Transmission pricing methodology: CBA

Working paper

3 September 2013

Market Design

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1 Executive summary

Introduction

1.1 The Electricity Authority (Authority) is conducting a review of the Transmission Pricing Methodology (TPM) contained in schedule 12.4 of the Electricity Industry Participation Code 2010 (Code). The Authority is developing its response to submissions and cross submissions in relation to the consultation paper *'Transmission Pricing Methodology: issues and proposal'* dated 10 October 2012 (October issues paper) and to points raised in the May 2013 TPM conference.

1.2 In this regard, the Authority is considering how to respond to concerns and suggestions made in relation to the cost-benefit analysis (CBA) of the Authority's TPM proposal, which was detailed in Appendix F to the October issues paper – Cost benefit analysis of TPM proposal. The Authority will develop a second issues paper that is likely to materially alter the proposal that was in the consultation paper. The second issues paper will include a CBA for the revised TPM proposal (revised TPM proposal).

1.3 The Authority has prepared this working paper, which sets out a revised approach and method for the CBA. To ensure that it has fully understood concerns and suggestions made on the October issues paper, the Authority is releasing this working paper, and welcomes submissions on the Authority's proposed approach to the CBA.

Framework used for cost-benefit analysis

1.4 The CBA will use a 10-step process as follows:

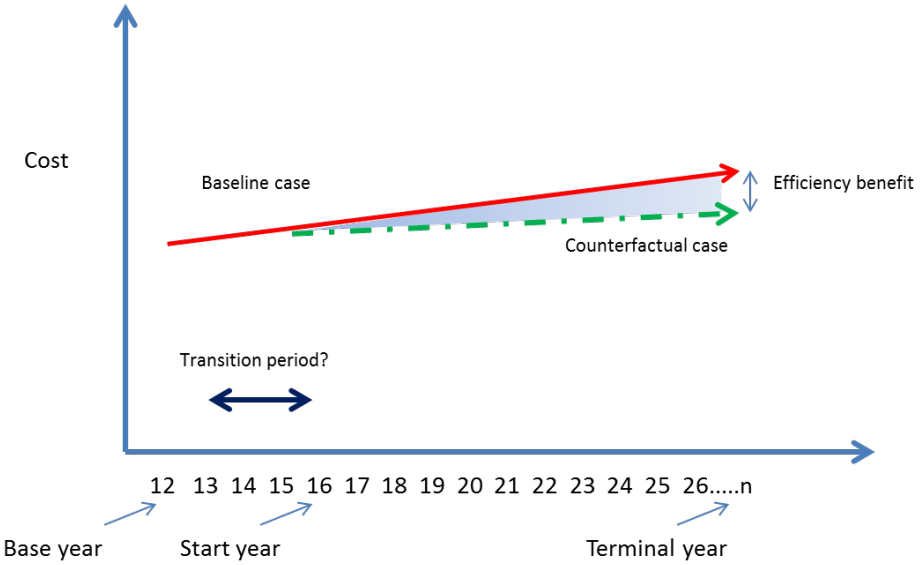
- define the problem
- select the options for assessment
- specify the baseline scenario
- identify the impacts of the options – negative (costs) and positive (benefits)
- where possible, quantify the impacts
- where possible, value the impacts
- adjust for differences in the timing of the impacts
- calculate decision criteria
- analyse the sensitivity of the results
- document the CBA.

Approaches to benefits estimation

1.5 Benefits estimation methods seek to quantify any change in economic efficiency between a status quo or baseline (factual) case and a reform or counterfactual case. (The counterfactual describes the action in question; in this case, changing the TPM. The factual describes no action; in this case, not changing the TPM.)

The conversion of quantifiable aspects of this change to monetary values is illustrated in Figure 1 below.

Figure 1 Illustration of change in economic efficiency



Source: Electricity Authority

1.6 The x axis represents time. Benefits estimation is forward looking. An historical base year is included as a reference for forecast values. In this example, a transition period represents the time required to change transmission pricing regulatory frameworks, and to design and implement new pricing systems. In this case, the estimation is *ex ante* and hence the counterfactual case is the lower line.

1.7 Various measurement units could be applied to the y axis. This could include unit or aggregate costs. It is likely that units used for the y axis would represent prices, rather than costs, since price data (for the base year) are typically more readily available than cost data.

1.8 The objective is to develop estimates of the present value of the area denoted by the blue triangle for each reform option (counterfactual) identified.[1] This requires developing estimates of both the forward baseline (red line) and the counterfactual case (green dotted line) for each reform proposal.

1.9 While there are various approaches to estimating reform benefits, a common element is the need to set out clearly the relevant features of:

(a) the baseline or status quo (the red line)

[1] More precisely, the objective is to estimate the present value of the difference between the baseline case and the counterfactual case – the triangle in the figure is illustrative.

(b) the reform counterfactual (the green line)

(c) an underlying causal model on the economic impacts (including any negative impacts) associated with moving from (a) to (b).

1.10 It may be appropriate to specify more than one counterfactual for a given reform option. This reflects uncertainty over the likely evolution of chosen indicators that are independent of the reform option, e.g. changes in supply and demand.

1.11 Four theoretical approaches to estimation of economic effects under counterfactuals can be identified. These include the following:

(a) Use of benchmarks. This is a form of 'top down' approach. Benchmarks represent data points estimating the effect of reforms of similar firms or similar industries in overseas jurisdictions, or in related or similar industries in the local jurisdiction.

(b) A structured or 'bottom up' approach. This may involve development of a comprehensive model of the electricity supply and demand system.[2]

(c) A treatment effects approach. This involves an econometric comparison between multiple real world states – for example sets of otherwise similar jurisdictions in which one set has undertaken an economic reform of interest while the other set has not.

(d) A bottom up approach referring to the entire economy. This approach would apply computerised general equilibrium (CGE) modelling and represents an extension of a structured approach beyond the electricity supply/demand system to regional and the entire national economy. It focuses on interactions between the energy sector and the broader economy.

1.12 In an extensive review of the relevant literature, the Australian Competition and Consumer Commission (ACCC) concluded that the key message from applied work is that no single approach is more legitimate, or better or worse, and there appear to be a diversity of approaches. This often involves 'pragmatic adaptations in response to contextual considerations'.[3]

Proposed approach to estimating benefits and costs

1.13 As discussed at the May 2013 TPM conference[4], it is proposed that benefits estimation would combine two approaches:

(a) A 'top down' approach drawing on benchmark data and evidence from similar types of reform on the possible quantum of incremental efficiency gains, including an increased rate of innovation.

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2 Unlike a general equilibrium model, this model need make no direct reference to interaction between the electricity sector and other aspects of the economy.

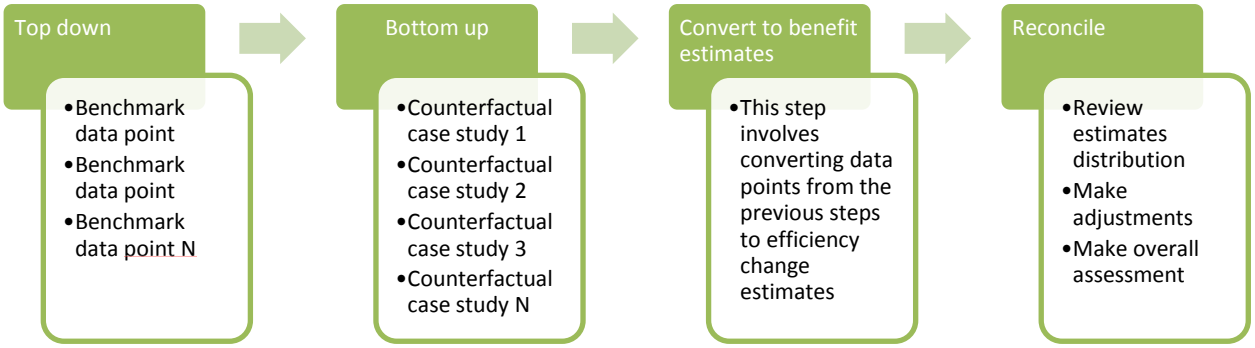
3 ACCC/AER, *op. cit.*, page 81.

4 See in particular page 118 of the transcript of the conference available at http://www.ea.govt.nz/our-work/programmes/transmission-work/development-of-the-transmission-pricing-methodology/

(b) A 'bottom up' approach, which clearly articulates and analyses the mechanisms by which identified features of a given reform option would lead to incremental efficiency gains.

1.14 The proposed process for estimating benefits is depicted in Figure 2 below. The data points from the two approaches would be converted to nominal dollar benefits estimates for the specified forecast period. Once discounted to present values, the result would be a distribution of benefits estimates for a given reform option. The range of benefits estimates would be reconciled to arrive at an overall benefits estimate for each substantive reform option.

