TRANSPOWER

TPM INFORMATION SHEET

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Benefit-based charges: Standard methods

This Information Sheet describes the standard methods for calculating starting allocations for benefit-based investments (BBIs) under the transmission pricing methodology (TPM).

The standard methods are used for post-2019 high value BBIs (BBIs valued at over $30m).

The starting allocations for a BBI are used to calculate each customer's benefit-based charges (BBCs).

This Information Sheet provides an overview of:

- the different types of BBI
- which BBIs the standard methods apply to
- how the standard methods work.

Separate Information Sheets on other aspects of BBCs have been published:

- the BBC simple method
- the Appendix A BBIs
- BBC adjustment events
- a BBI's covered cost.

The requirements for the standard methods, and calculating BBCs generally, are in Part D of the TPM.

All clause references in this Information Sheet are to clauses of the TPM.

Legal disclaimer

This Information Sheet provides a high-level overview of the relevant subject matter only.

Transpower recommends you review the TPM itself and seek independent expert advice before relying on anything in this Information Sheet.

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Version history for this guide

Version	Published	Key amendments compared to previous version
1	29 September 2022	n/a
2	28 May 2025	Update to introductory text about other information sheets, change in base capex threshold, correction to typos and minor editorial changes
3	11 August 2025	Update to include a more detailed explanation of how we determine regional customer groups for BBIs with market benefits, how we treat embedded generation, and how allocations might change over time

1 What are benefit-based investments?

Benefit-based investments (BBIs) are investments in interconnection assets and interconnection transmission alternatives (interconnection investments). They typically include investments in the replacement and refurbishment of existing interconnection assets and transmission alternatives that avoid or defer the need to invest in interconnection assets.

There are two types of BBI:

- Appendix A BBIs (also referred to as 'historic BBIs'). These are seven pre-July 2019 interconnection investments for which the Authority calculated the starting BBI customer allocations and specified these in Appendix A of the TPM.
- Post-2019 BBIs. These are interconnection investments commissioned after 23 July 2019. Starting BBI customer allocations for post-2019 BBIs are calculated by Transpower using a standard method or the simple method in the TPM.

Post-2019 BBIs can be high value or low value. The standard methods for calculating starting allocations for high-value post-2019 BBIs are the subject of this Information Sheet.

A group of interconnection investments may comprise one or more BBIs.[1] A BBI may include several related projects, or one project may be split across two or more BBIs.

The BBC Assumptions Book (assumptions book) contains more detail about how we define BBIs and about how the standard methods work generally.[2]

2 What are benefit-based charges?

Benefit-based charges (BBCs) recover the costs of a BBI, from customers identified as expected beneficiaries of the BBI.

A customer is expected to be a beneficiary of a BBI if it has expected positive net private benefit (EPNPB) from the BBI. A customer's starting allocation for the BBI is the customer's share of total EPNPB.

The cost recovered through the BBCs for a BBI is referred to as the BBI's "covered cost". A BBI's covered cost includes capital components (return on and of investment) and an allocation of Transpower's total operating costs (including overheads). The covered cost is calculated annually, for each BBI.

1 See section 3.2 of the [Assumptions Book | Transpower](#).
2 See sections 3.1 – 3.4 of the [Assumptions Book | Transpower](#).

Each customer's starting allocation for a BBI is calculated to be broadly in proportion to the EPNPB the customer is expected to derive from the BBI, as expected at an early point in its lifecycle (in most cases, some point before the investment decision is made). That is, the BBC paid by a customer reflects the positive NPB that customer is expected to receive from the BBI (if any), relative to all other customers.

A customer's BBC for a BBI is the BBI's covered cost multiplied by the customer's allocation for the BBI.

