed generation or behind-the-meter generation as we think this better reflects customer size, and therefore ability and willingness to pay for transmission costs. It also provides better assurance that load customers will not be encouraged to invest in distributed generation or batteries just to avoid charges.

Conclusion

G.100 In conclusion, we have considered matters raised in submissions we have received to date, including those identified in the Covec report, and will carefully consider submissions made in respect of this 2019 issues paper.[469] We have altered our proposal in response to various issues validly raised. However there are also some issues or arguments raised in submissions that we do not accept, including those identified by Covec that criticise our policy process, for the reasons outlined above.

G.101 As well as detailed consideration of submissions, we also sought the views of Professor Hogan to identify whether there were any problems with our proposal with respect to the application of the benefit-based charge to recent major investments that would necessitate us changing our approach. However, he identified no such problems.

G.102 Our decision on whether to confirm our proposal will, however, depend on the outcome of our consideration of submissions on the 2019 issues paper. The submissions we receive will be subject to thorough analysis before we make our decision.

G.103 We continue to be open to persuasion by submissions presenting arguments of substance, from all and any parties – whether a stakeholder or an external consultant. While we have chosen in this section to focus on matters raised within the Covec report in particular, these points are merely illustrative of the many views put forward in the course of this review.

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468 For example, Creative Energy Consulting, *supra* note 31, page 20.

469 Please note, as we have said elsewhere in this 2019 issues paper, if you wish the Authority to consider again an argument or some evidence that you have provided in a previous submission, you are welcome to cross refer to the specific place in your previous submission where that point is covered.

G.104 We have arrived at the proposals in the 2019 issues paper after thorough consideration of the views of all stakeholders, not limited to the ones put forward in the Covec report by consultants.

G.105 We currently consider that while no TPM proposal can ever be perfect, on balance our proposal as presented in this 2019 issues paper would promote the Authority's statutory objective including by promoting the creation of a TPM that would be in the best long-term interests of consumers for the foreseeable future. However, we do not claim to have achieved perfection and we look forward to considering submissions as to how our 2019 proposal can be improved.

Q65.	**Do you have any comments on the matters covered in this appendix G?**

Appendix H Method and assumptions: impact modelling and proposed benefit allocation

H.1 This appendix provides a description of the methods and assumptions we have used to produce:

(a) the information on indicative year-one transmission charges in chapter 5

(b) the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A).

H.2 The Authority invites submitters to provide feedback on key assumptions and modelling decisions we have made in determining the allocation of benefit-based charges. In some cases we have considered alternatives before adopting a particular approach. We have included questions around the options considered in this appendix.

H.3 The Authority has published on the Authority's Electricity Market Information (EMI) website a set of files showing the calculations and technical notes on the methods used.

Method to calculate indicative customer charges in chapter 5

H.4 The primary task of chapter 5 is to show (indicatively) the change in the allocation of Transpower's annual costs among its customers in the first year if the proposed guidelines were implemented via a new TPM, compared to the allocation under the current TPM.

2022 is assumed to be the first year of pricing under a new TPM

H.5 The pricing year 2021/2022 (referred to as 2022) is assumed to be the first year of pricing under a new TPM. This assumption is conservative in the sense that it results in relatively large year-one impacts. The first year of pricing may be later than 2022. If this is the case, the depreciated value of the seven major historical investments subject to the benefit-based charge would reduce further and the impact of the change in charges that is due to those investments would be less than shown in chapter 5.

H.6 Transmission charges are set out only for the first year of a new TPM. The purpose is to show the immediate change caused by the shift to a new TPM and the resulting reallocation of the costs of historical investment in the grid. It is more difficult to show expected charges in subsequent years of a new TPM. This is because each year Transpower would allocate new expenditure via the benefit-based charge. The impact of this on customers' charges would depend on which customers Transpower identified as benefiting from that new expenditure.

H.7 Transpower has provided us with estimates of its breakdown of annual revenue for each benefit-based investment for 2022 (based on RCP3 forecasts). Transpower's expected total revenue requirement for 2022 is sourced from the Commerce Commission's draft decision on Transpower's revenue for RCP3.[470]

Transpower's customer list

H.8 A list of Transpower's current customers was sourced from the information on customer charges disclosed by Transpower under the Commerce Commission's Information Disclosure regulation.

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470 Transpower's individual price-quality path from 1 April 2020 – Draft decisions and reasons paper – 29 May 2019. Available at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpowers-price-quality-path/setting-transpowers-price-quality-path-from-2020?target=documents&root=102833 .

H.9 Those customers' points of connection (POCs) have been identified, with some adjustments based on Transpower's advice. In the few instances where multiple customers are connected to the same POC we have allocated benefits (and charges) between customers in proportion to volume (load or injection).

H.10 Charges are estimated for Transpower's customers only as these are the only parties that Transpower can charge directly. We have not estimated the impact of the proposed changes to the TPM on distribution charges.[471] That is a matter for each distributor. For example, Pacific Steel is owned by NZ Steel and is a customer of Vector. Any effects a new TPM based on the proposed guidelines would have on distribution charges incurred by Pacific Steel would be a matter for Vector. So we have not taken this into account in estimating transmission charges for NZ Steel.

We first estimate charges under the current TPM

H.11 To estimate the indicative impact of a new TPM on charges, we first estimated customer charges that would apply under the current TPM for 2022.

H.12 The starting point for this estimate is the customer charges provided in Transpower's disclosure under the Commerce Commission's Information Disclosure regulation for the most recent available year (2019/20).[472] We used this information to set the estimated allocation of the RCPD charge and of the HVDC charge in 2022. That is, we have assumed that the allocation of the RCPD charge and of the HVDC charge would be the same in 2022 as in 2019/20. This is based on an assumption that customer behaviour would be unchanged.

H.13 We needed to take into account the expected reduction in Transpower's revenue requirement for 2022 (as compared with 2019/20). To ensure that the total of estimated charges is equal to Transpower's revenue requirement for 2022, we applied the 2019/20 allocations to the 2022 revenue. We did this separately for interconnection revenue and HVDC revenue. This is because interconnection revenue and HVDC revenue are expected to decline at different rates between 2019/20 and 2022.

H.14 Our estimate of customer charges under the current TPM in 2022 is imperfect, as:

(a) customer usage or generation in 2022 would likely vary from the levels we have assumed to some extent

(b) Transpower's revenue for the benefit-based investments and its revenue relating to other costs recovered through the residual charge could turn out to be different to the estimates it has supplied[473]

(c) it does not account for changes to the allocation method for the HVDC charge (discussed below).

H.15 We have not taken into account changes to the allocation of the HVDC charge resulting from the gradual transition from a Historical Anytime Maximum Injection (HAMI) basis to a

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471 Similarly, we have not estimated the impact of the proposed changes to the TPM on the further allocation of transmission charges by other transmission customers (such as directly-connected industrials) to other businesses connected to their networks.

472 Transpower Information Disclosure Schedules F1-6, G1-8, SO1, Disclosure Year, 30/06/2018, sheet F6 titled 'Revenues', 'Current Year +2' (Forecast year), being the pricing year to 31 March 2020.