Figure 2 Overview of proposed process to estimate benefits



Source: Electricity Authority

1.15 A top down approach with a suitably robust estimate of efficiency factors could provide a means of incorporating net dynamic efficiency benefits.

1.16 A bottom up approach is a useful exercise in that it requires the articulation of the causal model for the existence of efficiency benefits under a counterfactual. This means that the existence of efficiency benefits can be tested, not merely assumed. The mechanisms by which a TPM option could lead to efficiencies in upstream and downstream markets would be identified and analysed.

1.17 The proposed approach also means the factors that result in an option generating higher or lower benefits than an alternative can be identified and analysed. One or more case studies would be developed to assess any changes in supply chain costs (avoided capital and operating costs), in markets upstream and downstream from transmission, that are attributable to a specified TPM option.

1.18 One of the pitfalls when estimating efficiency is that estimates can be highly sensitive to assumptions of future demand and supply. Accordingly, alternative assumptions would be applied as part of the process set out above. The aim is to ensure the efficiency estimates take into account the sensitivity of these estimates to changes in supply of and demand for transmission services.

1.19 The data points from the two approaches would be converted to benefit estimates. A method for undertaking this conversion is outlined in this working paper and would be developed further in a revised CBA.

1.20 The process would yield a distribution of estimates. These would be reconciled in order to reach an overall benefits estimate.

1.21 Development of revised cost estimates would also apply a two part approach. The estimates would draw on evidence advanced in the course of submissions. Reference would also be made to benchmark data on reform costs.

1.22 In reconciling cost estimates, consideration would be given to the complexity and scope of reform, and the attendant implementation risks. This would include the possibility that a TPM option becomes more complex and costly to apply over time.

Responses to suggestions and criticisms

1.23 The proposed approach is intended to draw on the many useful suggestions made by interested parties about how the CBA of the revised TPM proposal should best be undertaken. It is also proposed that additional options to the revised TPM proposal would be identified and tested.

1.24 Top-down extrapolations from data in other studies would be scrutinised for relevance. Where extrapolations are deemed to be relevant, consideration would be given to whether normalisation or adjustments are required to address important differences in nature and scope.

1.25 Bottom-up analysis would also be undertaken to test the causal model underpinning the existence of any reform benefits. This would include the development of case studies.

1.26 The case studies would be developed in such a way as to evaluate the impact of possible detriments from the revised TPM proposal and options, highlighted in submissions. Consideration would for example be given to whether the revised TPM proposal and options could give rise to significant adverse risks or outcomes for generators and retailers, for example: inefficient trading and despatch decisions; deterrence of investment in peaking generation; higher prudential and working capital requirements; higher retailer costs and entry barriers, and possible reduction in retail competition.

1.27 CGE modelling may be useful if the benefits from a given TPM option are sensitive to interactions with the broader economy.

1.28 Consideration would also be given to identifying factors likely to affect the risk of dispute, given the characteristics of a given TPM option, compared with the status quo. Given the difficulties in quantifying the effects of the revised TPM proposal and options on the likelihood and scale of disputes, a possible approach could be to treat any identified gains (avoided costs of disputes) as an unquantifiable rather than quantifiable benefit.

1.29 This working paper represents an initial step toward developing the CBA that will be included in the second issues paper, with the revised TPM proposal and related draft guidelines (as referred to in clause 12.89 of the Code). That CBA would therefore be subject to consultation.

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2 Introduction

Background

2.1 The Electricity Authority (Authority) is reviewing the transmission pricing methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover costs of operating, maintaining, upgrading and extending the transmission grid.

2.2 The Authority considers that the current TPM can be improved so as to better meet 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.

Working papers

2.3 The Authority has decided to advance the process of reviewing the TPM by developing a second issues paper following consideration of submissions on the October issues paper[5] and information provided at the TPM conference held in Wellington on 29-31 May 2013.

2.4 Prior to developing a second issues paper, the Authority intends to develop and further consider key aspects of a revised TPM proposal through a series of working papers, which would form a key input into the second issues paper.

2.5 This paper is the first of the series of working papers identified by the Authority. This working paper outlines a revised approach that the Authority intends to apply to the cost benefit analysis of a revised TPM proposal that will be included in the second issues paper.

Other working papers

2.6 Other working papers the Authority has identified include:

(a) Definition of sunk costs – This paper will examine the extent to which the costs involved in the provision of electricity transmission services are actually “sunk” and the implications for transmission pricing.

(b) Avoided cost of transmission (ACOT) payments for distributed generation – This paper will investigate the benefits and costs that result from payment of ACOT to distributed generation. This paper will also determine whether or not ACOT payments to date reflect actual avoided costs of transmission.

(c) Use of loss and constraint excess (LCE) to offset transmission charges – This paper will explore submitter suggestions that the proposed use of LCE to offset transmission charges would distort the otherwise efficient wholesale market signals.

[5] Available from http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12/

(d) Approach to residual charge - This paper will consider whether it may be efficient to levy any residual charge on the basis of congestion rather than load during peak demand periods.

(e) Beneficiaries-pay approach – This paper will examine options for applying a beneficiaries-pay charge.

Decisions on the TPM

2.7 Section 32(1) of the Electricity Industry Act 2010 (Act) requires that provisions in the Electricity Industry Participation Code 2010 (Code) must be consistent with the Authority's statutory objective. The TPM is part of the Code, so any amendments to the TPM must be consistent with the Authority's statutory objective.

2.8 In order to assist the Authority to make decisions about the TPM consistent with its statutory objective, the Authority developed a decision-making and economic framework[6]. The Authority applied this framework to derive the proposal for the TPM that is set out in the October TPM issues paper[7]. After considering submissions on the October issues paper and the responses of parties to the Authority's questions at the May 2013 TPM conference, the Authority has decided to develop and release a second issues paper which will include a revised TPM proposal and related guidelines (as referred to in clause 12.89 of the Code) to be followed by Transpower in developing a new TPM.

2.9 In developing the second issues paper, the Authority will continue to be guided in its decisions by its TPM decision-making and economic framework.

2.10 The Authority's Consultation Charter[8] sets out guidelines relating to the processes for amending the Code and the Code amendment principles that the Authority must adhere to when considering Code amendments.

2.11 The Authority will make decisions about the development of the TPM according to its Code amendment principles and the Authority's statutory objective.

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6 Available from http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/

7 Available from http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12/

8 Available from http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/

3 Purpose of this paper

The purpose of this paper is to consult with participants and persons that the Authority thinks are representative of the interests of persons likely to be substantially affected by the TPM.

Submissions

3.1 The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with Working Paper – Transmission pricing methodology CBA in the subject line.

3.2 If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

3.3 Submissions should be received by 5pm on Tuesday 15 October 2013. Please note that late submissions are unlikely to be considered.

3.4 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

3.5 Your submission is likely to be made available to the general public on the Authority's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

4 Summary of response to criticisms and suggestions

4.1 A full summary of submissions on the CBA and a full transcript of the conference discussion are available at the Authority's TPM review project webpage[9]. This working paper provides an overview of key criticisms of the 2012 CBA.

4.2 Key criticisms made in submissions can be broadly divided into three categories: criticisms and concerns with the Authority's process in establishing the TPM proposal set out in the October issues paper, including the CBA (2012 CBA); criticisms and concerns with the methodological and conceptual underpinnings of the 2012 CBA; and the criticisms and concerns relating to technical aspects of the 2012 CBA. In addition to the criticisms raised in the submissions, a substantial number of suggestions and proposals were also made by attendees at the TPM conference.

4.3 Table 1 to Table 3 below are structured according to the three categories above and summarise the Authority's position and intended actions relevant to the matters raised.

