scientia consulting
energy modelling

Technical evaluation of AoB approach used in the TPM second issues paper

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Date: July 2016

About us

scientiaconsulting provides specialist modelling and analytical expertise to the energy sector.

This knowledge is based on extensive practical experience spanning operational and regulatory environments of the electricity industry in New Zealand and overseas.

Scientia's key areas of specialisation include electricity market design, analysis, market clearing engine development and testing, transmission pricing, transmission planning, load forecasting and generation expansion modelling.

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Executive Summary

The Electricity Authority (Authority) has proposed the use of an Area-of-Benefit (AoB) charge for allocating the costs of some existing and future transmission investments. The Authority is clear in its proposal that the AoB approach will be developed by Transpower (following the guidelines developed by the Authority) however it has exemplified an option for such determination using a forecast SPD method to provide illustrative AoB charges in its consultation paper.

Transpower has engaged Scientia Consulting to undertake a technical evaluation of the AoB approach used by the Authority in its 2nd issues paper. In particular Transpower would like to better understand:

- Details of how the AoB charge has been modelled by the Authority
- Highlight any potential issues if Transpower were to use such an approach to develop charges for:
    - Existing investments
    - Future investments

A summary of our findings are discussed below.

How was the AoB charge modelled

The Authority's AoB charge can be separated into two steps. An identification step that determines for each eligible investment, the beneficiaries over the life of the investment[1] and an allocation step wherein the cost of the eligible investment is allocated to the identified beneficiaries.[2]

In its illustration of the AoB charge, the Authority used the forecast SPD method to determine an estimate of future private benefits which were used in both the identification and allocation steps above with two notable observations:

- The modelled AoB approach was not applied to the entire list of eligible investments provided by the Authority (shown in the Appendix) but limited to the larger cost investments as shown in Table 1. Where the forecast SPD method was not used an allocation of the costs to a set of pre-specified beneficiaries was used[3]. The pre-specified allocation was also used where the benefits assessed using the forecast SPD method was lower than the revenue requirement of the investment (as was the case with the NAaN investment).

[1] See Appendix for description of the Authority's eligible investments.

[2] The Authority prefers an allocation based on calculated benefits where practicable. As an alternative, the Authority proposes allocating to loads and generators based on gross AMD and energy (MWh) respectively (as proposed for the residual).

[3] We understand from the Authority's response to questions that this pre-specified allocation is based on 'engineering inspection' (and in discussion with Transpower) of the benefits arising from these investments.

- The AoB approach described in the Authority's consultation paper indicates the estimation of benefits over the life of the asset[4] whereas the modelled approach was for a single modelled future year (2019).

Using its vSPD model with adjusted historic inputs to simulate a future year (2019), the Authority calculated an estimate of future private benefits for each load and generator node connected to the transmission grid. This was calculated using a two-solve process for eligible investments; one with the investment in service, and one without the investment in service. Using the solved nodal prices and cleared generation and load quantities, a half-hourly private benefit (consumer surplus for loads and producer surplus for generators) was calculated for each load and generator node under the two solve scenarios ('with' and 'without') for the modelled year. The half-hourly *net* private benefit (or dis-benefit) was then determined as the difference between the calculated private benefits with the investments less the calculated private benefit without the investment. Loads and generators were identified as beneficiaries if their total net benefit (sum of benefits and dis-benefits) over the year was positive.

In the allocation step, the assessed investment's cost was allocated to the identified beneficiaries of that investment in proportion to their calculated positive net benefits (from the identification step) up to the investment cost.

In the Authority's nodal assessment, distributors are regarded as proxies for its customers and any benefit calculated for a distributor's customers was assigned to that distributor.

Identified issues with the modelled AoB approach

Calculated benefits are highly sensitive to choice of modelling assumptions

The AoB approach outlined by the Authority requires an ex-ante estimation of private benefits for each load and generator on the power system for the life of each eligible investment which for some assets would be greater than 20 years into the future.