473 Transpower's revenue for regulatory control period 3 (RCP3) (for 2020/21 to 2024/25) will not be finalised until November 2019 according to the Commerce Commission website. Refer: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpowers-price-quality-path/setting-transpowers-price-quality-path-from-2020.

South Island Mean Injection (SIMI) basis.[474] This migration would be complete by 2022. We did not adjust for this as it is unlikely to result in a material distortion to charges. Note that the change to the allocation of the HVDC charge only affects South Island generators.

We then calculate indicative charges under the proposal

H.16 We have estimated indicative customer charges that could apply under a TPM based on the proposed guidelines for 2022. To do this, we have calculated allocations of the charges that would apply under such a TPM (including the benefit-based charge and the residual charge) and applied those allocations to Transpower's expected revenue requirement for 2022.[475]

H.17 **The allocation of the connection charge is the same as in 2019/20.** We split out the connection charge and apply it to customers in the same proportions as were disclosed for the most recent available year, with a reduction in the charge to account for the expected change in Transpower's expected revenue requirement for RCP3. Under the Authority's proposal the guidelines with respect to the connection charge would not change materially. We therefore assume the way Transpower would calculate the connection charge would not change (so we did not model changes to the connection charge).

H.18 **We have calculated the benefit-based charge for seven major investments.** Transpower provided a breakdown of the estimated depreciated value of the seven major investments listed in clause 13(b) and schedule 1 of the proposed guidelines, and operating and maintenance costs attributable to those investments for years up to 2024/25. These were used to determine the modelled amount to be recovered in 2022 for each of the seven major investments in schedule 1 (as set out in Table 14below).

Table 14: Indicative amount recovered for each of the seven major investments

Investment	Modelled amount recovered ($m in 2022)
NIGU	60.5
HVDC (Poles 2 and 3 combined)	98.9
LSI Renewables	2.7
Wairakei Ring	9.1
BPE-HAY reconductoring	6.5
UNI dynamic reactive support	4.9
LSI Reliability	2.4

H.19 The modelled amount to be recovered in 2022 for each of the seven major investments was then allocated according to the percentage of benefit for that investment proposed for each customer in schedule 1 of the proposed guidelines. The method we used to determine the percentages in schedule 1 is discussed below under the heading "Method to calculate the allocation of benefit to schedule 1 investments".

474 Following Transpower's operational review 1 (which took place over 2014 – 2015) a decision was made to change the allocation of the HVDC charge from HAMI (a peak charge) to SIMI (a volume-based charge). In the 2019/20 pricing year HVDC charges are allocated 25% according to HAMI and 75% according to SIMI. Refer: https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/operational-review-1.

475 To calculate $/MWh charges for 2022, we needed to estimate 2022 volumes. To do this, we took recent consumption figures (over the 2014 – 2018 period) and increased consumption / injection for each customer (load / generation) by 1% per annum.

H.20 **We calculate the residual charge.** The residual charge recovers any of Transpower's regulated revenue that is not recovered by either the connection charge or the benefit-based charge.[476]

H.21 For the calculation of indicative residual charges, we have assumed that the residual charge is allocated based on gross anytime maximum demand (AMD),[477] for each POC/Network for each of the four years from 1 July 2014 to 30 June 2018. We calculated the average of the four years for each POC/Network. The 4-year average smooths out outliers in any single year.

H.22 We used data available from the Reconciliation Manager (reconciliation data file 010) to measure half-hourly demand, as we consider this to be the most robust source of half-hourly gross demand available.

H.23 The AMD calculation is on a 'gross' basis. This means any distributed generation connected to the distribution network is not netted off against demand. For example, if for years 1, 2, 3 and 4 respectively, a POC/Network had maximum demand of 10, 15, 20 and 25 MW, and distributed generation in those same trading periods of 0, 5, 10, and 15 MW, the gross AMD at that POC/Network would be (10+15+20+25)/4 MW.[478]

H.24 As mentioned earlier, there are some instances where there are multiple customers behind a POC. In these circumstances the split between customers is determined by combining 'POC' and 'Network' in the reconciliation dataset (ie, POC/Network). For example, POC WHI0111 comprises two networks: Contact Energy and Pan Pacific Forest Industries. By creating a separate POC/Network reference for each (WHI0111_CTCT and WHI0111_PANP), the AMDs can be calculated separately for each customer.

H.25 Where a customer has multiple POCs, that customer's gross AMD will be the sum of the gross AMD of each POC. An alternative approach would have been to pool demand for each customer across locations and calculate the AMD of the pooled demand.[479]

H.26 Where a customer has multiple networks, AMDs for each of the customer's networks were then rolled up into a total AMD for a Transpower customer. Adjustments were made based on information provided by Transpower. Where we have needed to make important assumptions and apply judgement in particular cases, we have recorded these and published them on the Authority's EMI website.

We compare charges under current TPM and the proposal and apply the cap

H.27 We compared the indicative charges for each transmission customer under the proposal to the charges estimated for the current TPM. This gives us the 'raw' impact of the policy change on customers. This raw impact is published on the Authority's EMI website.

H.28 We then applied the price cap calculation as provided for in the proposed guidelines.

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476 Transpower also earns a comparatively small amount of income from notionally embedded agreements (NEAs) and prudent discount agreements (PDAs). In the 2019/20 pricing year, this was disclosed as $3.04m.

477 AMD is the trading period with the highest demand (in MW) measured at each POC and network over a pricing year. There are instances where there is more than one network (and customer) at a POC

478 By contrast, net AMD would be (10+10+10+10)/4. Note however that once the distributed generation is subtracted from the maximum load for each trading period, the net AMD periods might change, for example, to periods when distributed generation was not running.

479 Refer appendix B.

Method for allocation of benefit to seven major investments

H.29 This section describes the modelling approach we used to generate the percentages in schedule 1 of the proposed guidelines. The percentages are the portion of benefit (and charges) proposed to be allocated to each customer for each of the seven major investments listed at clause 13(b) of the proposed guidelines. Below we set out the data inputs, key decisions and assumptions made that materially impact the allocation, the alternative options we considered, and the modelling steps.

Beneficiaries were identified using vSPD

H.30 The vectorised Scheduling, Pricing and Dispatch tool (vSPD) is used to identify the beneficiaries of each of the transmission investments in schedule 1. The vSPD model emulates real market half-hourly price and quantity outcomes at approximately 250 nodes across New Zealand's transmission network.

H.31 The approach for identifying the beneficiaries and estimating benefits involves running the vSPD model:

(a) with the investment in question (the factual case)

(b) without the investment in question (the counterfactual case).

H.32 Changes in prices and quantities due to the investment can then be determined at each of the approximately 250 nodes in each half-hour trading period by comparing vSPD results in the factual case with those in the counterfactual case.

H.33 Running the vSPD model requires making input assumptions. In many cases we have applied judgement in selecting an appropriate assumption – particularly in respect of describing the counterfactual case (that is, what would have happened over the long term had the investment in question not been built).