[9] Available from http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/

Table 1 Overview 1: Process

	Suggestion/concern	Position	Action
P1	A new CBA should be undertaken	Agree	It is likely that the Authority will materially alter its TPM proposal, and accordingly a new CBA will be undertaken in order to facilitate the Authority meeting relevant requirements of the Electricity Industry Act 2010 and its Consultation Charter
P2	A new CBA should be developed in consultation	Agree	The Authority is required to undertake a CBA of its proposal. The Authority has decided to release a working paper on the CBA so interested parties are able to understand the Authority's intended CBA approach prior to release of the next issues paper. A CBA of the revised TPM proposal will be included in the second issues paper, which will be subject to consultation
P3	More reform options should be considered	Agree	The issues paper canvassed a range of alternatives for changes to the TPM. Multiple options are being considered in response to suggestions about how to better introduce and apply the

			decision-making and economic framework, particularly beneficiaries' pay charges. These will be the subject of working papers, and will be included in the second issues paper. The discussion of these options in the second issues paper will take into account comments received on the working papers
P4	The problem definition and CBA should be reconciled and integrated	Agree	A new problem definition statement will be developed that addresses issues raised with the previous problem definition alongside a CBA of a revised proposal, and the two will be integrated

Source: Electricity Authority

Table 2 Overview 2: Methodological and conceptual

	Suggestion/concern	Position	Action
MC1	A bottom up approach should be adopted	Agree in part	A bottom up approach will be adopted, alongside an enhanced top down approach
MC2	Benchmarks (for example from aviation mergers analysis) should be used with caution, take into account the specific nature of the electricity sector,	Agree	An enhanced top down approach would carefully consider the validity of benchmarks and may rely on an

	and the function and nature of transmission services		expanded data set
MC3	Existence of efficiency benefits should be tested, not merely assumed	Agree	Where possible, benefits will be quantified
MC4	Transmission pricing effects are limited to the timing and location of major transmission and generation investments	Initially disagree	A CBA will test this proposition but initial analysis contradicts it
MC5	Undertake CGE modelling to assess the welfare impacts of any aggregate excess historical investment in transmission assets	To be determined	CGE modelling could be applied to the extent reform benefits arise from interactions with sectors of the economy outside the energy sector
MC6	The avoided cost of disputes benefit category is problematic	To be determined	Further analysis will be undertaken of this cost category and, if appropriate, quantification undertaken
MC7	Does not take into account impacts for distributed generators	Agree that more work on this is required	A separate working paper is being prepared on this topic. This matter will be addressed in the CBA
MC8	Adverse consequences from reform need to be considered (generator behaviour, costs, investment appetite, retailer prudential and working capital costs, and retail competition)	Agree	Potential adverse reform consequences were considered in the previous proposal and will be further addressed in reform design and in the CBA
MC9	Reform costs exceed benefits	To be determined	The purpose of the CBA is to test whether reform benefits exceed costs
MC10	The CBA ignores the sunk cost nature of transmission assets	To be determined	A separate working paper is being

			prepared on this topic
MC11	The Transmission Pricing Advisory Group option has a higher benefit to cost ratio (BCR) and should therefore be ranked ahead of the Authority's preferred option	Disagree	In an economic CBA, the total welfare gain is the relevant criterion, not the BCR
MC12	The proposed reform option needs to advance the Authority's statutory objective	Agree	All of the Authority's CBAs are focused on this

Source: Electricity Authority

Table 3 Overview 3: Technical issues

	Suggestion/concern	Position	Action
T1	Need for clear empirical basis for derivation of chosen efficiency parameter	Agree in principle	The proposed method and approach for the CBA seeks to provide such a basis where possible
T2	Focused on dynamic efficiency but ignored static efficiency	Disagree	As with the previous proposal the CBA will address both types of efficiency
T3	Efficiency factor should be applied only to a subsection of sector revenue relating to transmission and generation	Disagree	There is no obvious reason to restrict the analysis to transmission and generation, since TPM reform also has significant downstream impacts
T4	A shorter time horizon than 30 years should be adopted	To be determined	The CBA will set out values for different time horizons
T5	There should be more analysis of the break-even point	Disagree	Break even analysis is not cost-benefit analysis, and the

			Authority is undertaking a CBA as referred to in the Authority's Code Amendment Principles
T6	Consideration should be given to the effect of reform on risk profiles, given the presence of 'long tail' risk	Agree	The CBA will take risk profiles into consideration
T7	A range of efficiency benefits estimates should be developed, given uncertainty over future demand for transmission and other exogenous factors	Agree	The CBA will seek to separate reform impacts from uncertainty over future demand for transmission, including by developing a range of efficiency parameters
T8	No benefits should be assigned from reallocating sunk costs	N/a	A separate working paper is being prepared on this topic
T9	Cost estimates should be revised upwards based on evidence adduced in submissions	To be determined	The CBA will draw on and critically review new costs evidence
T10	Implementation risks from reform scope and uniqueness should be accounted for	Agree	The CBA will consider implementation risks

Source: Electricity Authority

5 Overview of proposed CBA analysis framework

5.1 A proposed CBA analysis framework is set out in Table 4.

Table 4 CBA framework

1.	Define the problem	The current TPM can be improved so as to better promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. Specifically, the inefficiencies in transmission cost recovery under the status quo result in inefficient investment in, and operation of, the electricity industry.
2.	Select the options for assessment	A spectrum of options consistent with the Authority's Decision-making and Economic Framework paper, focusing on: • recovering the costs of transmission services on a more efficient basis; and • more emphasis on recovering transmission costs from the competitive sector (i.e. generators and retailers).
3.	Specify the baseline scenario	This includes defining/identifying: • the base year; • the current capabilities of affected organisations relative to process changes under TPM reform; • the duration of implementation preparation phase; • the forecast volume (high, low and medium cases); and • the scope for productivity change under status quo

4.	Identify the impacts of the proposal or options – negative (costs) and positive (benefits)	Benefit and cost categories would be linked to the impact of the relevant option. Similarly, transition and on-going cost categories would be linked to options and option impacts.
5.	Where possible, quantify the impacts	For benefits, this would draw on a combination of: • extrapolations from estimated efficiency gains from comparable reforms in comparable sectors ('top down'); and • estimates of possible avoided costs (benefits) in specific cases, attributable to transmission pricing reform ('bottom up'). To inform the development of a spectrum of efficiency parameters and analysis of the reasonableness of these parameters to inform judgments over the part of the spectrum selected for benefits quantification. For costs, this would draw on a combination of: • extrapolations from estimated reform costs for comparable reforms; and • estimates of possible implementation costs in specific cases, attributable to reform. To inform the development of a spectrum of cost estimates and to inform a selection of part of the spectrum for cost quantification.
6.	Where possible, value the impacts	Convert estimates of benefits and cost into values where this is not done directly.
7.	Adjust for differences in the timing of the impacts	Convert raw, moderated, benefit and cost estimates derived in the previous step into present values, thereby normalising for timing differences between options.
8.	Calculate decision criteria	Measure the net benefit of the proposal consistent with the Authority's statutory objective.
9.	Analyse the	Take into account uncertainty and intangible factors,

	sensitivity of the results	including via a sensitivity analysis.
10.	Document the CBA	Document CBA, including all assumptions, data sources, and a description of the methodology.

Source: Electricity Authority

5.2 The remainder of this document discusses how the Authority intends to undertake a CBA of a new TPM proposal by applying the components in Table 4 above. This paper will not discuss item 2 (selecting the proposal and options for assessment) as this will be addressed in the revised TPM proposal. Similarly the paper will not discuss item 10, documenting the CBA.

6 Define the problem

6.1 The October issues paper stated that the Authority considered that the current TPM can be improved to better meet the Authority's objective, and described the reasons for that conclusion, in particular, that the current TPM results in inefficient investment in and operation of the electricity industry.

6.2 Submissions and the discussion at the May 2013 TPM conference indicated that most parties did not agree with the Authority's problem definition and/or the Authority's reasoning as to why the current TPM is inconsistent with economic efficiency.

6.3 The Authority remains of the view that the reasons identified in the October issues paper are material, but considers that more explanation is required as to why the Authority considers the current TPM is inefficient, in particular, why it does not promote dynamic efficiency.

6.4 The following discussion seeks to explain at a high level how transmission pricing can impact on economic efficiency and how change to the TPM can improve economic efficiency. The intention is that the second issues paper will use the approach set out in this section to identify and describe the problems with the current TPM and why the Authority considers it is inefficient, and therefore does not promote the Authority's statutory objective.

6.5 The economic value offered by electricity transmission services is to transfer electricity from multiple remote generation sources ("upstream") to a large number of customer load centres ("downstream"). A large part of the value of transmission is predicated on electricity generation scale and location economies.[10] Large scale remote generation located close to a primary energy source may be lower cost than downstream distributed or local generation where primary energy has to be transported. Transmission thus facilitates competition in generation and retailing.

6.6 Transmission charges typically form around seven (7) per cent of final electricity prices in New Zealand. Transmission charges therefore have a significant effect on the point at which substitutes for electricity sourced from remote generation plus transmission are competitive or efficient.

6.7 There are numerous substitutes for transmission services. These include regional generation – for example generation in the Waikato does not require the inter-island HVDC link to serve Auckland customers. Similarly, a central Otago generator does not require the HVDC link to serve Christchurch customers. Other transmission substitutes include distributed generation; distributed storage

[10] Transmission also provides a reliability service by providing access to multiple generation sources and capacity.