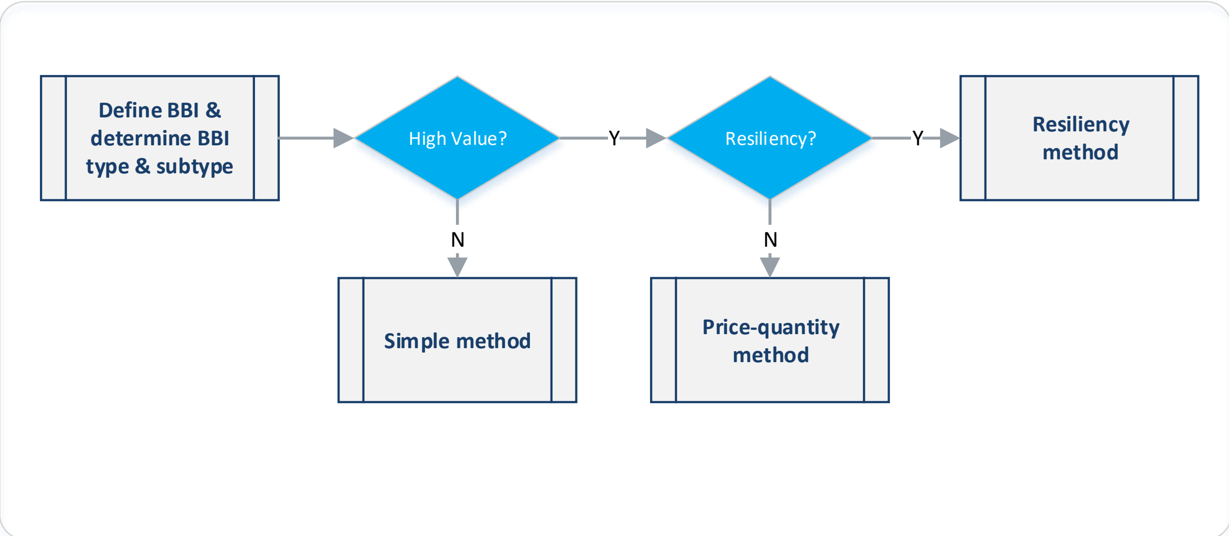
Each customer's allocation for a BBI is fixed over the life of the BBI, unless a change to the allocation is triggered by one of the adjustment events in Part F of the TPM.

3 When do the standard methods apply?

The TPM includes three methods for calculating EPNPB, and therefore starting allocations, for post-2019 BBIs. There are two standard methods (the resiliency and price-quantity methods) and one simple method.

The two standard methods are used to calculate EPNPB and starting allocations for post-2019 BBIs that, at the time of the investment decision, are expected to cost over $30m (high-value post-2019 BBI).[3]

The simple method is used to calculate EPNPB and starting allocations for post-2019 BBIs that, at the time of the investment decision, are expected to cost $30m or under (low-value post-2019 BBIs).



[3] The high-value/low-value test in the TPM increased from $20m to $30m on 1 April 2025.

An example of an investment where a standard method applies (the price-quantity method) is the Clutha and Upper Waitaki Lines Project (CUWLP).[4]

4 What are the standard methods and how do they work?

There are two standard methods: the price-quantity method and the resiliency method.

The resiliency method must be used where the primary purpose of the high-value post-2019 BBI is to mitigate a risk of cascade failure or another high impact, low probability (HILP) event resulting in unserved or unsupplied energy (referred to as a resiliency BBI).

The price-quantity method must be used for all high-value post-2019 BBIs that are not resiliency BBIs. The price-quantity method calculates EPNPB based on price and quantity changes (with and without the BBI) in the wholesale markets for electricity and ancillary services and changes in reliability (unserved or unsupplied energy). Subject to certain limits, under the price-quantity method Transpower may also take into account other costs and benefits that arise outside electricity markets, such as aesthetic or safety improvements.

The standard methods are applied separately to each high-value post-2019 BBI. This means, unlike under the simple method, regions, regional customer groups, and regional and individual NPB are variable between BBIs under the standard methods.