This would require Transpower create a forecast of nodal prices, cleared generation and load quantities several decades into the future and use these forecasts as the basis for estimating private benefits and allocating eligible transmission asset costs based on these benefit estimates.

Such an approach would be very sensitive to modelling inputs and assumptions as nodal prices, cleared generation and load quantities at different nodes would vary (sometimes quite drastically) depending on the modelling assumptions used to model the power system, its dispatch and evolution over the next two to three decades. Changes to the input assumptions could translate into potentially large variations in assessed benefits for participants and consequently potentially large variations in allocated transmission costs depending on the choice of assumptions.

[4] This could be more than 20 years for transmission investments.

To provide an illustration of how sensitive such an assessment could be to modelling assumptions, we consider how the assessed benefits[5] might have changed for the NIGU investment had the same benefit assessment been undertaken at the beginning of 2015 rather than 2016[6], in effect the sensitivity of the assessed benefits to changes in modelled system conditions which occurred over an approximately one year period. With this variation to the modelling inputs, we re-calculated the nodal prices, and cleared quantities. The revised assumptions indicate a significant reduction in the assessed benefit calculated at the largest upper North Island (UNI) beneficiary in the week in which it received its largest net benefit ($4.4m to $0.1m - a 97% reduction).

We consider that such extreme variations in the assessed benefits at nodes could be expected to occur if Transpower used the modelled AoB approach as assumptions about the entry and exit of generators and loads, their offers and bids, transmission network and security constraints over a twenty year modelling horizon could significantly affect the calculated nodal prices, cleared nodal generation and load and consequentially the calculated benefits and cost allocation of each node. We consider this volatility would reduce Transpower's ability to justify the credibility of the calculated nodal benefits (and cost allocation) as the modelled AoB approach based on these nodal benefits is intrinsically dependent on the choice of modelling assumptions.

Ignoring dependency of investments can distort benefit assessments

The Authority's assessment of the counterfactual state of historic investments (i.e. without the investment) is a near-identical system state but with the assessed investment removed from service. This makes a significant assumption that transmission, generation and load investment and retirement decisions are independent of one another.

We consider that this independence is not a plausible case and can result in counterfactual states of the power system for which it was never designed which could distort cleared generation, cleared load, power flows, binding constraints and nodal prices, affecting the assessed benefits (under the proposed benefit calculation approach) and consequentially distorting the resulting cost allocations.

As an example, in the Authority's benefit assessment of the NIGU investment, it assumes the counterfactual state with 'no NIGU' as a system where all subsequent transmission investment and generation retirement decisions remain unaffected with the removal of the NIGU investment.

To illustrate the potential distortionary effect of ignoring the path dependency of power system investment and retirement decisions in this benefit assessment approach, we simulate an alternate counterfactual of the 'no NIGU' scenario but without the post-NIGU transmission investment and retirement decisions which were

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[5] Using the modelled AoB approach.

[6] This assessment is for the same modelled future year used by the Authority (2019).

included in the Authority's modelling. Under this alternate counterfactual, we observe no positive net benefit calculated for the largest UNI load "beneficiary" of NIGU when compared to the Authority's assessment in which the path-dependence of power system development is ignored.

Creating a counterfactual for the benefit assessment of historic investments that would be more akin with the assessment of future investments, would require an additional set of assumptions of how the power system may have evolved had the historic investment not occurred. As outlined in the previous section, these assumptions can (potentially significantly) affect the calculated nodal benefits given the sensitivity of the modelled benefit approach to nodal price and cleared quantity forecasts undermining the credibility of the resulting charges.

Conclusion

Based on our assessment, we consider that very significant design and implementation issues exist with the modelled AoB approach which we believe affects its ability to be used as a practicable, stable and credible process for Transpower to allocate transmission costs to its customers.

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1. Introduction

The AoB method is one of the main component charges proposed by the Authority in its second TPM issues paper.