(batteries); combined heat and power; and various forms of energy efficiency measures, demand management and demand response.

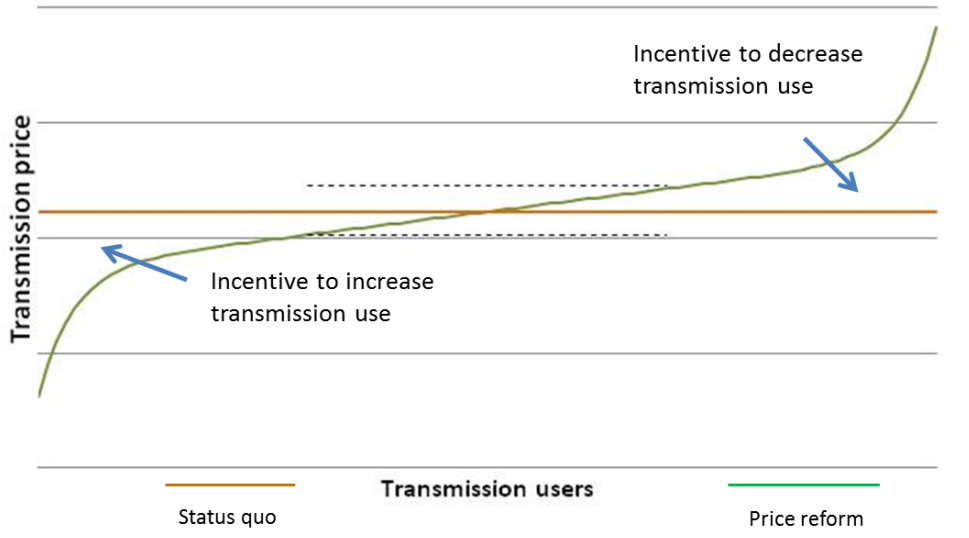
6.8 The existence of substitutes for both the upstream and downstream transmission users means that in the short term, but more so in the long term, demand for transmission services has a degree of sensitivity to transmission prices. A move toward more efficient transmission pricing creates incentives both to:

(a) Reduce transmission usage where there are more efficient (lower cost) substitutes.

(b) Increase transmission usage where there are less efficient (higher cost) substitutes.

6.9 This is illustrated in Figure 3 below, which provides an example of the possible effect of transmission pricing reform. The flat orange line is a simplified representation of the status quo or baseline,[11] while the green curve represents the outcome of a transmission price reform option. Transmission users are ranked from left to right in terms of increasing transmission prices over a typical 12 month period.

Figure 3 Stylised illustration of the effects of transmission pricing reform



Source: Electricity Authority

[11] No suggestion is made that current transmission prices do not differentiate at all between different transmission users.

6.10 The key impact of any reform of transmission pricing is to change transmission prices for transmission users (generators, retailers and direct connect customers). The change may be made through various combinations of spatial and temporal attributes. Service quality or other factors could also apply, for example, differences in demand for reactive power.

6.11 For example, in spatial terms, the curve could reflect changes in transmission prices at various grid exit points. In temporal terms, the curve could reflect changes in transmission prices at different times of the day or year. The curve is another way of representing the heat maps provided in the Authority's 2012 TPM consultation documents.[12]

6.12 In this stylised example, the total transmission revenue under the two cases is assumed to be equal - the curve is symmetrical. This is consistent with the fact that the Commerce Commission sets the maximum allowable revenue that Transpower may recover under the TPM - although over time, efficient transmission pricing should lead to a change in demand for transmission and therefore a change in the revenue recovered. Accordingly, any TPM proposal is independent from any proposals to change the approach to setting the transmission revenue cap.

6.13 If changes to the TPM are effective, transmission customers on the left hand side would experience a reduction in transmission prices, while those on the right hand side would experience an increase in transmission prices.

6.14 In the short term, efficient transmission prices could be expected to give rise to improved static efficiency. For example:

(a) Remote generators facing higher transmission costs may raise their bid prices in order to recover this increase.

(b) Within-region generators facing lower transmission costs may seek to improve their competitiveness by reducing their bids.

6.15 The overall impact of these changes over time would be to decrease dispatched output from generators with a high reliance on now higher cost transmission services, and increase output from generators with a low reliance on now lower cost transmission services. There would be an increase in productive efficiency because the same output would be produced with fewer inputs.[13] The effect would be to reduce the aggregate delivered cost of electricity.

6.16 While in the short term transmission substitutes may be limited, in the medium term there is a broader set of substitutes. For example:

(a) Generators and retailers that use higher priced transmission services have incentives to enter into new long term contracting arrangements (thereby

[12] See for example figure 7 from Appendix E: Using the SPD method to apply beneficiaries pay.

[13] In the short term this may result in unutilised transmission or generation capacity.

supporting financing of substitutes) that reduce use of higher priced transmission services where efficient substitutes can be made available.

(b) Conversely, generators and retailers that use lower priced transmission services have incentives to enter into new long term arrangements that increase use of lower priced transmission services where current substitutes are no longer efficient.

6.17 The short and medium term dynamics have the effect of changing the shape of the curve set out in Figure 3 above. This occurs to the extent that transmission customers on both the left and right hand sides of the graph migrate toward the middle. Demand for efficient transmission services increases, while demand for inefficient transmission capacity (compared with substitutes) decreases.

6.18 In the longer run, efficiently priced transmission services could contribute toward more substantial efficiency gains, for example:

(a) Generators avoid or defer expansion and/or refurbishment of inefficient generation assets.

(b) Generators bring forward expansion and/or refurbishment of efficient generation assets.

(c) There is a slower take up of downstream substitutes where avoided upstream plus transmission costs are reduced.

(d) There is a faster take up of downstream substitutes, where avoided upstream plus transmission costs are increased.

(e) In response to a reconfiguration of supply and demand, distributors may similarly bring forward efficient or defer inefficient distribution upgrades.

(f) There may be lower carbon costs than otherwise, for example if efficient transmission prices increase incentives to use or invest in local renewable generation or combined heat and power generation, instead of remote thermal generation plus transmission.

(g) There is stronger competition in generation and retail markets than otherwise, so there may be some increase in competitive pressures on retailer operating costs and margins.

6.19 A further class of benefits from more efficient transmission pricing may arise where the pricing system interacts dynamically with developments in upstream and downstream markets. Examples of such developments might include:

(a) Future increases in carbon emission permit prices and changes in primary energy costs (for example natural gas prices).

(b) Closure of a major industrial customer may make a new transmission investment, to enable a remote generator to access new downstream customers, efficient compared with substitutes.

(c) Reductions in the cost and increases in the efficiency of transmission substitutes, for example technical and market breakthroughs in distributed generation and storage, and increased penetration of combined heat and power.

6.20 The various downstream and upstream changes outlined in previous paragraphs could affect long term demand for transmission services via:

(a) Avoidance of excess demand for a transmission service (due to the service previously being under-priced) may efficiently defer the point at which augmentation of the service is considered in transmission planning processes.

(b) Avoidance of suppressed demand for a transmission service (due to the service previously being overpriced) may efficiently bring forward the point at which augmentation of the service is considered in transmission planning processes.

6.21 If changes to the TPM have the intended efficiency impact, then it could lead to significant changes in the transmission planning outlook. The forecast requirement for (now) inefficient transmission capacity augmentation could be deferred and reduced. Conversely, the forecast requirement for (now) efficient transmission augmentation could be increased and brought forward.

6.22 Such changes in demand for transmission services presuppose no change to existing regulatory decision making frameworks for consideration of new regulated transmission investments. By influencing relative demand for different transmission services, transmission pricing reform can influence demand for future regulated transmission services before the point at which regulated investment decision processes would be initiated.

6.23 It is possible that transmission reform could indirectly improve the efficiency of regulated transmission capital investment decision making processes. This could occur to the extent transmission users are more likely, following reform, to present additional information and data on efficient substitutes (both upstream and downstream) during the regulatory decision-making process for a transmission investment proposal under the Transpower Capex Input Methodology.

6.24 As a result of the developments outlined above, overall industry innovation and total factor productivity (TFP) could improve at a faster rate than otherwise. TFP is a variable, which accounts for effects in outputs that are not explained by changes in the volume of inputs, such as capital and labour.

6.25 As TFP is a residual it may be inferred but cannot be measured directly. Accordingly a possible proxy would be a change in the rate of change in unit prices, once other factors such as quality (including service reliability) have been normalised.

6.26 Accordingly any structural improvements in TFP could be reflected in long term average end user prices rising at a slower rate than otherwise. The overall effect of the dynamics described above could be a reduction in aggregate delivered electricity prices relative to the status quo. In other words, TPM reform could enhance economic efficiency, rather than merely transferring wealth between different types of transmission customer (or between regions).