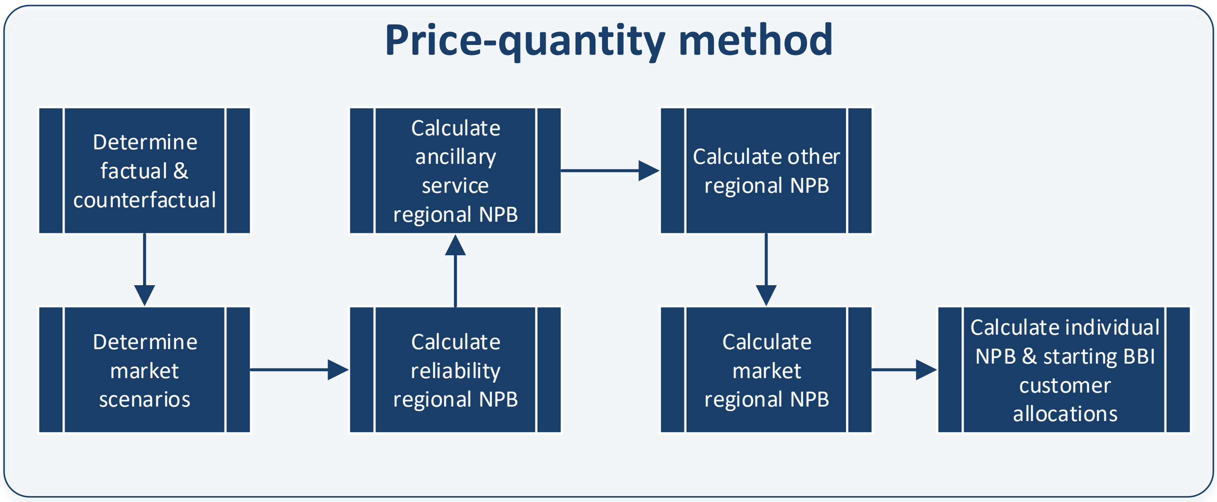
Most high-value post-2019 BBIs will be tested investments (investments to which an investment test under Transpower's Capex IM[5] has been applied). The assumptions and other inputs we use to apply a standard method must be as consistent as reasonably practicable with those used for the investment test. We may use different inputs if we determine alignment with the investment test will not result in starting allocations that are broadly proportionate to EPNPB, but must not use an input that contradicts a key driver of the investment decision for the relevant BBI (clause 43(5)). When a standard method requires an input that did not have an equivalent in the investment test, or we decide to depart from the investment test input, we will typically use the relevant input in the assumptions book (if there is one).

4 TPM Determination: CUWLP starting BBI customer allocations: Decision Paper, 15 September 2022.

5 Transpower Capital Expenditure Input Methodology Determination 2012. The investment test assesses changes in electricity market costs and benefits (efficiency) whereas the standard methods assess changes in private costs and benefits, which include wealth transfers between parties within the electricity market.

5 The price-quantity method

The price-quantity method involves the following steps, which are summarised below.



More detail about the price-quantity method is in section 3.3 of the assumptions book.

5.1 Determine the factual and counterfactual

Transpower must determine the factual and counterfactual (the future state of the grid with and without the BBI). The counterfactual depends on the BBI's investment type, which could be compliance, replacement, refurbishment, enhancement or a combination of those types. Clause 45(2) contains the rules for determining the counterfactual, which we may depart from if we determine applying the rules does not produce a reasonably likely future grid state.

5.2 Determine the market scenarios

Transpower must determine market scenarios for the BBI (clause 46).

A market scenario is a future state of factors that influence the BBI's EPNPB, such as load growth and generation expansion. Modelling under the price-quantity method is performed under each (probability-weighted) market scenario. Usually, the same market scenarios apply in the factual and counterfactual. If a market scenario includes a customer exiting, it is not applied to that customer.