H.34 If removal of the investment (running the vSPD model in the counterfactual case) results in a constraint on the system, this creates price separation between nodes on each side of the constraint. That is, the nodal price downstream of the constraint increases to ration the use of the system to its capacity. In that case, the investment provides load downstream of the constraint with lower electricity prices and better reliability due to the removal of a constraint. Investments in transmission also reduce electricity losses and this provides loss benefits. Loss benefits are typically distributed fairly evenly across the grid.

H.35 The following steps illustrate the approach taken using vSPD for each half hour (refer Figure 20 below for a simplified illustration of the benefit calculation).

(a) Step 1: Solve the final pricing schedule with transmission asset(s) in place (solve 1).

(b) Step 2: Calculate the benefit (producer surplus) to injection and off-take participants (consumer surplus) at each node using the scheduled quantities and prices from solve 1.

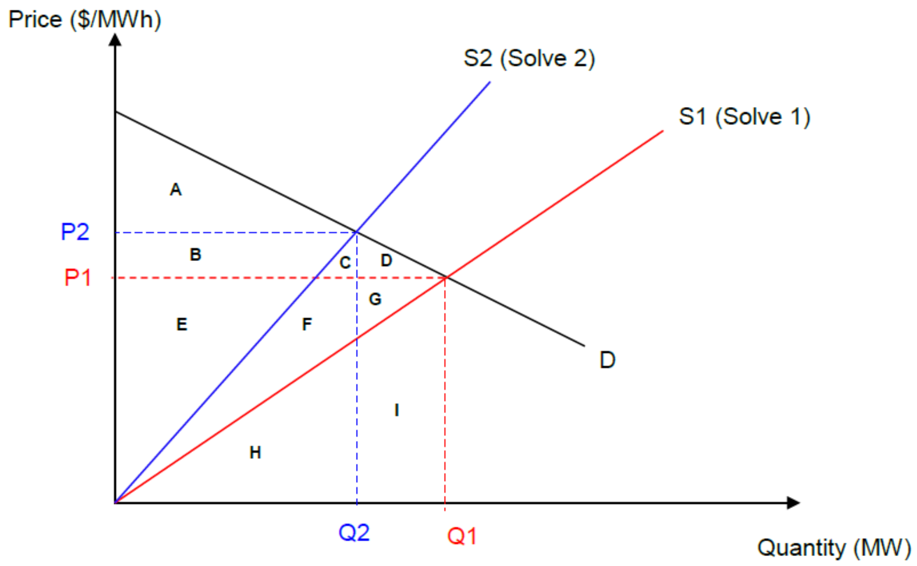
(c) Step 3: Remove the transmission asset(s) and re-solve the final pricing schedule (solve 2). Refer to the section on VPO below for a discussion of this process.

(d) Step 4: Re-calculate the benefit to injection and off-take participants at each node using the scheduled quantities and prices from solve 2.

(e) Step 5: Calculate the change in benefit for each participant at each node due to the removal of the transmission asset(s) (from solve 1 to solve 2). Refer to Figure 20.

(f) Step 6: Those participants with a positive change in benefit at a node from Step 5 are classified as beneficiaries with the calculated change indicating the extent of the benefit.

Figure 20: The calculation of benefits using vSPD



	Solve 1	Solve 2	Change
Demand (offtake)	A + B + C + D	A	B + C + D
Supply (injection)	E + F + G	B + E	F + G - B

We use data from a 'typical' historical year to model benefit

H.36 We have assumed that the distribution of benefits over a recent historical period (2014 – 2018) is a reasonable proxy for the likely distribution of forward-looking benefits of the investments under consideration. This means we have made no adjustments to reflect either demand growth or new grid-connected generation.

H.37 This approach differs from the modelling that supported the 2016 proposal, for which we developed a future scenario (taking a base year and then increasing demand and generation investment to account for growth over time). The Authority considered submissions on that proposal that made the point that the modelling was overly complex. In response, for the 2019 proposal we have simplified the approach by using historical data.

H.38 Our approach is pragmatic. For a future grid investment, it is feasible to forecast a factual and counterfactual scenario. However, this task is much more difficult for a historical investment. In the latter case, the design of a robust counterfactual would involve unravelling all subsequent investments in generation and on the demand side that had been made since the grid investment was built, and then creating a replacement investment sequence that would have occurred under the alternative (counterfactual). This would be a complex undertaking and given the level of assumptions required, it could lead to spurious accuracy.

H.39 The estimate is robust to changes or unusual circumstances that occur in any single year, as we have used multiple separate years of data and averaged the results, to provide a reasonable range of scenarios indicative of a 'typical year'.

H.40 The Authority considered two options for defining the recent historical period:

(a) a two-year modelling period ending 30 June 2018

(b) a four-year modelling period ending 30 June 2018 (currently the Authority's preferred option).

H.41 The Authority chose to estimate benefits using market data over four years and averaged the results from the four separate years (from 2014/15–2017/18). (The Authority also decided to use the same four-year timeframe as the basis for allocating an indicative residual charge.) The Authority considers that this four-year modelling period averages out variances from annual and seasonal patterns, without being too outdated. The advantage of using the two-year period would be that it would mean relying on the most recent data only. However, the four-year data profile more closely matches the decade-long hydrological profile. This means it is more likely to produce results that are representative of long-term benefits. This option would best promote the long-term benefit of consumers, as in the Authority's view – for the reasons set out above – the resulting allocation between customers is more likely to approximate the distribution of the benefits of the investment (compared to a two-year modelling period).

Q66. Over what period should we undertake the vSPD modelling?

Determining the counterfactual scenarios

H.42 Determining the appropriate counterfactual is an important decision, because it affects both the estimated benefit of undertaking the investment (and so whether it is assessed to be efficient) and the distribution of benefits (and so who pays benefit-based charges in respect of the investment).

Fixed or variable virtual price offer (VPO)

H.43 Our vSPD modelling method requires making assumptions about the wholesale electricity prices that would have occurred in the scenario in which the relevant grid investment was not made (the counterfactual scenario). We call these assumptions the virtual price offer (VPO). The Authority considered two options:

(a) a fixed VPO (fixed at $500/MWh)

(b) a variable VPO as described below (currently the Authority's preferred option).

H.44 A VPO fixed at $500/MWh is based on the assumption that a diesel peaker would have been built to support reliability when there is not enough transmission and local generation to meet demand. The Authority does not consider this assumption to be realistic where demand growth is substantial over time, as it is not plausible that demand growth would have been served over a sustained period by expensive peaking generation.

H.45 Developing a counterfactual for an existing investment such as the North Island Grid Upgrade (NIGU) necessitates taking a view on what would have happened if that investment had not been commissioned. For example, perhaps:

(a) diesel peakers would have operated to cover shortages in Auckland

(b) several Auckland-based generators that closed in the factual scenario would not have closed in the counterfactual, and instead would have continued to offer in at their short run marginal cost (SRMC)

(c) Taranaki-based peakers that (in the factual) use the North Island Grid Upgrade to deliver their electricity to Auckland might not have been commissioned or might have been built at different locations.

H.46 The Authority's view that without NIGU a longer term solution would have been found at a cost much less than $500/MWh.