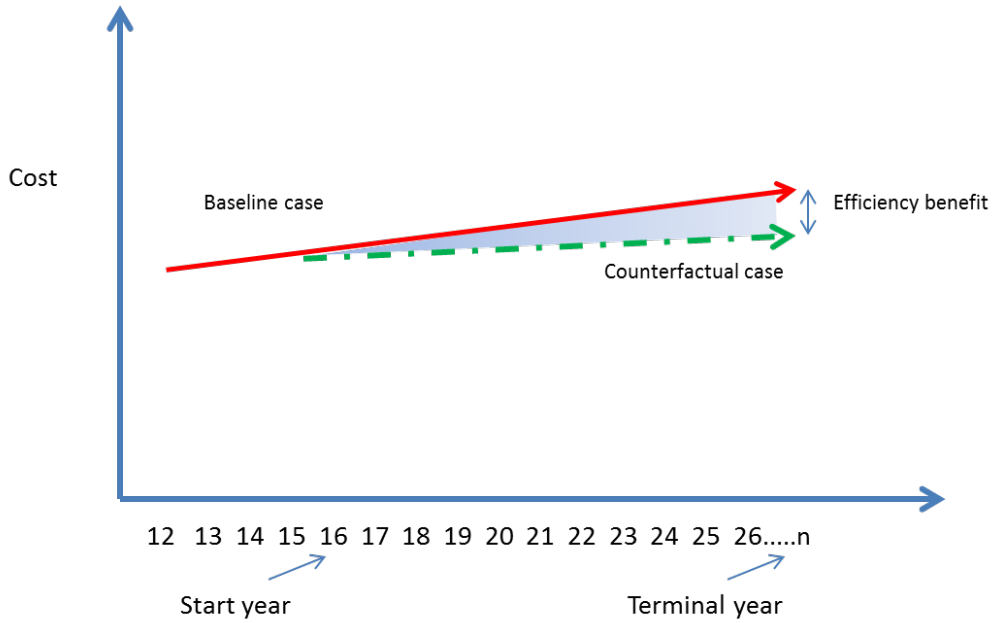
6.27 An aggregate reduction in delivered electricity prices, without any diminution in service quality, would advance the Authority's statutory objective. Reform could therefore promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long term benefit of consumers.

7 Specify baseline scenario

7.1 The previous section described how transmission pricing reform could give rise to improvements in economic efficiency. This section discusses methods and approaches to estimating reform benefits.

7.2 Benefit estimation methods (for ex ante purposes) seek to quantify the change in economic efficiency between a status quo or baseline case and a reform or counterfactual case. (The counterfactual describes the action in question; in this case, changing the TPM. The factual describes no action; in this case, not changing the TPM.) The conversion of quantifiable aspects of this change to monetary values is illustrated in Figure 4 below.

Figure 4 Illustration of change in economic efficiency



Source: Electricity Authority

7.3 The x axis represents time. Benefits estimation is forward looking. An historical base year is included as a reference for forecast values. In this example, a transition period represents the time required to change transmission pricing regulatory frameworks, and to design and implement new pricing systems. In this case, the estimation is *ex ante* and hence the counterfactual case is the lower line. An *ex post* estimation is similar in principle, except that here the counterfactual case would be the red line.

7.4 Various measurement units could be applied to the y axis. This could include unit or aggregate costs. Under an *ex post* benefits estimation, it is more likely that

units used for the y axis would represent prices, rather than costs, since price data are typically more readily available than cost data. Prices could also be applied to an ex ante estimation, reflecting the availability of price data on which to base the forward forecast.

7.5 The objective is to develop estimates of the present value of the area denoted by the blue triangle for each reform option (counterfactual) identified.[14] This requires developing estimates of both the forward baseline (red line) and the counterfactual case (green dotted line) for each reform proposal.

7.6 Both sets of lines are typically presented as upward sloping, where the rate of increase in real price rises is lower under the counterfactual. Benefits could also occur where the lines are downward sloping – where the rate of decline in prices is greater under the counterfactual. The important factor in either case is the present value of the difference.

7.7 While there are various approaches to estimating reform benefits, a common element is the need to set out clearly the relevant features of:

(a) the baseline or status quo (the red line), which will be the same irrespective of the counterfactual

(b) the reform counterfactual (the green line)

(c) an underlying causal model on the economic impacts (including negative impacts) associated with moving from (a) to (b).

7.8 The degree of confidence in the results of the evaluation, whatever the particular method applied, will reflect the confidence in the underlying causal model.[15] An initial description of a causal model was set out in the previous section.

7.9 For the reasons set out in the previous section, the unit of analysis would be the final prices faced by consumers.

7.10 In order to articulate the underlying causal model, it may be useful to split the retail price into its various building blocks.[16] There is, however, no clear basis for limiting the analysis to transmission costs, or to transmission plus generation costs. Similarly, there is no clear basis for limiting the analysis to the timing and location of a small set of large scale transmission and generation investments.

7.11 It may be appropriate to specify more than one counterfactual for a given reform option. This reflects uncertainty over the likely evolution of chosen indicators that are independent of the reform option, e.g. changes in supply and demand.

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14 More precisely, the objective is to estimate the present value of the difference between the baseline case and the counterfactual case – the triangle in the figure is illustrative.

15 See page 61 of *'Evaluating infrastructure reforms and regulation; a review of methods',* working paper No. 2 / August 2010, Australian Competition and Consumer Commission.

16 *Ibid*., page 76.

8 Identify the impacts

8.1 Three theoretical approaches to estimating economic effects under counterfactuals can be identified. These include the following:

(a) Use of benchmarks. This is a form of 'top down' approach. These benchmarks represent data points on the estimated effect of reforms of similar firms or similar industries in overseas jurisdictions, or in related or similar industries in the local jurisdiction. Criticisms of this approach are that benchmarks may not be appropriate, or may require extensive adjustment and normalisation to be valid. In addition, it fails to test the causal model underpinning the theoretical and factual underpinning for the existence of efficiency benefits.

(b) A structured approach. This is a type of 'bottom up' approach. This involves specifying a system of equations that contain parameters and variables that attempt to capture behavioural relationships and specify causal relationships between variables. Criticisms of the structural approach are that it is data-intensive, requires strong assumptions, can be overly deterministic, and tends to under-estimate unknown factors such as future innovation and dynamic efficiency.

(c) A treatment effects approach. This involves an econometric comparison between multiple real world states. An example would be where there are a number of jurisdictions where the reform option has been implemented while in others something similar to the status quo is in place.

8.2 In an extensive review of the relevant literature, the Australian Competition and Consumer Commission (ACCC) concluded that the key message from applied work is that no single approach is more legitimate, or better or worse, and there appear to be a diversity of approaches. This often involves 'pragmatic adaptations in response to contextual considerations'.[17]

8.3 A treatment effects approach does not appear to be applicable to the review of the TPM. Among other things, this is because the New Zealand transmission system and regulatory frameworks have a number of unique characteristics.

8.4 Computerised General Equilibrium (CGE) models represent a further possible method. CGE models may be seen as an extension of the bottom up or structured approach above, which rely on partial or sector specific equilibrium modelling.[18] CGE extends partial modelling to include the effects of reform on the entire economy. This may include possible dynamic or multiplier effects. For example if reform led to a material reduction in electricity prices in some regions,

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17 *Ibid.*, page 81

18 Note that electricity industry transmission substitutes, including demand side and distributed generation and storage activities, are already being addressed in non CGE approaches identified above.

this may result in a substantial increase in the size and value of energy intensive industries in those regions, with consequent flow-on effects for regions and the national economy.

8.5 CGE modelling may also be useful to test whether an option would promote the objective of the review of the TPM of promoting overall efficiency of the electricity industry for the long-term benefit of consumers by encouraging more efficient alternatives to electricity supply and consumption to meet energy demand. Examples might include substitution of electricity by gas, coal or by more energy efficient buildings and appliances.[19]

8.6 CGE models can be powerful informative tools, capable of providing coherent answers to complicated questions. CGE models can also have some drawbacks including a high level of complexity, lack of transparency, high cost and significant lead times.[20]

8.7 The benefit categories applied will be reviewed to ensure they are robust and relate to articulated connections to direct impacts flowing from pricing reform components. It is expected that the main category of reform benefits will continue to relate to interconnection/HVDC pricing reform, as these represent the bulk of regulated transmission cost recovery.

8.8 Reform benefits will be quantified separately for other major components of reform, consistent with the design of the option and the assessment of its impacts in the main assessment of proposals.