While the Authority has made it clear that Transpower would be responsible for developing the AoB approach, it outlined several alternative approaches to model the AoB charge. One of these was the forecast SPD method which the Authority used in its consultation paper to illustrate the application of the AoB charge.

This report describes our assessment of the forecast SPD approach used by the Authority in its consultation paper.

2. Understanding the modelled AoB charge

2.1. Overview of the approach

The Authority's proposed AoB charge can be separated into two steps:

- Step 1: Identifying the beneficiaries of each eligible investment[7]
- Step 2: Allocating the cost of the eligible investment to the beneficiaries identified in step 1. The allocation in step 2 is in proportion to the benefits calculated in step 1.[8]

The forecast SPD method was used to identify the beneficiaries for each eligible investment in step 1 by calculating changes in consumer and producer surplus at load and generator nodes respectively. This private benefit estimate involved the following approach.

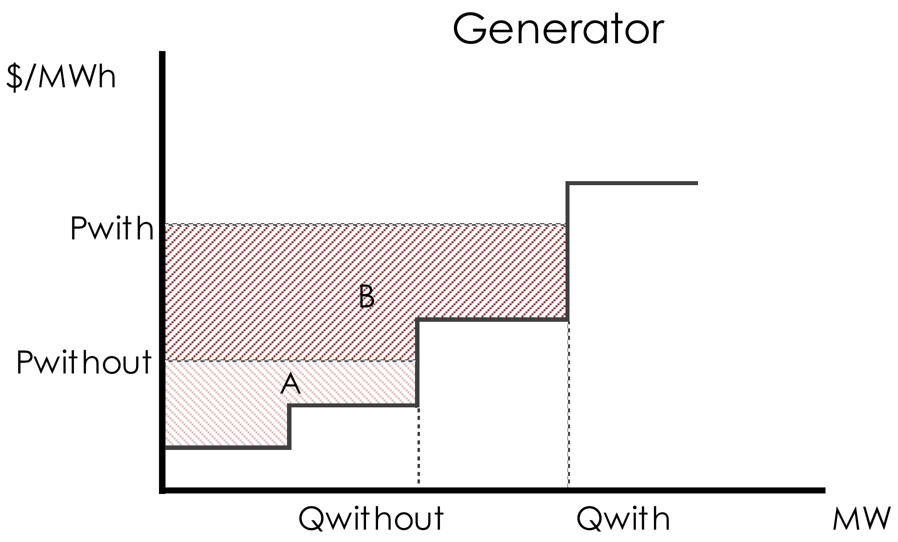
The SPD method is used to <u>forecast</u> wholesale market prices as well as cleared load and generation quantities at each node on the network for every half-hour interval for the life of the assessed investment.[9] This forecast is undertaken for two scenarios; one <u>with</u> the investment in service and another scenario <u>without</u> the investment in service.

An estimate of consumer and producer surplus is calculated using the calculated nodal price, load and generation forecasts in each scenario. The change in consumer and producer surplus at each node is calculated as the surplus with the investment in place less the surplus without the investment. A positive change in surplus is considered a benefit and a negative change a dis-benefit from that investment. An illustration of this private benefit assessment is shown in Figure 1.