H.47 Our preferred option (variable VPO) is to assume that wholesale prices would have been a maximum of 20% higher in the counterfactual scenario compared to the factual scenario in which the grid investment was built. This assumption is based on experience that sustained prices much higher than 20% over the average are typically not observed. The variable VPO assumption also takes into consideration the absence of demand response in the vSPD model runs, and expectations around increasing levels of demand response over the life of the investments (discussed below). Some customers may reduce their demand in response to high prices, and in particular, very high prices. Further, the variable VPO assumption addresses a simplification of vSPD whereby generator offer tranches, which are an input into vSPD, are fixed. In practice, generators would likely change their offers in response to changing market conditions, or where a transmission line becomes unavailable.[480]

H.48 Lastly, available indications of the future cost of alternatives to transmission (including batteries and distributed generation) also suggest a price in this range is appropriate.

H.49 In the Authority's view, a variable VPO would best promote the long-term benefit of consumers, as – for the reasons set out above – the resulting allocation between customers is more likely to approximate the distribution of the benefits of the investment (compared to a fixed VPO).

H.50 We modelled the benefit-based charge under both the variable and fixed VPO options to enable interested parties to analyse customer impacts of the Authority's preferred option and the alternative option. The results of this modelling are available on request. The Authority currently considers that a variable VPO is the most appropriate approach for the initial benefit-based charge. We look forward to receiving submissions on this matter.

Further discussion of the VPO

H.51 As an investment becomes more fully utilised there would be increasing levels of unserved energy on the downstream side of an investment in the counterfactual case (without the investment), which we price at the level of the VPO. As the quantity of energy subject to the VPO increases, this provides scope for investment in less expensive forms of generation in the counterfactual case. For example, if there are only a few trading periods where VPO is assigned, either this would be left as unserved energy and priced at the value of lost load (VoLL), or a diesel peaker would be brought in at around $500/MWh. As an asset becomes more fully utilised and there are a high number of trading periods where VPO is applied in the counterfactual, this provides the case for a gas-fired peaker to enter, or even less costly forms of base-load generation, priced at around $70/MWh.

H.52 An important point to note is that, the higher the VPO price is in $/MWh, the greater the total benefits from an investment as calculated in vSPD and the higher the benefit to load

480 Variable VPO does not affect high prices in the counterfactual case unless removal of the investment being assessed leads to unserved energy in the counterfactual. Sometimes vSPD generates high prices in the counterfactual because, where there is a capacity shortage, higher generator offers (from a generator's offer tranche) might be dispatched in the model. We dealt with prices we considered infeasible by removing them in post processing.

(versus benefit to generation). If an existing investment has barely been utilised, the appropriate VPO price may be on the high side. In this case a greater share of the benefits of the investment would accrue to load customers. As the asset becomes more fully utilised, the appropriate VPO price drops, and a greater share of the benefits would accrue to generation. Logically, an investment that is only required during the highest peaks provides benefits related to reliability – and load customers tend to benefit more from reliability than do generation customers.

H.53 For a post-2019 investment, the development of an appropriate VPO assumption will be more important. However, it is also likely to be less problematic. The Authority considers that developing a VPO assumption for a new investment would require less judgement than that for an existing investment. This is because under the Commerce Commission's regulation, Transpower is required to consider alternatives to transmission investment. A future cashflow comparison of the grid solution and a non-transmission alternative could be used to inform a VPO assumption for future grid investments.

Q67. Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either case, what is the appropriate level of the VPO?

Demand response

H.54 We have not adjusted prices in the counterfactual to take account of potential demand response to the higher prices resulting from the absence of the grid investment.[481] The Authority's view is that this approach results in reasonable estimates of benefit, as we have made various adjustments to address the prospect of unreasonably high prices, including:

(a) the VPO assumption (both variable and fixed) essentially caps higher prices where there is unserved energy in the counterfactual, providing an effect not dissimilar to demand response

(b) in circumstances where VPO does not apply, we dealt with prices we considered infeasible by removing them in post processing

(c) we reduced the effect of outliers in the modelling through separately calculating benefits over four years and then averaging those benefits. For example, in a dry year South Island load benefits substantially from the HVDC (prices in the counterfactual are high), but this only occurred in one year of the four years in the modelling period.

Gross vSPD versus net vSPD versus traditional vSPD

H.55 The Authority's proposal is that the application of the benefit-based charge to the seven major investments be carried out on a net load basis. By this, we mean that we recognise distributed generation (or other generation that is permitted to be netted) behind a point of connection, so that its injection would 'net' off against total demand. For example, if a network's demand is 100MWh, but 50MWh of this demand is supplied by local generation connected behind the point of connection, then the net demand at that point of connection would be 50MWh, whereas gross demand would be 100MWh.

481 The CBA takes into account demand response. Further, previous vSPD modelling included demand response assumptions for two customers. The vSPD modelling for the 2019 proposal does not, and explicitly avoids bespoke adjustments. Bespoke adjustments will be considered following analysis of information in submissions, as outlined in the section titled, 'Treatment of approved/committed distributed generation, entries and exits, and other adjustments.'

H.56 In the Authority's view a net load basis for calculating benefit-based charges for the seven major investments would best promote the long-term benefit of consumers, as it better reflects the benefits that customers receive from grid-delivered electricity. That is, a load customer that derives a substantial proportion of its electricity requirements from distributed generation does not benefit from the grid to the same extent as a load customer of similar size that lacks distributed generation.[482]

H.57 Half-hourly prices and generation/load volumes that are key inputs into vSPD are based on the volumes that the wholesale electricity market 'sees', ie, bid and offers, half-hourly settlement volumes and prices across the 250+ POCs. A 'traditional vSPD' approach automatically nets generation against load if a generator does not 'offer in' to the wholesale market. Thus, a traditional vSPD approach does not actually 'see' distributed generation that does not offer in – it 'sees' only a reduced level of demand at any POC that non-offering-in distributed generation sits behind.

H.58 However, where a generator offers in, often as required by the system operator who has some discretionary powers in this area, its generation volumes will not net off against any load. The offering-in generator will be separate and distinct from the load POC, and vSPD will calculate supplier surplus-related benefits to the extent that the generator benefits from transmission investments in the benefit-based charge.

H.59 Many of the generators that offer in to the wholesale market are grid-connected generators, and therefore would not net against load under a net vSPD approach. However, some of the generators are distributed generation or in some instances, grid-connected co-generation.

H.60 The Authority is proposing a net load approach for applying the benefit-based charge to the seven major investments – that is, to allow certain generation (primarily distributed generation), to net against the load in the network that generation sits behind. For example, a generator connected to Powerco's distribution network (ie, a distributed generator) would net off against Powerco's load and have the impact of reducing Powerco's consumer surplus or level of benefit from benefit-based investments. It is important to note however that a generator in, say, Powerco's Wairarapa network, would not be permitted to net off against a Powerco load in Powerco's Taranaki network, because Powerco's benefit from the grid in respect of its Wairarapa network relates to net load in the Wairarapa district only, independent of load or generation located in Taranaki.