8.9 The benefit category *Adjustment for avoided costs of disputes* would be reconsidered. This reflects the difficulty in applying the methodology and approach outlined to the estimation of any benefits from the avoided cost of disputes.

8.10 It is proposed there is no change to cost categories. There would continue to be just two cost categories:

(a) incremental transition costs

(b) steady state operating costs

8.11 These would, however, be broken down into more detailed costs, especially for the purpose of developing modelled 'bottom up' cost estimates. The more detailed modelling would consider the major tasks and activities for the relevant parties including the party or parties that implement the reformed transmission pricing system, on the one hand, and the parties that are directly liable for paying transmission charges, on the other.

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19 Note these factors should also be taken into account in partial equilibrium modelling.

20 *Ibid*., page 111.

8.12 Figure 5 below sets out the conceptualisation for costs estimation. At the high level there are one-off transition costs incurred up to the start date. In this case, the start date is assumed to be in April 2016. Note that the Authority is yet to determine a start date for pricing reform. The steady state operating costs are assumed to begin from the start date and to continue until the terminal year.

Figure 5 Conceptualising costs estimation

Source: Electricity Authority

8.13 There is of course a series of judgments required over the scale of both high level cost categories. This is discussed in the following section.

8.14 Adverse consequences from reform will be assessed in the quantification process set out in the following section. Any adverse consequences would not be represented as new cost categories. This means the costs side of the analysis is limited to reform transition and on-going costs.

8.15 To the extent there is clear evidence as to the existence of detriments from a given reform proposal, this would be represented by explicit downward adjustments to efficiency estimates. This is because detriments are not readily analysed in the context of assessing the transition and steady state operating costs outlined above. It is preferable to analyse these in the context of the causal model of the impacts of TPM reform of the type outlined in section 6 above.

8.16 In broad terms, the second level cost categories defined in the 2012 CBA would be applied in a new CBA. This reflects an assessment that concerns over the costs quantification relate mainly to the cost estimates used for the identified cost categories rather than costs being omitted.

8.17 Incremental one-off costs would therefore be calculated according to the following categories:

(a) detailed TPM design, including costs associated with making Code amendments to implement changes to the TPM[21]

(b) aggregate central systems

(c) aggregate participant systems

8.18 The key assumptions including number of participants, and cost per participant would be derived in accordance with the process set out in the following section.

8.19 Ongoing costs would include:

(a) ongoing operation of the transmission system billing engine

(b) ongoing operation of the systems used by transmission customers to verify transmission charges and recover these costs from third parties (e.g. end user customers)

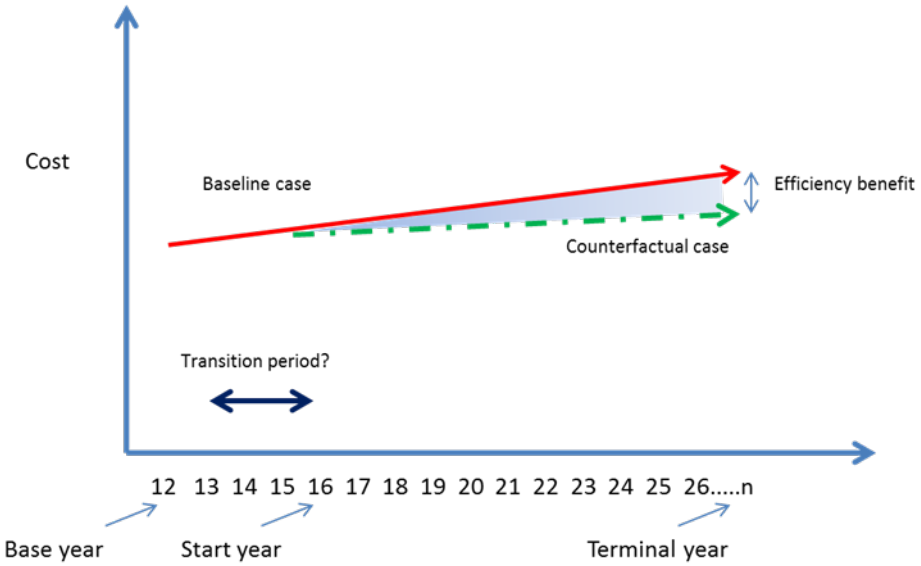
8.20 The ongoing costs estimate would need to take into account the possibility that under a given option the transmission pricing system could become more complex and costly to operate over time.

[21] Note this does not include the costs incurred by the Authority that would also be incurred by the Authority if it decided against making changes to the TPM, ie the costs of these working papers, consultation papers, Board meetings, decision papers etc. The additional costs would be the costs involved in drafting of Code, consultation on the draft Code (as opposed to draft guidelines for the TPM), approval of and gazetting of the changes to the Code.

9 Quantify impacts

9.1 In line with the previous discussion, the proposed quantification framework requires estimating a revenue baseline forecast and a counterfactual case for each substantive reform option. This is illustrated in Figure 6 below.

Figure 6 Conceptualising efficiency benefits estimation



Source: Electricity Authority

9.2 Uncertainties affecting the parameter that sets the slope of the baseline case (depicted by the red line) include:

(a) Future trends in peak and annual volumes – relevant factors include: demographics; energy efficiency; potential for substantial displacement of remote generation and associated transmission; demand for future metals processing and other energy intensive sectors, and a range of other factors.

(b) Future trends in total revenues – uncertainties around future volumes will influence unit prices and hence changes in total revenues.

(c) Historical rates of productivity growth (which may vary for different components in the electricity supply chain) and the scope for this to continue/decrease/increase, in the absence of transmission pricing reform.

9.3 The parameter that sets the slope of a counterfactual (green dotted line) relative to the base year is also subject to substantial uncertainty. This includes:

(a) the timing of final decisions on transmission pricing reform

(b) the duration of the transition period between final decisions and the full implementation of new transmission pricing arrangements

(c) the start year

(d) the specific content of a given TPM option (what are the efficiency effects of the option in question?)

(e) the impact of a given TPM option (how does the market respond?)

(f) the possibility of adverse consequences (to what extent are there detriments or inefficiencies from the option, and if so, how material are they?).

9.4 A further complication is the interplay between the baseline and counterfactuals. For example, in some scenarios, the red line is more dynamic – there is a higher level of demand or revenue growth. In a more dynamic environment, there may be greater scope for efficiency gains, in which case there may be greater opportunity for the green and red lines to diverge. Conversely, in a more static environment, there may be less scope for efficiency gains, and less opportunity for the green and red lines to diverge.

9.5 The development of a revenue base would involve the following steps:

(a) Gathering data on the key parameters for an historical base year. The proposal is to update the base year to the calendar year ending 31 December 2012. Data will be sourced from the Ministry of Business, Innovation, and Employment data file for energy when it becomes available.[22]

(b) The baseline parameters will be carried forward for the forecast period to derive a forecast revenue base. At least three forecast cases will be developed to highlight the effect of uncertainty over a number of factors, as identified in paragraph 9.2 above.

9.6 The development of the baseline forecast would include consideration of historical volume and productivity trends. The latter will focus on components within the supply chain. It will take into account other relevant factors including changes in service quality (notably reliability and demand profiles) and the average asset age profile (subject to data availability). This reflects the fact that proxies for total factor productivity (TFP) can appear to fall in conditions where there is a major asset replacement program, declining load factors, or rising primary energy costs. This would also ensure that TFP estimates would not be influenced by primary energy trend factors (such as changes in the wellhead cost of domestic gas production).

[22] The 2011 energy data file was released in August 2012.

10 Value the impacts

10.1 Substantial additional evidence and analysis would be developed for a revised CBA to develop a range of benefit and cost estimates for identified options. This would include consideration of multiple future scenarios, additional empirical evidence and case studies of changes to supply chain costs that could reasonably be attributed to transmission pricing reform. This will give rise to a distribution of efficiency estimates and provide a sounder basis for comparing benefits relative to costs.

10.2 Further data on comparable pricing and other regulatory reforms will be sought to inform high level estimates of change in productivity rates that can be attributed to reform. Data on comparators will be sought in relation to efficiency improvements:

(a) In the New Zealand energy sector in previous pricing reforms including locational and time of use/congestion pricing reform.

(b) From pricing reform from relevant energy markets internationally, including both location and time of use pricing reform.

(c) In other infrastructure sectors. Possible examples could include road user charges, airport movement charges, or other pricing reforms.

10.3 For all benchmark comparators, consideration will be given to the extent there were latent efficiency gains prior to reform – were the opportunity costs pre-reform similar? Other reform or industry specific factors would also be considered in order to normalise or adjust a crude extrapolation from comparator estimates.

