TRANSPOWER

TPM DETERMINATION:

BBC Assumptions Book

Version: 1.1

Date: 16 March 2023

Version history

Version	Published	Key amendments compared to previous version
1.0	15 September 2022	n/a
1.1	16 March 2023	Benefit factors added (Chapter 5), minor updates and errors corrected (Chapters 2 and 3). Version history added.

Contents

Chapter 1
Introduction

1.1 Background and purpose

1. The new 2022 TPM (referred throughout this document as the TPM) published by the Electricity Authority (**Authority**) in April 2022 contains the structural and fundamental aspects of the new transmission pricing regime.[1] The TPM includes a role for secondary documentation.[2] Under the TPM's requirements for benefit-based charges (**BBC**s), Transpower must consult on and publish a BBC assumptions book (**assumptions book**).

2. This assumptions book contains the assumptions and detailed methodologies Transpower intends to apply for allocating and adjusting BBCs (calculating starting BBI customer allocations for post-2019 BBIs and adjusting BBCs).[3]

3. This assumptions book covers both of the standard methods (price-quantity method and resiliency method) and the simple method for calculating starting BBI customer allocations for post-2019 BBIs and following a BBC adjustment event.[4] The TPM does not specify what material it must contain. This assumptions book takes a relatively detailed approach, intended to provide greater (up-front) certainty about how BBCs will be allocated and adjusted under the TPM.

4. The assumptions book is not intended to replicate, and cannot change, the fundamental and structural requirements for allocating or adjusting BBCs, which are specified in the TPM itself.

5. All clause references are to clauses in the TPM, unless stated otherwise.

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1 The Authority's decision paper and the TPM are available on the Authority's website.

2 Secondary documentation must include the assumptions book (that relates to BBC and is the subject of this consultation) and the Prudent Discount Practice Manual and may include a Reassignment Practice Manual.

3 A post-2019 BBI is a BBI commissioned after 23 July 2019. There are also some pre-2019 BBIs (**Appendix A BBIs**), the starting BBI customer allocations for which are specified in Appendix A of the TPM and therefore do not need to be calculated. However, the assumptions book will be relevant to how the BBCs for the Appendix A BBIs are adjusted.

4 The standard methods are used for high-value (> $20m) post-2019 BBIs. The simple method is used for low-value (≤ $20m) post-2019 BBIs.

1.2 Status of this assumptions book

6. The assumptions book is non-binding, except as otherwise stated in the TPM.

7. However, where Transpower makes a material departure from the assumptions book we must provide information about the departure and consult on it when we consult on our application of the relevant BBC allocation or adjustment methodology.

8. The assumptions and methodologies set out in the assumptions book must be consistent with the Code, including the TPM.

1.3 This assumptions book is a living document

9. The assumptions book is a living document that will be updated from time to time. For example, updates may be appropriate if MBIE updates its electricity demand and generation scenarios (**EDGS**), as Transpower and stakeholders gain experience with the allocation and adjustment of BBCs,[5] and if there are changes to generation nameplate capacities or new generation. Chapter 4 of the assumptions book will be updated for each subsequent simple method period.

10. We note that stakeholders can write to us at any time with information relevant to the content of the assumptions book.

11. We note also that for every high-value post-2019 BBI Transpower will consult on proposed starting customer allocations for the BBC. The proposed starting allocations will reflect future applications of the assumptions book. There may be feedback received and decisions made that flow back to an update to the assumptions book itself.

12. Under the TPM, Transpower must consult with customers on any proposed update to the assumptions book, subject to limited exceptions that mirror those that apply to the Authority's consultation on Code amendments under section 39(3) of the Electricity Industry Act 2010.

13. This means Transpower is not required to consult on an update to this assumptions book if we determine:

    a. the update is technical and non-controversial, or

    b. there is widespread support for the update among customers, or

    c. there has been adequate prior consultation on the update so that all relevant views of customers have been considered.

14. As noted above, Transpower must also consult specifically on any material departures from the assumptions book.

15. Transpower must review the content of the assumptions book at least every seven years and consider whether any content of the assumptions book is appropriate for incorporation in the TPM. This is to ensure that any assumption or methodology in the assumptions book that proves resilient over time can be assessed for inclusion as a binding requirement for BBC allocation or adjustment.

16. When consulting on amendments to the assumptions book – or on applications of the assumptions book to a BBI – we intend to allow time for both submissions and cross-submissions.

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5 For every high-value post-2019 BBI Transpower will consult on the proposed starting BBI customer allocations for the benefit-based charge. There may be feedback received and decisions made that flow back to an update to the assumptions book.

17. We have named the first edition of the assumptions book v1.0. We plan to label future updates as follows:

a. by one decimal place (e.g. update from 1.0 to v 1.1) where the update is considered to be minor. An example of a minor update would be:

   - an update that has not been consulted on in the circumstances mentioned above, or
   - where consultation has occurred via another channel (e.g. via consultation on proposed starting BBI customer allocations for a particular high-value BBI)

b. by a full version number (e.g. update from 1.1 to v2.0) when a major update has been made. For example, when substantive changes have been made as the result of consultation on the contents pf the assumptions book itself.

1.4 Glossary

18. The table below presents the acronyms and terms used throughout this assumptions book. Terms defined in the TPM have the same meanings in the assumptions book.