H.61 To implement netting in vSPD, we have analysed the generators that offer in to the wholesale market, and applied judgement to determine which of these generators to net off against their respective loads.

H.62 We developed the following rules to support this judgement:

(a) Generation that is not grid-connected generation is to be netted against load at the relevant POC.

(b) Where there is insufficient load at the POC, netting is allowed against any load at the same physical location (physical location being identified by the first 3 letters of the POC, ie, ABY is Albany).

(c) Where there is not enough load to fully offset the generation at the same physical location, judgement is to be applied as to which POCs in the same network as the

482 See appendix B.

generation the remaining generation is to be netted against.[483] This is to ensure that the load customer's share of charges reflects the net benefit it derives from the grid.

H.63 For generators where judgement was required to determine whether netting should be permitted, we applied the following conditions:

(a) Partially embedded generation to be fully applicable for netting (100% netting permitted).

(b) Notionally embedded generation to be treated as grid-connected generation if it does not meet the definition of distributed generation in the Code.

(c) Grid-connected co-generation to be fully applicable for netting, but only against the grid-connected industrial load it is co-located with.

H.64 Prices are calculated half hourly in vSPD, giving rise to half hourly benefits (consumer surplus and producer surplus). In order to calculate net vSPD we made several manual netting adjustments across POCs and recalculated benefits. The recalculation of benefits was applied annually rather than half hourly, with revised benefits being calculated as a proration according to changes in annual quantities. For example, if demand at a POC was reduced by half due to a netting adjustment, the corresponding revised benefit was reduced by half. This approach makes two assumptions:

(a) first, that prices will not change on account of the netting

(b) second, that there is a linear relationship between volume and benefit.

H.65 While these assumptions do not strictly hold in practice, we consider these assumptions to be reasonable. The adoption of Net vSPD has reduced the estimated charges for the following distributors and direct-connects: Alpine Energy, Aurora Energy, Electricity Ashburton, Horizon Energy, Network Tasman, Norske Skog, NZ Steel, OtagoNet JV, Powerco, The Lines Company, The Power Company, Unison Networks, WEL Networks, Wellington Electricity, Westpower, and Whareroa Cogeneration Limited.

Q68. Do you agree with the approach we have taken to netting distributed generation? Do you agree with the application of the netting policy for particular generator(s)? If not, please provide information on particular generator(s) so that we can consider whether to amend the netting arrangements.

Investments initially subject to the benefit-based charge

H.66 The seven major investments that we propose to be initially subject to the benefit-based charge are listed at clause 13(b) of the proposed guidelines and in Table 15

H.67 As discussed in appendix B, the vSPD model has been used to allocate the costs of seven of the major investments commissioned since 2004 with an approved value over $50 million at the time of approval. For the remaining three investments that meet these criteria (North Auckland and Northland (NAaN), Otahuhu Substation Diversity and Upper South Island Reactive Support) the vSPD modelling was not able to identify material benefits for transmission customers commensurate with the costs of these investments.[484]

483 This would be POCs where there is no constraint expected between them and the relevant POC.

484 See appendix B.

Table 15 Investments modelled as being subject to the benefit-based charge

Investment	Reference
NIGU	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/north-island-grid-investment-proposal/
HVDC (Poles 2 and 3 combined)	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/hvdc-grid-upgrade/
LSI Renewables	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-renewables/
Wairakei Ring	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2008-gup/wairakei-ring-economic-investment-history/
BPE-HAY reconductoring	http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/bunnythorpe-haywards-a-and-b-lines-conductor-replacement-investment-proposal/
UNI dynamic reactive support	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/upper-north-island-dynamic-reactive-support-investment-proposal-archive/ This investment has been combined with the North Island grid upgrade investment so there is no dedicated vSPD run for this investment.
LSI Reliability	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/

H.68 The Authority decided to group Poles 2 and 3 of the HVDC on the basis that they essentially provide a single function. Note that we do not necessarily envisage that Transpower would be grouping new investments or new investments with existing investments for post-2019 investments. This is because parties considering whether to support a *new* investment would likely consider the incremental benefits and incremental costs of the new investment.[485]

Modelling scenarios provided

H.69 In addition to presenting modelling of the Authority's core proposal, we have provided some alternative options for parties to consider.

H.70 In the '2019 Proposal impacts modelling' Excel file, refer to columns W and X in the sheet titled 'Results'.[486] By changing the number selected in cells X3 and X9, parties can switch between the eight combinations of the options listed below.

485 That is, they would consider the benefits they get from the grid augmented by the existing investment against the benefits they get from the grid notLCE refunded includes LCE and residual LCE that is paid to Transpower. This is not the same as the LCE generated by the assets and investments, because some LCE is used to fund the FTR market in the first instance.

H.71 Benefit-based charge alternatives modelled:

(a) Net vSPD benefit-based charge, with variable VPO (the proposal)

(b) Net vSPD benefit-based charge, with fixed VPO at $500/MWh

(c) Traditional vSPD (no manual netting applied), with variable VPO

(d) Traditional vSPD (no manual netting applied), with fixed VPO at $500/MWh

H.72 Residual charge alternatives modelled:

(a) Gross volume on load (MWh pa)

(b) Gross anytime maximum demand (AMD) (the proposal).

Treatment of approved/committed distributed generation, entries and exits, and other adjustments

H.73 Our proposed charges, indicative charges and other impacts modelling are calculated using data from 1 July 2014 through to 30 June 2018. For historical benefit-based investments we consider that using historical data as modelling inputs provides a reasonable proxy for the future benefits parties will receive over the life of investments. For the residual charge we consider that historical data provides a reasonable proxy for customer size.

H.74 However, we will consider submissions where parties consider that the ex-post data or modelling outputs require adjustment. Examples of the types of matters we anticipate parties may wish to specifically consider in their submissions are:

(a) for an entering or exiting customer, or where an entering or exiting embedded customer, will cause or has caused, a material ongoing change in demand (or generation)

(b) where a material problem with the data is identified, for example, to address a 'double counting' issue.

H.75 There is an exception to the ex-post (historical) data only rule – where large new distributed generation/netting generation has been consented, is financially committed and is intended to be commissioned by the time a new TPM is in place. Where distributed generation/netting generation that met these conditions was identified, we reduced half-hourly load at the relevant POC in vSPD by the amount of generation expected (in essence, netting), before running vSPD. Note this relates to the benefit-based charge only as the residual charge is a gross charge, and thus no netting is permitted.

H.76 The Authority has identified two large distributed generators that met the conditions:

(a) We reduced net load at Kaikohe to account for the 31.5 MW Ngawha expansion, expected to be commissioned in 2020/21. However, the adjustment was subsequently backed out on the basis of this new generation being grid-connected. We did not calculate vSPD charges for the expected new grid-connected generation, because we do not expect Ngawha to receive net benefits from investments included in the benefit-based charge, and because we have not adjusted charges for entering or exiting customers.

(b) We reduced net load at Kawerau to account for the 20 MW Te_Ahi_O_Maui geothermal that is consented/financially committed and is expected to be in place by 2022.