10.4 In addition to the top down approaches above, further 'bottom up' data points would be developed from case studies of potential short and longer term responses to transmission reform, to inform "granular" productivity improvement estimates (taking into account overall effects of reform), for example:

(a) Upstream responses – for example avoided costs from improved utilisation of remote generation such as Clyde. This would draw from modeling and analysis in Appendix C and D of the 2012 consultation paper.[23]

(b) Downstream response where transmission charges decrease – for example efficient upward demand side response, greater use of remote generation, possible avoided fuel and inefficient distributed generation and storage (henceforth DG/DS) investment costs.

[23] For clarity, note these appendices are concerned with estimating private benefits from alternative transmission arrangements with respect to existing transmission assets, and hence are not comparable with a forward looking economic CBA.

(c) Downstream response where transmission charges increase – for example efficient downward demand side response, decreased use of remote generation, faster uptake and use of DG/DS.

(d) Effects on long term transmission investment – for example to the extent pricing reform stimulates efficient remote generation; it may stimulate efficient transmission investment. Alternatively, to the extent reform reveals excess transmission, remote generation output and capacity and an overvalued transmission regulated asset base, it may defer transmission investment and bring forward DG/DS.

10.5 Selection of a revenue base for estimating benefits requires consideration of the scope of reform options impacts. The proposed revenue base reflects the causal framework set out in section 6; transmission pricing reform could have effects on both the downstream and upstream sides of transmission services. Further, it reflects an initial view that the scope of efficiency benefits may not be limited to the timing or location of large scale transmission or generation investments. Furthermore, it reflects a view that, under some future supply/demand cases, distributed generation and storage could be competitive with remote generation plus transmission capacity for a substantial portion of demand in some regions.

10.6 A further important feature of focusing on final consumer prices, is that consumer prices are clearly highly relevant to the Authority's statutory objective. Accordingly, estimating the impact of reform on consumer prices provides a direct means of testing the extent to which a given reform proposal does or does not promote the Authority's statutory objective.

10.7 There are of course forecast cases where the revenue denominator declines rather than increases. This possibility should not be discounted at the outset. The possibility does not, however, invalidate the proposed approach, since this is concerned with the size of the efficiency factor, not the slope of the revenue base forecast.

10.8 An aspect that may need to be considered arises from the possibility that a new TPM reveals, leads to, or exacerbates a universal reduction in the demand for transmission services in the future. This is the possibility there is already excess transmission capacity relative to future demand and supply conditions.[24] This could arise where investment in capacity is prudent in the expectation of long term demand growth but imprudent if this expectation turns out to have been unfounded (i.e. expected future demand and supply conditions do not eventuate).

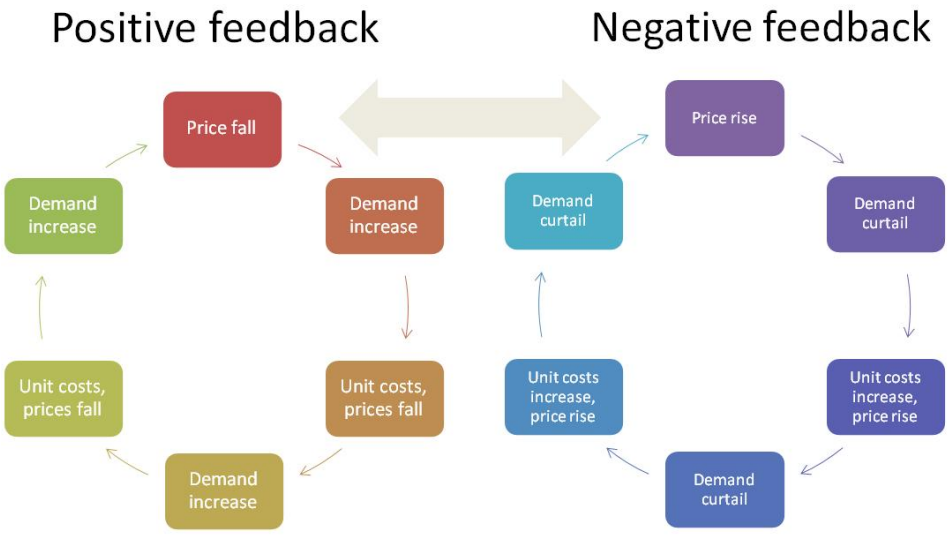
10.9 A problem arises because, under regulatory frameworks beyond the scope of TPM reform, any reduction in peak transmission demand or throughput does not lead to a reduction in the total regulated transmission revenue cap. If demand is lower than forecast, any revenue shortfall leads to a subsequent upward

[24] See especially comments made by NZIER at pages121 and 122 of the TPM conference transcript for day 1.

adjustment to prices. Customers, not networks, bear the cost of asset stranding. The trade-off is that this results in lower financing costs than otherwise, and these lower costs are reflected in regulator assessments of efficient long term costs.

10.10 In combination, existing transmission revenue setting frameworks and current transmission pricing approaches could inefficiently increase the competitiveness of transmission substitutes. This could contribute to a self-reinforcing negative cycle (for transmission demand) in which as transmission prices increase, more customers switch to substitutes. This cycle could be exacerbated if negative feedback interacts with positive feedback and prices for transmission substitutes rapidly fall, as has notably been the case for rooftop photovoltaic (PV) generation. The initial feedback leads to a reduction in throughput, requiring a second round increase in unit prices. This could set off a second round of customer switching to transmission substitutes, and so on, as illustrated in Figure 7 below.

Figure 7 Positive and negative feedbacks

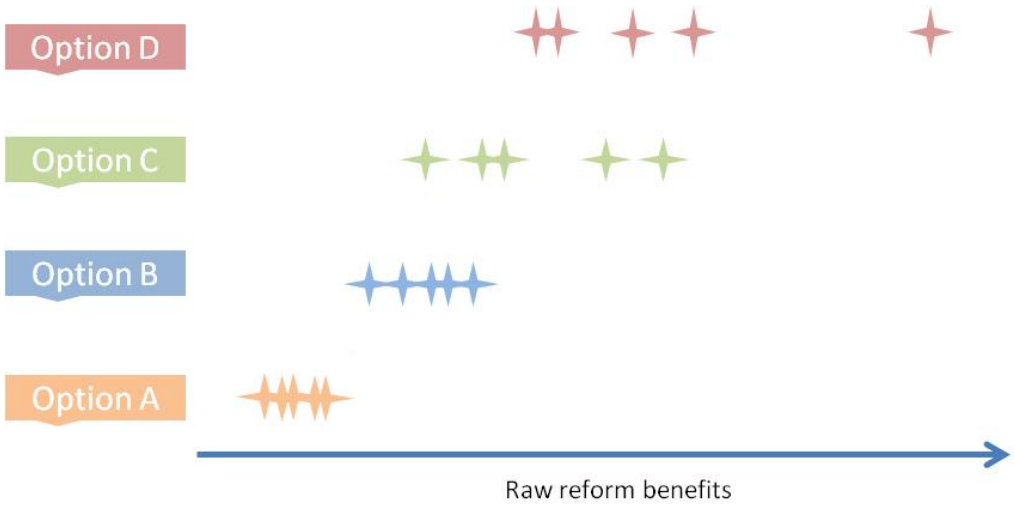


Source: Electricity Authority

10.11 Whether this possibility is important will be assessed through the course of the benefits analysis, and in particular the case study and scenario development proposed.

10.12 Stylised “raw” results for the proposed benefits analysis approach are set out in Figure 8 below.

Figure 8 Idealised interim benefits results



Source: Electricity Authority

10.13 Figure 8 highlights that some options may deliver higher levels of benefits but with wider or narrower benefits estimate distributions. In this stylised example, Option A is assumed to be a low benefits option but with a narrow distribution in benefits estimates. Option D is assumed to have higher benefits but a wider distribution of benefits estimates, possibly reflecting downward adjustments associated with detriments. As noted in the previous section, the initial benefits estimates may need to be revised downward, to take into account realistic or likely detriments from a given reform option or reform aspect.

10.14 An economic CBA is forward looking. As discussed in paragraph 9.1, benefits are assumed not to begin until sometime after the start date. They are assumed to grow only gradually, and in a growth scenario the efficiency factor represents a slower increase compared with the revenue base in the baseline forecast.