5.3 Calculate regional NPB for each applicable benefit class

EPNPB is calculated under the price-quantity method using up to four benefit classes: market benefits, ancillary service benefits, reliability benefits, and other benefits. Not every BBI produces all four types of benefits. We determine which benefit classes are applicable based on the BBI's investment need. We must always calculate at least one of market, ancillary service and reliability benefits for a BBI that uses the price-quantity method.

For each applicable benefit type, we determine modelled regions and regional customer groups and calculate the present value of regional NPB for each group.

Market benefits (clauses 51 and 52)

We calculate market regional NPB when we expect the BBI to have a material impact on prices or quantities in the wholesale electricity market, relative to its counterfactual. In this case the BBI is referred to as a market BBI.

We use a market model with the following characteristics to model the price and quantity changes (TPM definition of "wholesale market model"):[6]

- generators are assumed to offer at their marginal variable cost of supply (perfect supply-side competition)
- demand is perfectly inelastic up to one or more estimated costs of self-supply
- least-cost dispatch.

The modelling is carried out on a simplified model of the grid called the investment grid. There is an investment grid for each of the factual and counterfactual. The investment grid contains:

- all existing branches and market nodes
- HVDC link constraints
- constraints on new grid assets comprised in the BBI (in the factual) and constraints materially alleviated by the BBI (modelled constraints, being pre-contingent event constraints only).[7]

From this modelling we determine the modelled regions for the BBI. To do this, we identify the grid points of connection (GXPs or GIPs) where customers are expected to experience the same or similar benefits (in proportion to their size) in terms of modelled price and quantity changes. A modelled region is a set of these GXPs or GIPs. There will typically be separate modelled regions upstream and downstream of a constraint alleviated by the BBI because, in general, a transmission constraint results in increased prices downstream of it and decreased prices upstream of it.

The offtake customers connected at the GXPs in a modelled region comprise one or more regional demand groups.[8] The injection customers connected at the GIPs in a modelled region comprise one or more regional supply groups. A modelled region may have multiple regional demand or supply groups if we expect benefits in the region to differ between load or generation types, or between existing and future load or generation. The regional demand and supply groups are the regional customer groups for which we calculate market regional NPB. Overlapping or geographically adjacent regional customer groups may later be combined if they have similar benefits in proportion to their size.

We have provided a more detailed explanation of how we determine regional customer groups for BBIs with market benefits in Appendix A.

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6 We currently use the Stochastic Dual Dynamic Programming (SDDP) modelling tool, which we also use for the investment test.

7 A pre-contingent constraint is a constraint managed by the system operator before any event occurs that disrupts the power system.

8 Excluding grid-connected batteries in some cases.

There are two methods in the TPM for calculating market regional NPB – based on changes in quantity (clause 51) and based on changes in price and quantity (clause 52). Clauses 51(1) and 52(1) contain the rules for choosing between clauses 51 and 52, and there is further guidance in the assumptions book. Broadly, clause 51 is the “default” method – we must use clause 51 where we determine most of the benefits relate to new large generating plant or where we determine the conditions for using clause 52 do not apply. We must use clause 52 where we determine most of the benefits relate to consumers avoiding high prices due to a lack of transmission and generation capacity during peak periods or where we determine clause 51 would otherwise not result in starting allocations broadly proportionate to EPNPB.

If a customer has both load and generation at the same connection location, we group them in either a regional supply or demand group for that location based on their net benefit, i.e., after offsetting generation disbenefits from load benefits (or vice versa).

Ancillary service benefits (clause 53)

We calculate ancillary service regional NPB when we expect the BBI will materially reduce the allocable cost of any of three specified ancillary services – instantaneous reserve, frequency keeping and voltage support.[9] In this case the BBI is referred to as an ancillary service BBI.

Reliability benefits (clause 54)

We calculate reliability regional NPB when we expect the BBI will materially reduce unserved or unsupplied energy (curtailed energy) in one or more outage scenarios.