Q69. Do you consider that the data or modelling outputs used in the impacts modelling (in particular, demand and generation volumes) should be adjusted? If so, please provide detailed reasoning/quantitative calculations.

Technical details of the TPM vSPD beneficiary simulation

H.77 For the TPM beneficiary simulation, we use data from July 2014 to June 2018 (four years of data) to estimate the benefit gained at each grid location (GXP/GIP).

H.78 In most cases, the factual case is the same as final pricing cases during this four year period. However, the value of lost load (VoLL) is adjusted in each case according to the respective counterfactual case.

H.79 In all simulations, Te_Ahi_O_Maui geothermal is added and assumed to be always at 90% capacity of 20 MW. Consistent with the netting policy, this generation is permitted to be netted off against load at Kawerau. vSPD calculates this automatically as Te_Ahi_O_Maui reduces load at Kawerau.

H.80 In all simulations, Ngawha2 stage 1 geothermal is added and assumed to be always at 90% capacity of 28 MW. Note, we decided to adjust NgaWha expansion on the basis that it would be grid connected and not distributed generation. The original adjustment has been manually backed out of the vSPD output files. This adjustment is undertaken using half-hourly data, in Excel.

Factual case simulation

H.81 This section describes the simulation of the factual case.

H.82 The factual case is the case where all grid upgrade projects (GUPs) have been built and are in service. The factual case is based on data from July 2014 to June 2018, with the exception of the Lower South Island (LSI) reliability project where the project was built and completed within the July 2014 to June 2018 timeframe.

H.83 For the special case of the LSI reliability project, transmission data is modified to simulate both the factual and counter factual cases (case without grid upgrade project).

H.84 The factual case is essentially the SPD case between July 2014 to June 2018 with new embedded generation added as mentioned above.

H.85 In case of HVDC, only the energy market is modelled.

H.86 In case of LSI reliability, transmission data is modified as if the LSI reliability grid upgrade project is in place.

No NI grid upgrade project (NIGU) simulation

H.87 The North Island Grid Upgrade (NIGU) Project to provide a secure supply of electricity to Auckland and Northland was officially completed in December 2012.

H.88 The factual case is final pricing case.

H.89 In order to approximately model the old grid before the NIGU project, the following was applied:

(a) The penalty for energy deficits is fixed to VoLL.

(b) The following transmission lines that are built for the NIGU project are removed from the system (PAK_T1, PAK_T2, PAK_T3, 'PAK_WKM_1 & 2, OTA_PAK_3 & 4, PAK_PEN_3 and HOB_PEN_1).

(c) Note that HOB_PEN_1 belongs to the North Auckland and Northland grid upgrade project. However, we needed to remove it to avoid overloading on the 110KV transmission line in the case of no NIGU.

(d) We removed the new NIGU substation (PAK2201, BHL2201, BHL2202).

(e) We added back the old 110KV substation at Pakuranga (PAK1101).

(f) We added back the old transmission lines and transfomers (ARI_PAK_1, PAK_PEN_1, OTA_PAK_1, PAK_T5 and PAK_T6)'

(g) Capacity and parameters applied for the old transmission lines and transformers are as of 21 July 2009.

(h) We redefined the upper North Island stability constraint as it was on 21 July 2009 with a limit of 1000 MW (or 1120 MW to be more optimistic).

(i) Ramp-rate constraints are ignored.

(j) A virtual generator is added at OTA2201 with 'unlimited' capacity and offered at either a fixed price of $500/MWh or at a variable price defined by historical prices at OTA2201.

No North Auckland and Northland grid upgrade project

H.90 The North Auckland and Northland (NAaN) project reinforced transmission into the Auckland Region and across the harbour to North Auckland and the Northland Region. It added a new 220 kV of transmission capacity to the National Grid by providing 37 km of underground cable between the Pakuranga, Penrose, and Albany substations.

H.91 The NAaN project was officially completed and the connection was commissioned in February 2014.

H.92 The factual case is the final pricing case with the same VoLL ($3000/MWh) as the counter-factual (no NAaN grid upgrade) case.

H.93 In order to approximately model the old grid before the NAaN grid upgrade, the transmission line between the Hobson street substation and the Wairau road substation (HOB_WRD_1) is removed so that demand in North Auckland and Northland is served through old transmission lines between the Otahuhu and Henderson substations.

No Wairakei Ring grid upgrade project simulation

H.94 The Wairakei Ring grid upgrade project was officially completed in June 2014.

H.95 The factual case is final pricing case.

H.96 In order to approximately model the old grid before the Wairakei Ring upgrade, the following is applied:

(a) The penalty for an energy deficit is fixed to VoLL.

(b) The new transmission line between Whakamaru and Wairakei (WKM_WRK_1) that was built for the Wairakei Ring project was removed.

(c) The capacity and parameters of the following transmission lines were adjusted back as they were on 21 July 2009. (ATI_OHK_1, ATI_WKM_1, OHK_WRK_1, THI_WKM_1, THI_WRK_1, PPI_THI_1).

(d) Note that THI_WKM_1, THI_WRK_1 and PPI_THI_1 are similar to WKM_PPI_WRK_1, WKM_PPI_WRK_2 and WKM_PPI_WRK_3 respectively.

(e) We re-applied old winter permanents constraints such as:

(i) ATI_OHK.1__WKM_PPI_WRK.1__:S__WKM_WRK__OHK__LN

(ii) ATI_OHK_1_W_P_1

(iii) ATI_WKM.1__WKM_PPI_WRK.1__:S__WKM_WRK__ATI__LN

(iv) ATI_WKM_1_W_P_B_z

(v) OHK_WRK_1_W_P_2A_z

(vi) OHK_WRK_1_W_P_A_z.

H.97 In order to simplify the simulation run, we applied the winter capacity and constraints for these lines in all trading periods.

H.98 Ramp-rate constraints are ignored.

H.99 A virtual generator is added at OTA2201 with ‘unlimited’ capacity and offered at either a fixed price of $500/MWh or at a variable price defined by historical prices at OTA2201.

Lower South Island renewables grid upgrade

H.100 The Lower South Island (LSI) renewables grid upgrade increases the capacity mainly on four transmission lines (LIV_WTK_1, AVI_WTK_1, CYD_ROX_1 and CYD_ROX_2).

H.101 The project was staged with CYD_ROX_2 capacity doubled in April 2014, CYD_ROX_1 capacity doubled in February 2015, AVI_WTK_1 capacity doubled in June 2015, and lastly LIV_WTK_1 capacity doubled in May 2016.

H.102 There are other works around this project, but these are ignored to simplify the simulation.

H.103 The factual case is final pricing case.

H.104 In order to approximately model the old grid before the LSI renewable upgrade, the following was applied:

(a) The penalty for the energy deficit is fixed to VoLL.

(b) The capacity and parameters of the following transmission lines were adjusted back as they were on 21 July 2009 (LIV_WTK_1, AVI_WTK_1, CYD_ROX_1 and CYD_ROX_2).

(c) We re-applied the old winter permanents constraints such as:

(i) AVI_WTK_1_W_P_1A

(ii) AVI_WTK_1_W_P_2A

(iii) CYD_ROX_1&2_W_P

(iv) LIV_WTK_1_W_P_1A

(v) LIV_WTK_1_W_P_2A.