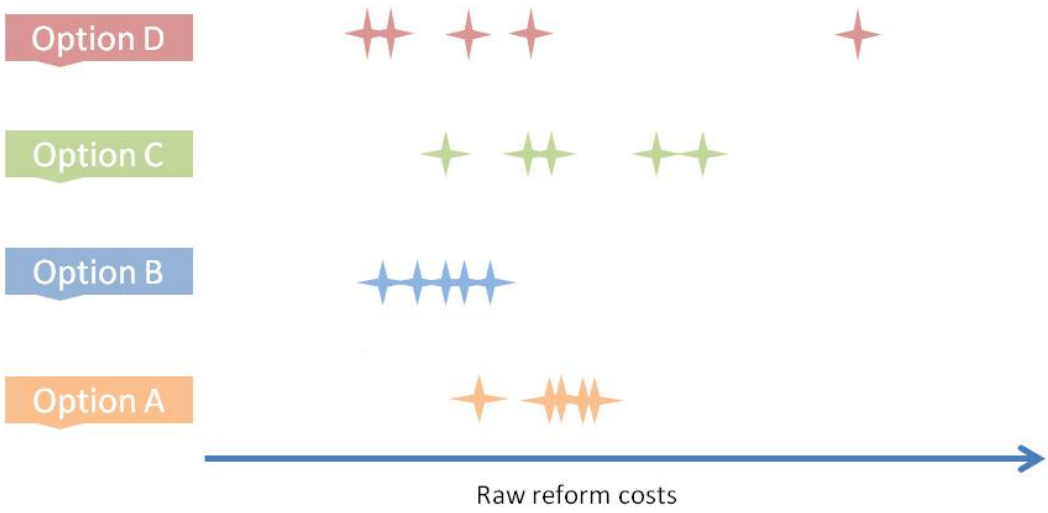
10.15 Any stranding of non-transmission sunk costs attributable to a TPM proposal would be addressed in the context of stakeholder impacts. Consistent with relevant guidance on best practice CBA, it would be excluded from the quantification of benefits and costs.

10.16 The approach to estimating implementation and on-going costs of pricing reform will be modified. The aim is to draw on new evidence as to implementation costs provided in the course of submissions and cross submissions. Additional benchmark data on the costs of similar reforms will also be sought.

10.17 Similar to the approach to measuring benefits, a distribution of costs will be developed in order to provide a sound base for selecting an overall cost estimate. This approach is set out in more detail below.

10.18 Stylised “raw” results for the proposed costs analysis approach are set out in Figure 9 below.

Figure 9 Idealised interim cost results



Source: Electricity Authority

10.19 Figure 9 highlights that some options may deliver higher levels of costs but with wider or narrower benefits estimate distributions. In this stylised example, Option A is assumed to be a low cost option with a narrow distribution in benefits estimates. Option D is assumed to have higher costs and a wider distribution of cost estimates.

10.20 An explicit process of reconciling the distribution of benefits (and cost) estimates would be undertaken. Among other things, this would refer to the underlying causal model and any normalisation process undertaken in the extrapolation from benchmark data in order to arrive at a considered view as to point in the spectrum that provides the best estimate. This is considered a more sound approach than simply adopting an average of the data points.

10.21 The reconciliation process would be applied in the first instance to the raw estimates. It is, however, also possible that a reconciliation process could also be applied to PV estimates. An example would be where the estimated benefits (or costs) of two options were similar, while the benefits (and costs) profiles were materially different.

11 Adjust for differences in the timing of the impacts

11.1 It is proposed that a range of values would be calculated for different appraisal periods. The estimated breakeven duration for each reform option would be specified as part of the moderation step. Indicatively, a 20 year appraisal period may be used for presenting summary CBA results, alongside values of 10 and 30 year periods. This means that, if the start date is January 2016, the proposed terminal date for summary reporting purposes would be the end of December 2035.

11.2 A discount rate of 6±2% was used in the 2012 CBA. It was noted in the CBA that this is the mid-point vanilla real weighted average cost of capital (WACC) as determined by the Commerce Commission for application to Transpower in the 2013 year.

11.3 After considering submissions on the matter and reviewing its approach to cost-benefit analysis more broadly, the Authority is proposing to use a different discount rate. The discount rate will be used in the context of decisions about the allocation of transmission costs across a range of parties, which is a policy decision.

11.4 The Authority therefore proposes to use a discount rate that is appropriate to evaluating policy proposals, rather than use a discount rate based on Transpower's WACC, which has been set in order to promote efficient commercial decisions by Transpower itself. Further, the long-term risk free rate is 6%, so the lower bound of the range used in the October 2012 consultation paper is too low. The Treasury advises using 8% as a default rate where no other rate is available.[25] Given this, the Authority has decided to use the discount rate advised by Treasury, which at present is 8%. This rate would be tested with sensitivity analysis by varying it by ±2%.

11.5 Conversion of costs and benefits to present values is of course necessary to normalise the differences between TPM options in terms of costs and benefit profiles. The likely effect of this process is to improve the ranking of options with lower transition costs, other things being equal.

11.6 It is proposed to convert efficiency benefits results to:

(a) nominal unit prices (not discounted)

(b) aggregate discounted values

11.7 A change in nominal unit prices may be compared with bottom up estimates. Aggregate discounted values may be compared with the present value of deferred or avoided operating or investment costs derived from bottom up case studies.

[25] http://www.treasury.govt.nz/publications/guidance/planning/costbenefitanalysis

12 Calculate decision criteria

12.1 This step consists of ranking the options. Importantly, the quantitative ranking could be subject to revision as a result of taking into account risk and uncertainty including intangibles. For example if an Option C appears to have a higher estimated present value compared with an Option D, but Option D offers significantly lower risk, uncertainty and significant additional intangible benefits, then Option D could be selected over Option C.

12.2 In accordance with guidance for an economic CBA, the objective is to seek to identify an option that maximises social or economic welfare consistent with promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long term benefit of consumers. This contrasts with a financial CBA where the objective may be to identify an option that offers the highest risk adjusted return on investment. What this means in practice is that an option with a modest benefit to cost ratio may be preferred over an option with a higher benefit to cost ratio - consistent with the Code Amendment Principles the Authority's decision rule is highest net benefits.

13 Analyse the sensitivity of the results

13.1 As noted earlier, depending on the ranking of options based on net present benefits (or costs), it may be necessary to revisit the moderation step for the purpose of assessing risk and uncertainty.

13.2 This step would include undertaking a sensitivity analysis under alternative assumptions and under alternative estimates of costs and benefits. This would include realistic assessments of pessimistic and optimistic estimates of costs and benefits. Pessimistic estimates are based on higher costs, lower benefits and other adverse assumptions.

13.3 The primary objective would be to test the robustness of any finding that, even under a realistic pessimistic case, benefits would nevertheless exceed costs. In other words, the assessment involves considering whether benefits would exceed the hurdle level of benefits necessary to move to a significantly positive benefit to cost ratio. "Significant" is likely to be expressed both as a percentage of estimated reform costs and as a nominal dollar amount, such as a $10m net benefit.

13.4 The sensitivity applied in the 2012 CBA was based on the percentage benefits in the order of plus or minus 30 per cent. The proposed approach for a 2013 CBA is to draw a more empirically robust pessimistic scenario, based on the range of efficiency estimates developed in the course of the benefits quantification. Similarly, the pessimistic scenario would also draw on the range of cost estimates identified.

13.5 In considering risk and uncertainty, it is important to consider the possibility the probability distribution of outcomes does not correspond to a normal, bell shaped curve. In particular, it is important to take into account so called ‘long tail’ risks. These risks relate to low probability but high impact outcomes.

13.6 A further proposed enhancement is to consider how pessimistic scenarios might evolve. This could include consideration of a scenario where the transition period is extended, resulting in higher costs, but also a deferral in benefits.

13.7 This step would explicitly consider intangible costs and benefits. It is possible that some difficult to quantify detriments could be considered here. It is also possible that some difficult to quantify benefits could also be considered here. To the extent durability benefits are upheld but considered to be problematic to quantify, they could be considered here.

13.8 Some aspects of stakeholder impacts (see section 14 below) may be relevant to the risk assessment. An example might be the likelihood of higher costs or lower benefits.

14 Assessing stakeholder impacts

14.1 While not part of the CBA, the Authority intends to include an assessment of stakeholder impacts in the second issues paper, as it did in the October 2012 issues paper. The stakeholder impacts discussion from the 2012 issues paper will be reviewed, modified and extended as required. The stakeholder impacts section would draw on Authority modelling on the impacts of TPM reform.

14.2 This section could include or draw on the proposed case studies outlined earlier, and this section would seek to identify cases in which certain types of assets could be stranded or partly stranded if a particular TPM option was implemented. As noted earlier, losses from asset stranding would represent financial costs to market participants, but not economic costs that need to be accounted for in the CBA.

14.3 Stakeholder impacts will be taken into account in the benefits and costs quantification to the extent they have adverse or positive economic impacts.