We determine the customers affected by the outage scenarios for which the BBI is mitigating curtailed energy and assign those customers to either a regional demand group (for offtake customers) or regional supply group (for injection customers). Reliability regional NPB is then calculated for each group based on the group’s modelled reduction in curtailed energy (relative to the counterfactual and across the market scenarios) and the value of lost load (VoLL, as defined in the TPM) or value of lost generation (VoLG, as determined by Transpower).

Other benefits (clause 55)

Subject to the conditions in clause 55(2), we may calculate or estimate other regional NPB when we expect there will be benefits from the BBI that are not market, ancillary service or reliability benefits.

We have not developed detailed processes or methodologies for calculating ancillary service regional NPB, reliability regional NPB and other benefits at this time. We will do so when we are first required to calculate starting allocations for an ancillary service BBI.

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9 Only direct allocations of allocable cost to customers are relevant. Allocations to Transpower are ignored. This is why over frequency reserve and black start, all of the allocable cost of which goes directly to Transpower, are not included. Transpower’s allocation of the allocable cost for instantaneous reserve is also ignored.

5.4 Calculate intra-regional allocators (IRAs), individual NPB and starting allocations

The final step in the price-quantity method is to allocate the positive regional NPB for each regional customer group amongst the customers in that group, and then use those individual NPBs to calculate starting allocations for the BBI.

Calculate IRAs (clauses 65 to 67)

A regional customer group's positive regional NPB is allocated to customers in the group in proportion to the values of their intra-regional allocators (IRAs), which are measured at the points of connection to the grid, and are net by trading period.

IRA values are calculated based on customers' activity over the five complete capacity years (1 September to 31 August) immediately preceding the final investment decision date for the BBI (capacity measurement period or CMP B).

There are different IRAs depending on the regional NPB being allocated and the type of regional customer group and BBI.

Regional NPB	Regional customer group	IRA
Market regional NPB Reliability regional NPB Other regional NPB	Regional demand group	Mean coincident peak offtake (if peak BBI[10]) Mean annual offtake (if non-peak BBI)
	Regional supply group	Mean annual injection
Ancillary service NPB (IR)	Regional supply group (no regional demand group)	Mean annual injection
Ancillary service NPB (FK)	Regional demand group (no regional supply group)	Mean annual offtake
Ancillary service NPB (VS)	Regional demand group (no regional supply group)	Mean peak kVar

New customers and recent customers (customers connected for less than two full capacity years during CMP B) have their IRA values estimated (but, for recent customers, taking into account any available information about their offtake, injection or peak kVar).

10 A peak BBI is a BBI for which the investment need is primarily attributable to meeting peak demand.

Where a regional customer group consists entirely of customers who do not yet exist (referred to as a future regional customer group), we determine a notional IRA value for that group. This is necessary so that the adjustment provisions in Part F of the TPM work correctly when new customers join the group.

Calculate individual NPB and starting customer allocations (clauses 47 and 43(1))

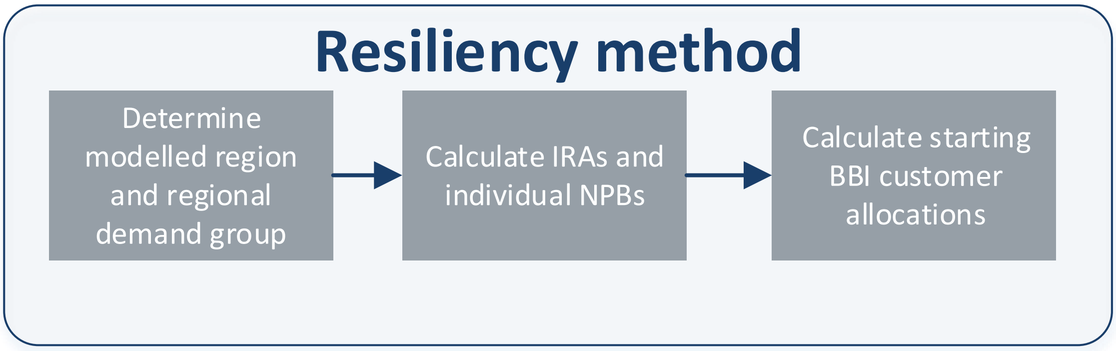
A customer's individual NPB for the BBI is the sum[11] of the product of the positive regional NPB for each regional customer group of which the customer is a member and the customer's IRA for the group as a proportion of the total of all customers' IRAs for the group.