H.105 In order to simplify the simulation run, we applied the winter capacity and constraints for these lines for all trading periods.

H.106 Ramp-rate constraints are ignored in counter-factual cases.

H.107 Virtual generation is added at OTA2201 and INV2201 with ‘unlimited’ capacity and offered at either a fixed price of $500/MWh or at variable price defined by historical prices at OTA2201 and INV2201.

Lower South Island reliability grid upgrade

H.108 The Lower South Island (LSI) reliability grid upgrade increases the transmission capacity in/out and through the Lower South Island 110 KV grid. The changes included increased capacity on the 220KV/110kV transformers at Halfway Bush (HWB), Roxburgh (ROX) and Invercargill (INV). A new 220KV/110kV transformer was also built at Gore (GOR).

H.109 The factual case is based on the final pricing case with new transformers added if they were not in place (ie, due to commissioning during the analysis time frame).

H.110 In order to approximately model the old grid before the grid upgrade, the following was applied:

(a) The penalty for energy deficit is fixed to VoLL.

(b) The 220kV/110kV transformers at HWB, ROX and INV were replaced by old transfomers based on data at or before July 2014.

(c) The 220kV/110kV transformers at GOR were removed.

(d) We re-applied old winter permanents constraints such as:

(i) EDN_INV_1_W_P_1

(ii) ROX_T10_W_P_1.

H.111 In order to simplify the simulation run, we applied the winter capacity and constraints for these lines for all trading periods.

H.112 Ramp-rate constraints were ignored.

H.113 A virtual generator was added at GOR0331 with ‘unlimited’ capacity, although this was not required in the simulation.

Bunnythorpe-Haywards transmission replacement

H.114 Two 220kV transmission lines were decommissioned and replaced with like-for-like transmission lines.

H.115 The factual case is based on the final pricing case.

H.116 In order to approximately model the grid without these two transmission lines, the following was applied:

(a) We removed the BPE_HAY_1 and BPE_HAY_2 transmission lines.

(b) The Wellington stability constraint limit was reduced to 700 MW.

(c) The Paraparaumu (PRM) substation was connected back to Pauatahanui (PNI).

H.117 Ramp-rate constraints were ignored.

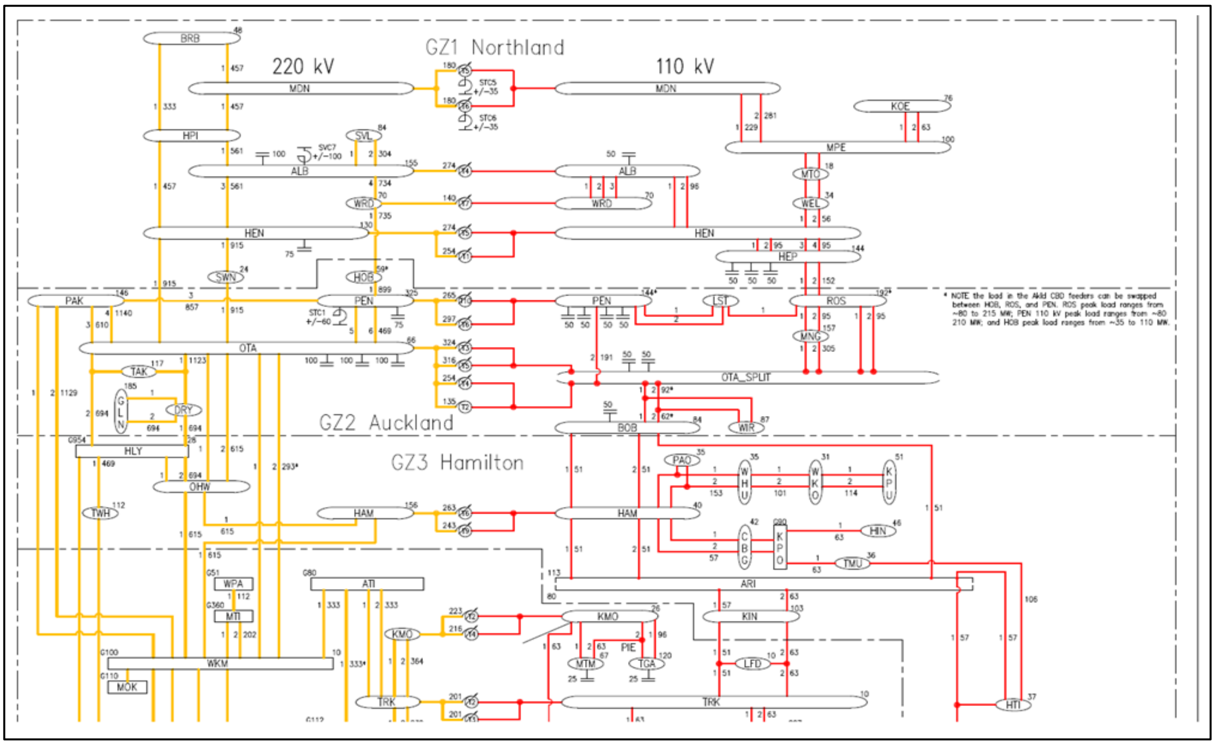
H.118 Virtual generation was not required.