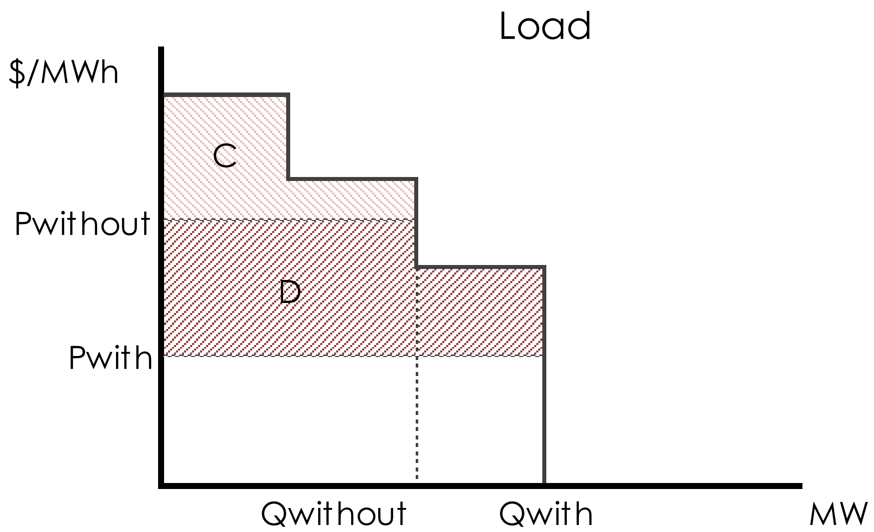
[7] See Appendix for description of the Authority's eligible investments.
[8] The Authority prefers an allocation based on calculated benefits where practicable. As an alternative, the Authority proposes allocating to loads and generators based on gross AMD and energy (MWh) respectively (as proposed for the residual).
[9] This could be greater than 20 years for some transmission assets.

Figure 1: Illustration of generator and load private benefit calculation

The generator private benefit (net producer surplus) = (A+B)-A = B



The load private benefit (net consumer surplus) = (C+D)-C = D



The final step in the identification process involves the aggregation of the calculated half-hour private benefits for each load and generator over the life of the asset. A beneficiary is a load or generator whose total net benefit (sum of benefits and dis-benefits) over the lifetime of the asset was positive.

The second phase of the AoB approach is the allocation of the assets costs to identified beneficiaries. In the modelled approach the benefits used in the identification phase (step 1) were used to allocate the costs of the investment to identified beneficiaries of that investment. This allocation was done in proportion to the participants calculated positive net benefits (from step 1), up to the cost of the investment.

In the modelled approach, all assessed benefits at load nodes assigned to a distributor are allocated to the distributor as the distributor is regarded as a proxy for its customers.

All identified beneficiaries are allocated costs of eligible investments greater than $5m. A simplified AoB approach is proposed by the Authority for eligible investments less than $5m where only the largest beneficiaries would be allocated the costs under step 2. This simplified approach is proposed to reduce transaction costs of a more granular approach.

2.2. Details of the modelled approach

In its consultation paper, the Authority used its vSPD model to provide an illustration of the forecast SPD method. While the AoB approach outlined by the Authority requires the estimation of private benefits over the life of the asset, the illustrative approach and calculated charges are based on simulation for a single future year, representing 2019.

A number of modifications were made to historical data files to simulate a future year as outlined in the Authority's paper. These involved adjustment to demand, some generator offers, demand bids and the transmission network. The network adjustments involved creating alternate 'with' and 'without' network scenarios to perform the corresponding 'with' and 'without' benefit assessment as outlined above.

A list of the historic investments indicated by the Authority as being eligible for allocation under the AoB method is shown in the table below. The forecast SPD method (referred to as simulation method in the table) was only used for the larger cost investments assessed by the Authority with a pre-specified allocation used for others[10].

For each assessed investment, the 'with' and 'without' simulations yielded nodal prices, cleared generation and cleared load for each half-hour trading period of the simulation year. The nodal prices and cleared quantities were used to determine nodal estimates of private benefit identify beneficiaries and allocate the revenue requirement of the asset based on the approach outlined in the previous section.

[10] We have not considered the approach used by the Authority and understand from the Authority's response to questions that this pre-specified allocation is based on 'engineering assessment' (and in discussion with Transpower) of the benefits arising from these investments.