A customer's starting allocation for the BBI is the customer's individual NPB divided by the sum of all customers' individual NPBs.

As noted above, a customer's BBC for the BBI is calculated by multiplying the BBI's covered cost by the customer's allocation (clause 35(2)).

6 The resiliency method

The resiliency method involves the following steps, which are summarised below.



More detail about the resiliency method is in section 3.4 of the assumptions book.

6.1 Determine modelled region and regional demand group (clause 58)

Conceptually, resiliency BBIs are very similar to reliability BBIs. However, for resiliency BBIs there is only one modelled region and one regional customer group.

[11] A customer may be a member of more than one regional customer group with positive regional NPB.

The modelled region is the region that would be affected by the HILP event or cascade failure risk being mitigated by the BBI. This region will be either:

- if mitigating a risk of cascade failure, the island in which the risk is mitigated; or
- the region in which the risk of the HILP event is mitigated.

The regional customer group (a regional demand group) is comprised of all offtake customers located in the modelled region, except grid-connected batteries.

6.2 Calculate IRAs and individual NPB (clauses 65, 66 and 57)

As for the price-quantity method:

- IRA values are calculated based on customers' activity over the five complete capacity years (1 September to 31 August) immediately preceding the final investment decision date for the BBI (CMP B). The IRA is mean annual offtake; and
- new customers and recent customers (customers connected for less than two full capacity years during CMP B) have their IRAs estimated (but, for recent customers, taking into account any available information about their offtake).

For resiliency BBIs, the individual NPB for each customer is equal to the customer's IRA. This is equivalent to deeming the regional NPB of the regional demand group to be 1.

6.3 Calculate starting allocations (clause 43(1))

A customer's starting allocation for the BBI is the customer's individual NPB divided by the sum of all customers' individual NPBs.

As noted above, a customer's BBC for the BBI is calculated by multiplying the BBI's covered cost by the customer's allocation (clause 35(2)).

7 Treatment of embedded generation

NPB includes the sum of the quantified benefits (positive values) and disbenefits (negative values) that an embedded plant connected to a local network or grid connected plant are expected to receive from the relevant BBI. The cost of BBIs made by Transpower in the interconnected grid since July 2019 is allocated on a basis intended to reflect benefits derived from the grid.

For the simple method, net metering at points of connection to the grid is used (embedded generation is not explicitly modelled).

For the standard methods, modelling typically follows the approach Transpower takes to modelling the grid for grid planning and investment decisions. In carrying out this modelling, Transpower may model embedded plant with a capacity above 10MW as if it were grid-connected (clause 49(5)). If Transpower does this, the modelled market benefits and disbenefits in respect of the plant must be attributed to the relevant host customer, not the owner of the plant. The benefits or disbenefits accruing to the modelled embedded generation are attributed to the host customers, which may result in distribution customers receiving BBCs for embedded generation that injects to the grid via the distribution network.

A distribution customer can also be placed into a supply group even if we do not model their embedded generation. This is done if these customers are historically net injectors into the grid i.e., injection IRA > offtake IRA.

8 Changes to allocations over time

Once determined, the starting BBI allocations are adjusted if certain events occur, referred to as "Benefit-based charge (BBC) adjustment events".

The BBC adjustment events are listed in clause 81(1) of the TPM. Most of them result in immediate step changes to allocations, although not necessarily immediate changes to BBCs for all affected beneficiaries.