Infeasibilities

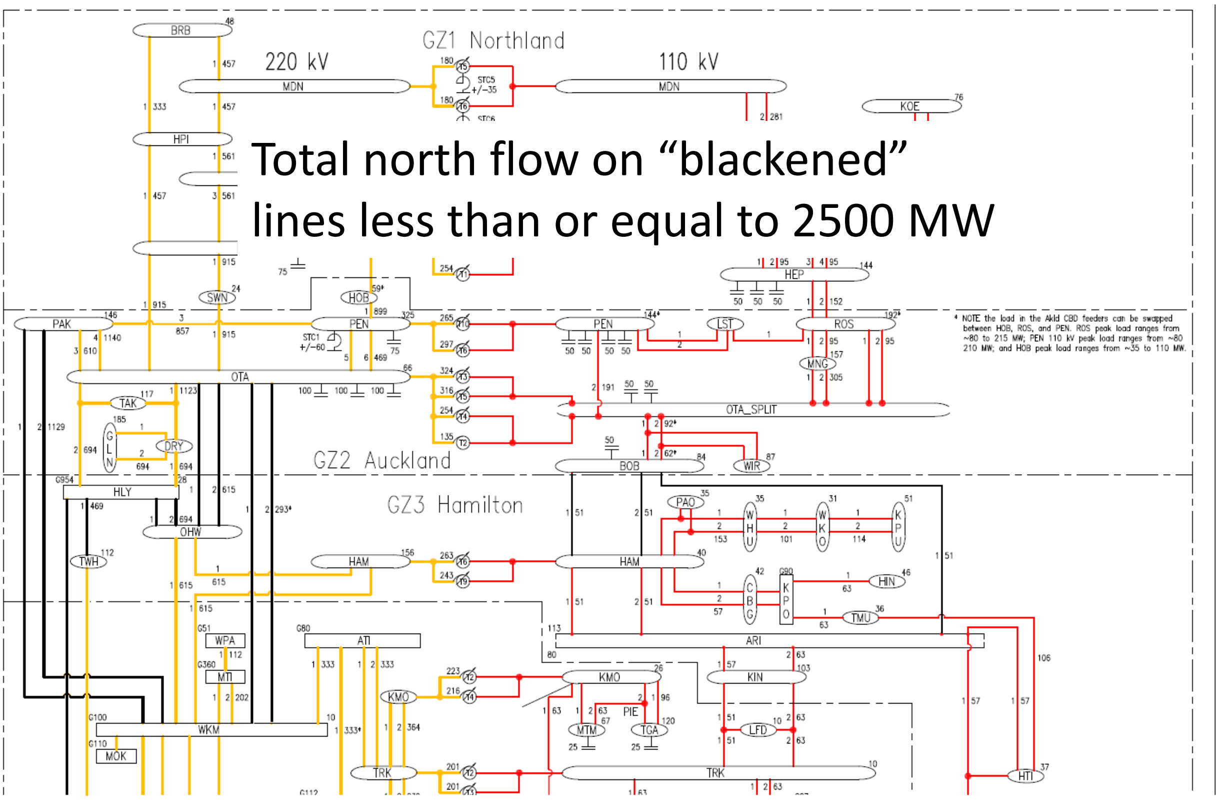
H.119 Grid configuration ‘with and without’ the transmission investment being assessed is modelled in vSPD to best approximate actual grid configuration, and the grid configuration that would be in place if the investment being assessed had not been undertaken. This involves taking out transmission assets and putting back in what was there before, with other adjustments, as required. Due to the complexity of grid configuration and its gradual development over time, vSPD sometimes calculates infeasible prices. In the final vSPD run we dealt with any remaining infeasible prices (prices above $10,000/MWh) by removing them in post processing.

An example of the application of the vSPD factual versus counterfactual simulation to the North Island grid upgrade

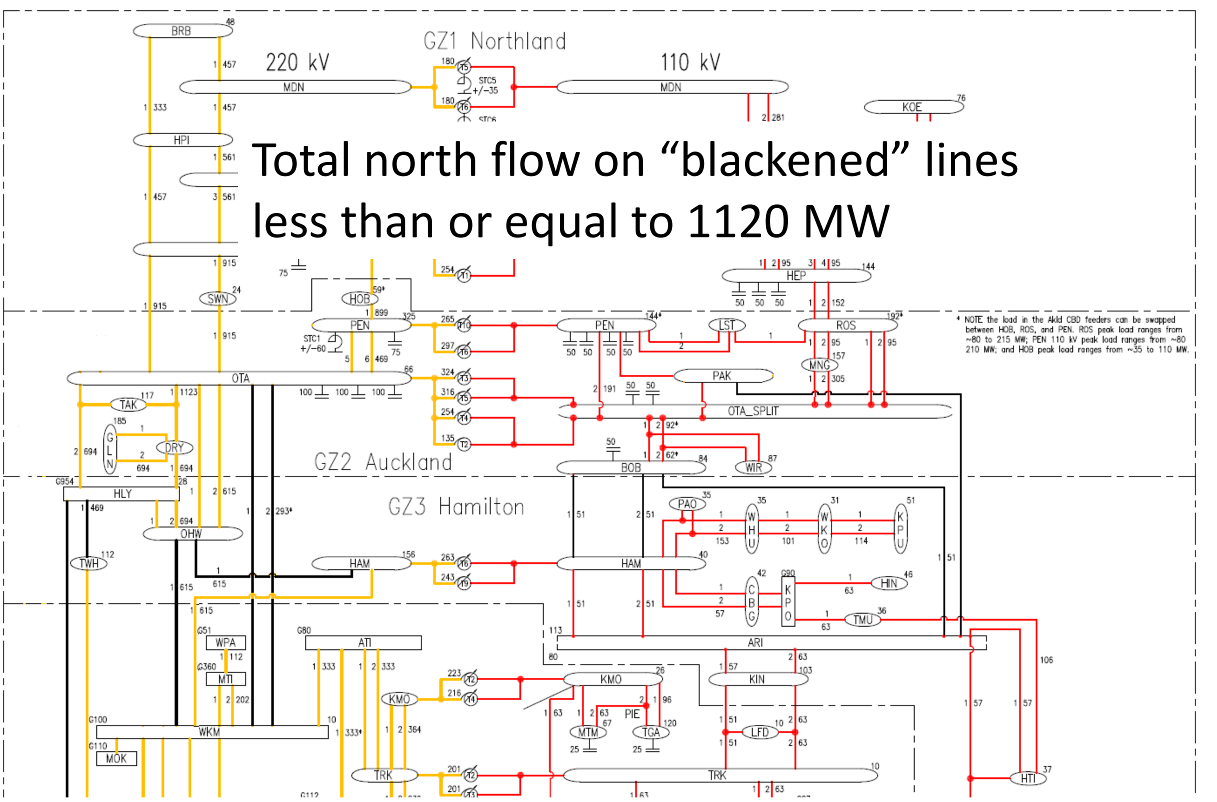
With NIGU



With NIGU constraint



Without NIGU



Modelling of indicative loss and constraint excess

H.120 Under the potential Code change on LCE that we are presenting for comment alongside the Authority's proposal, LCE revenue would be allocated to each of the connection assets and groups of assets or investments in the interconnected grid (including benefit-based charge investments and investments with costs recovered through the residual charge). LCE revenue is effectively treated as a partial refund of transmission charges to transmission customers. The allocation contemplated under the potential Code change would effectively reduce the revenue recovered in respect of each grouping of assets or investment in proportion to the LCE generated by that grouping of assets or investment.

H.121 The allocation of LCE to benefit-based investments has been modelled on an indicative basis and is available on the Authority's EMI website. This allocation has *not* been used in either the allocation of major investment costs in schedule 1 or the modelling of indicative charges for the proposal. The LCE allocation to benefit-based charge investments is provided for informational purposes only.

H.122 For this indicative modelling, the magnitude of the LCE funds used to offset transmission charges is sourced from information available on Transpower's website.[487] The LCE that could be refunded to benefit-based investments was identified using SPD, whereby each investment is defined as a bundle of SPD branches, and SPD calculates the LCE generated by each branch. A significant amount of LCE would be refunded to the HVDC ($7.5m) and the North Island grid upgrade ($5.5m). Total LCE is currently around $50m per annum.

H.123 The refund of LCE to connection assets was not modelled. Total LCE refunded to connection assets is normally around $5 to $6 million per year.

Q70. In addition to the specific questions above, do you have any other comments on the matters covered in Chapter 5 and this appendix H, including in particular: the indicative year-one transmission charges in chapter 5; and the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A).

[487] Aavailable at: https://www.transpower.co.nz/industry/revenue-and-pricing/pricing. LCE refunded includes LCE and residual LCE that is paid to Transpower. This is not the same as the LCE generated by the assets and investments, because some LCE is used to fund the FTR market in the first instance.