Table 1: Modelling details of historic eligible assets specified by the Authority

Investment	Rev Req ($m)	Approach	Identified beneficiaries	Allocation to identified beneficiaries
NIGU	85.3	Simulation method	Based on simulation	Simulated private benefits
Pole 3	72.9		Based on simulation	Simulated private benefits
Pole 2	45.1		Based on simulation	Simulated private benefits
NAaN	39.2		Based on simulation	Simulated private benefits **+ pre-defined**
LSI Renewables	4.2		Based on simulation	Simulated private benefits
Wairakei Ring	14.8		Based on simulation	Simulated private benefits
Otahuhu GIS	12.0	Specified allocation	Load north of BOB	Pre-defined allocation
BPE-HAY re-conductoring	5.5		NI gen (50%) SI gen (50%)	Pre-defined allocation
USI reactive support	3.5		SI loads (Cch and north)	Pre-defined allocation
UNI dynamic reactive support	5.5		Load at and north of BOB	Pre-defined allocation
LSI Reliability	2.1		LSI loads	Pre-defined allocation

3. Issues identified with the modelled approach

3.1. Calculated benefits are highly sensitive to choice of modelling assumptions

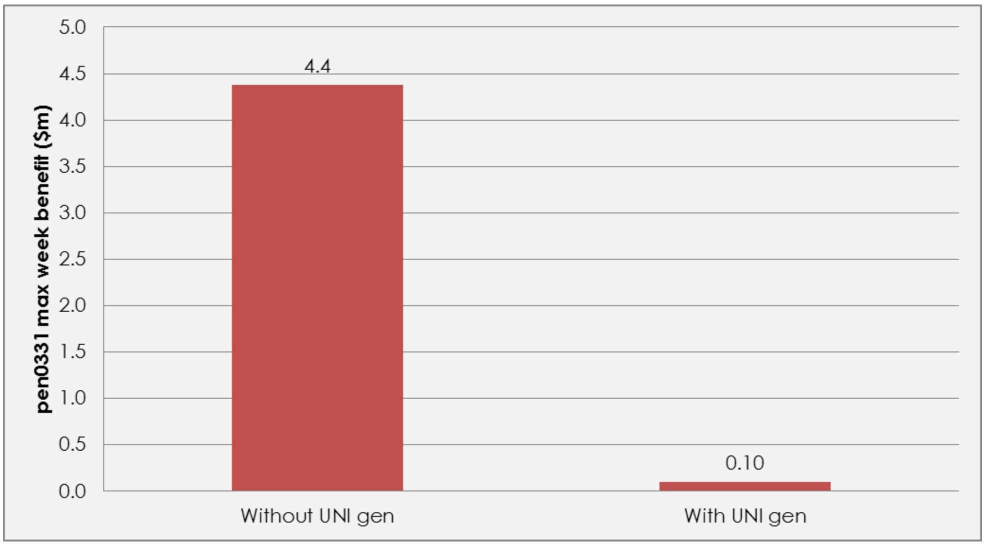
The AoB approach outlined by the Authority requires an ex-ante estimation of benefits for each load and generator on the power system for the life of each eligible investment which for some assets would be greater than 20 years into the future. If the consumer and producer surplus metric for beneficiary identification is used (as modelled), this would require Transpower to provide a forecast of nodal prices, cleared generation and load quantities several decades into the future. These forecasts become the basis for calculating the benefits each generator and load is expected to receive from the asset and consequentially allocate the costs of these assets based on these benefit estimates.

We consider such an approach would be very sensitive to modelling inputs and assumptions as nodal prices, cleared generation and load quantities at different nodes would vary (sometimes quite drastically) based on modelling assumptions and how the power system may evolve over the next decades. Changes in these nodal prices and cleared quantities imply changes in assessed benefits for loads and generators, if using the modelled approach and consequently changes in allocated transmission costs to different parties.

To provide an illustration of how sensitive such an assessment could be to modelling assumptions, we consider how the assessed benefits[11] could have changed for the NIGU investment had the same benefit assessment been undertaken at the beginning of 2015 rather than 2016[12]. In effect, we are considering how sensitive the assessed benefits are to changes in modelled system conditions which occurred over an approximately 1 year period.

At the beginning of 2015, there was little/no knowledge in the market of the decisions to retire the UNI thermal generators at Southdown and Otahuhu.[13] We repeated the Authority's benefit calculation with the inclusion of both these UNI generators and compared the calculated benefits for the largest UNI load beneficiary over a selected week[14]. Figure 2 below shows the large reduction in the calculated benefits over week (from $4.4m to $0.1m) at this node (Penrose 33kV) under the alternate modelling with the UNI generation illustrating how sensitive the assessed benefits are to assumptions of future system states.