While allocations may change following an adjustment event, regional customer groups are unlikely to change (unless the "Substantial sustained change in grid use" adjustment event applies, which results in a full recalculation for any affected BBIs). In the same manner, if a customer is not categorised within a regional customer group before an adjustment event, the customer will remain outside of this group afterwards (unless the customer connects a large facility, >10MW, that qualifies as part of such regional customer group[12]).

Several adjustment events also apply to large embedded plant (e.g. large embedded plant connection or disconnection, including large upgrades and large de-ratings (clause 85), and substantial sustained increase in large embedded plant consumption or generation (clause 86)). Changes to allocations because of these adjustment events are attributed to the relevant host customer.

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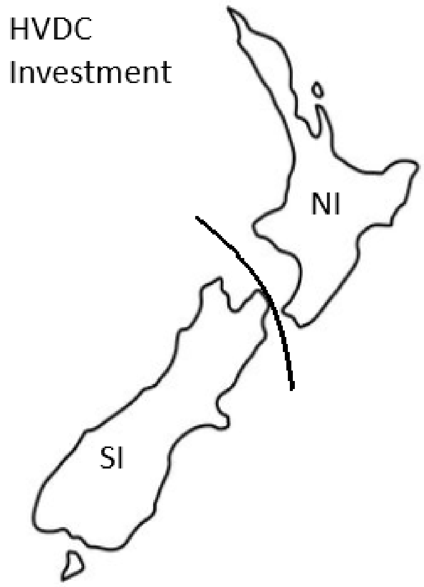
12 An example of this occurring would be an industrial user installing a large embedded generator. Clause 85(2) requires a large plant connection to be treated as a separate new customer (the notional new customer).

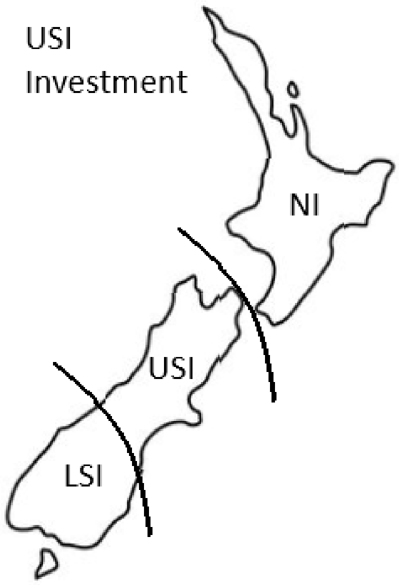
Appendix A Determining regional customer groups for BBIs with market benefits

Regional demand and supply groups

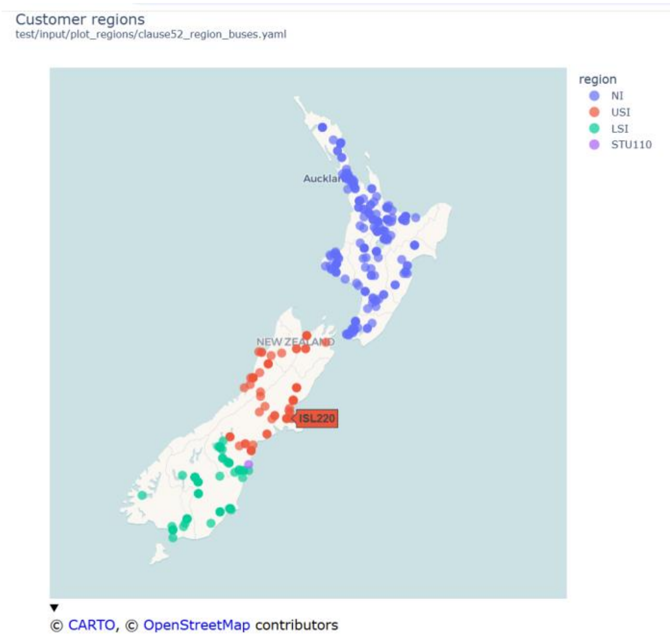
Benefit-based investments with market benefits will alleviate a transmission constraint. The first step in determining TPM allocations is to divide the transmission grid into electrical regions that are affected differently by that constraint. If the investment is on the HVDC link, then there will only be two regions: the North Island, and the South Island – see HVDC Investment below.

If the investment is on the AC network, then there will be at least two regions on the island where the constraint is (one either side) – see USI Investment below. The other island will also be a region, because the HVDC link flow direction and whether it is binding will affect the impact of the AC investment.





In practice we use an algorithm that groups substations according to the correlation[13] between load marginal costs (price) at each bus in the counterfactual (without the investment) scenario. This is a practical automated method that also lets us check that that the modelling gives intuitive regions.



Depending on the parameters used and the complexity of the constraint(s), the grouping algorithm may produce too many regions, introducing false precision. In these cases, we might use our judgment to group small regions together. Another consideration in determining regions is that the investment must cause a change in time weighted average price that is the same sign (positive or negative) for every bus in a region.

Demand or supply?

The change in load marginal cost in a region will affect supply and demand customers differently, so these groups are separated.

Stochastic dispatch modelling (SDDP[14]) provides the load supplied and price at each bus and the generation for each plant, for every hour in the modelled horizon[15]. These quantities are post-processed to give the present value of estimated market benefit and disbenefit (PVEMBD) at each bus (load) and plant (generation)[16].

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13 The correlation between the vectors of prices at two buses over every timestep and every hydro scenario.

14 https://www.psr-inc.com/software/sddp.html

15 These quantities are also modelled for every hydro inflow, renewable resource profile, and market (EDGS) scenario.

16 The method of calculation for PVEMBD differs for clause 51 and clause 52 of the TPM.

The bus and plant PVEMBDs are mapped to customer/locations using the intra-regional allocator (IRA) table and another table that maps generating plants to customers.

Whether a customer/location is classified as supply or demand depends on the magnitude (not the sign – i.e., positive or negative) of its supply and demand PVEMBD. In most cases this is trivial as customer/locations either supply or draw load, not both. A few customer/locations that have comparable supply and demand PVEMBD magnitudes (to within 50%) are classified as "Generation with load" or "Load with generation".

Further splitting

Different generation types have different costs and intermittency and will benefit differently from the alleviation of a transmission constraint. We split the regional supply groups by generation types: run-of-river hydro, storage hydro, wind, thermal peaker, thermal commit, geothermal, solar and battery. In the rare case where a customer has more than one generation type at a location, we assign the type with the largest PVEMBD magnitude.

Load customers are split between non-industrial (EDBs) and industrial customers that connect directly to the grid. At locations with both EDB and industrial customers, the share of PVEMBD is adjusted so that PVEMBD due to load growth is allocated to EDBs, which is consistent with demand forecast assumptions. The share of load PVEMBD at a location is also adjusted to remove the influence of step loads.

At this point all customer-locations are classified in what we call "potential regional customer groups", e.g. NI_wind, NI_geo, SI_storage, USI_Non_industrial, NI_gen_with_load, ….

This specification of regional customer groups supports the goal of providing customer allocations that are broadly proportionate to positive net private benefits.

According to clause 47, only regional customer groups with positive NPB are considered in allocations. RCGs with negative regional NPB, their contribution to total regional NPB, and the customer-locations they contain, are all excluded from the remaining calculations.

Recombining into final regional customer groups

Some provisional regional customer groups, e.g. USI_solar, might contain few customer/locations and introduce a risk of false precision in allocations. The goal is to group together customer/locations that have similar benefits in proportion to the size of their offtake or injection. For each provisional group we calculate the ratio of total group PVEMBD to the total group IRA offtake or injection. We then rank the provisional groups by this ratio, from highest to lowest. Working down through the provisional groups, a group joins the preceding (higher ranked) group if its PVEMBD/IRA ratio is greater than 80% of that of the preceding group (see section 3.3.6.13 of the Assumptions Book).

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