Figure 2: Calculated benefit for Penrose 33kV (PEN0331) node (maximum week) with and without UNI generation



We consider that such large variations in the assessed benefits at nodes could be expected to occur if Transpower used the modelled AoB approach as assumptions about existing and future generators and loads, their offers and bids, transmission network and constraints used to facilitate modelling of the power system over a twenty year horizon could significantly affect the calculated nodal prices, cleared nodal generation and load and consequentially the calculated benefits and cost allocation of each node. This strong dependency of the private benefit assessment

[11] Using the modelled AoB approach.

[12] This assessment is for the same modelled future year used by the Authority (2019).

[13] As evidenced by the inclusion of both these generators in the Annual Security of Supply assessment undertaken by the System Operator in the beginning of 2015. Generators provide inputs into this process on generation capability.

[14] We selected the week in which the original benefit assessment calculated the highest net benefit for the PEN0331 UNI node.

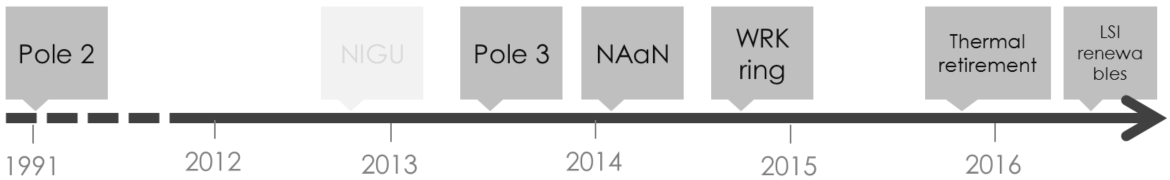
to the selected modelling assumptions would affect Transpower's ability to justify the credibility of the cost allocation.

3.2. Ignoring dependency of investments can distort benefit assessments

The Authority has classified some historic investments as "eligible" and used the same modelling approach for these historic investments as it would for future investments under the AoB approach. This modelled approach assesses the counterfactual state (i.e. had a historic investment not occurred) as a near-identical system state but with the assessed investment removed from service. In applying such an approach to historic investments, the modelled AoB approach makes the significant assumption that transmission, generation and load investment and retirement decisions are independent of one another. This independence is not a plausible case and can result in counterfactual states of the power system for which it was never designed. The effect of an implausible counterfactual is to potentially distort cleared generation, load, power flows, binding constraints and nodal prices, all of which can affect the assessed benefits (under the proposed benefit calculation approach).

Figure 3 below provides an illustration of the alternate power system configuration used by the Authority to assess the benefits of the NIGU investment under the modelled AoB approach. Here we see that the counterfactual state 'no NIGU' assumes that all the subsequent transmission investment and generation retirement decisions proceed unaffected with the non-existence of the NIGU investment.

Figure 3: Modelled investments and retirements assumed for the 'no NIGU' counterfactual

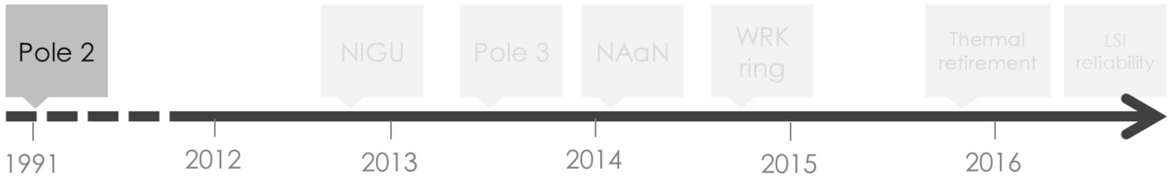


To illustrate the potential impact of ignoring the dependency of power system investment and retirement decisions in this benefit assessment approach, we simulated an alternate counterfactual of the 'no NIGU' scenario but without the post-NIGU transmission investment and retirement decisions. This is shown in

Figure 4.[15]

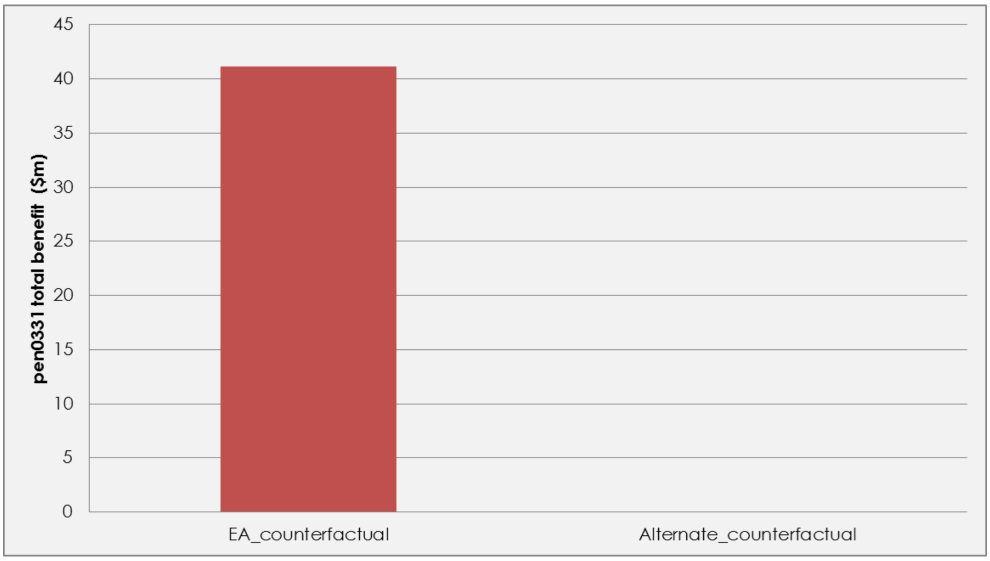
[15] The assessment was also undertaken for the same simulated future year as in the Authority's analysis (2019).

Figure 4: Alternate modelled investments and retirements assumed without the NIGU investment



In this assessment of NIGU benefits under an alternate counterfactual, a significantly lower benefit is calculated for UNI load participants, as illustrated by the elimination of the calculated aggregate positive net benefit at the largest UNI load beneficiary node[16] shown in Figure 5.

Figure 5: Comparison of calculated benefit for Penrose 33kV (PEN0331) node under alternate counterfactuals



We consider that this is illustrative of the potential distortions that could be introduced into the benefit assessment of historic investments if the dependence of system states is ignored.

Creating a counterfactual for the benefit assessment of historic investments that would be more comparable with the assessment of future investments, would require an additional set of assumptions of how the power system may have evolved had the historic investment not occurred. But as outlined earlier, the choice of assumptions can (potentially significantly) affect the calculated nodal benefits given the sensitivity of the private benefit approach to nodal price and cleared

[16] As assessed by the Authority's NIGU analysis.

quantity forecasts. This in turn would affect the robustness and credibility of the transmission cost allocation determined by Transpower.

Appendix

The following are the eligible investments described by the Authority in its consultation paper.

A project or programme of base capex or major capex that is commissioned on or after the date of the guidelines

The costs of any payments by Transpower in respect of a non-transmission solution

The following investments:

- North Island Grid Upgrade (NIGU) Project
- Upper South Island Dynamic Reactive Support Project
- Otahuhu Substation Diversity Project
- HVDC (Pole 3) Project
- Wairakei Ring Project
- North Auckland and Northland (NAaN) Project
- Upper North Island Dynamic Reactive Support Project
- Lower South Island Renewables Project [CUWLP]
- Lower South Island Reliability Project
- Bunnythorpe-Haywards Re-conductoring Project
- Pole 2 of the HVDC link