Term	Meaning
Authority	Electricity Authority
BBI consultation documents	The documents produced to support the consultation on the proposed starting BBI allocations for each high-value post-2019 BBI
Capex	Capital expenditure
Code	Electricity Industry Participation Code 2010
Constraint	A local limitation in the transmission capacity of the grid required to maintain grid security or power quality
Contingency	An unplanned event in the power system, including loss of a transmission asset
EPNPB	Expected positive net private benefits
FTR	Financial transmission rights, a mechanism to manage locational price risk
HVDC link	High voltage direct current inter-island link, the transmission link between the North and South Islands
Investment test	The investment approval test under section III of Part F of the Electricity Governance Rules 2003 (now revoked) or the Transpower Capex IM
kVAr	KiloVolt Ampere reactive (reactive power)
kWh	KiloWatt hour (energy)
MBIE	Ministry for Business, Innovation & Employment
MWh	MegaWatt hour (energy)
Opex	Operating expenditure
OptGen	The generation expansion tool used by Transpower. See PSR | OptGen — Model for generation expansion planning and regional interconnections (psr-inc.com)

Pre-contingent load management	Load management that results from the application of a pre-contingent market constraint.
Pre-contingent market constraint	A security constraint applied by the system operator in the wholesale electricity market, usually limiting transmission flow over one or more circuits, affecting the dispatch and prices.
RAB	Regulatory asset base
SDDP	The market model used by Transpower. See Software | PSR – Energy Consulting and Analytics (psr-inc.com)
SPD	The scheduling, pricing, and dispatch tool used by the system operator for dispatching generators, creating prices, and forecasting dispatch and prices
SPS	Special protection scheme
System condition	The load and generation patterns Transpower uses to highlight transmission issues we can reasonably expect to occur with currently available information and trends. See Transmission Planning Report 2021.pdf (transpower.co.nz)
TPM	Transmission pricing methodology
Transpower IPP	Individual price-quality path economic regulation that applies to Transpower
TWAP	Time weighted average price
VoLG	Value of lost generation
VoLL	Value of lost load

Chapter 2
Input assumptions for the price-quantity method

2.1 Introduction to this chapter

19. The purpose of this chapter is to specify the numerical input assumptions we will use when applying the price-quantity method (one of the standard methods for calculating starting BBI customer allocations for high-value post-2019 benefit-based investments (**BBIs**)).

20. This chapter is structured in two parts:

- Section 2.2 contains the assumptions for standard economic parameters for all BBIs under the price-quantity method
- Section 2.3 contains detailed modelling assumptions, primarily used to calculate market regional net private benefit (**RNPB**) for market BBIs under the price-quantity method. Some assumptions in section 2.3 may also be used to calculate ancillary service and reliability RNPB for ancillary service and reliability BBIs respectively.

21. This chapter does not include assumptions that will change frequently or on an investment-by-investment basis (e.g. BBI-specific changes to the transmission network, demand, and new generation scenarios), which we will present when consulting on the starting BBI customer allocations for individual BBIs.

22. Throughout this chapter we have included background information to help stakeholders understand the assumption and its relevance.

2.2 Assumptions for economic parameters

2.2.1 Discount rate

Assumption

23. We will use a default discount rate (**standard method rate**) of 7% p.a. (pre-tax, real).

Background

24. The TPM requires regional net private benefits (**RNPB**) to be discounted to a present value using the standard method rate, reflecting that benefits at the end of the standard method calculation period should be given less weight than those at the beginning due to the time-value of money. The TPM requires the standard method rate be the discount rate used in the investment test (if a tested investment), otherwise:

    a. the rate specified in this assumptions book, or

    b. if there is no applicable rate in the assumptions book, the rate in clause D6(3)(a) of the Transpower Capex IM.

25. The 7% p.a. rate is chosen for consistency with clause D6(3)(a) of the Transpower Capex IM, which prescribes a default discount rate of 7% to be used in the investment test when undertaking a cost-benefit analysis for different investment options.

26. Prior to consultation on the draft assumptions book, we considered using a lower discount rate (e.g. the Treasury public sector discount rate)[6] given interest rates were substantially higher when the discount rate prescribed in the Transpower Capex IM was originally derived.

27. However, in the interest of consistency with the rate used in the investment test, we will use the 7% rate for discounting private benefits through the TPM. We also use the 7% discount rate as an input to OptGen (see section 2.3), which influences the timing of new generation.

2.2.2 Assumptions around cash flows

2.2.2.1 Inflation and escalation

Assumption

28. RNPB is specified in real terms, which means that inflation is not applied to future RNPB and is calculated according to the prices of inputs in the year the analysis is prepared.

Background

29. Inflation and escalation are often confused. Inflation is defined as an increase in general prices throughout the full economy. Escalation refers to an increase in the cost of inputs relevant to an activity. The rate of escalation can be different to the inflation rate, and the

6 NZ Treasury Cost Benefit Analysis Primer: Public Sector Discount Rates for Cost Benefit Analysis, available at https://treasury.govt.nz/publications/guide/public-sector-discount-rates-cost-benefit-analysis-html.

rate of escalation may differ between inputs. It may therefore be appropriate to include escalation in the analysis where this is clearly forecast.

30. No adjustments to the standard method rate are made to account for future inflation or escalation, as the standard method rate is a real discount rate. In other words, our modelling is done in real terms.

2.2.2.2 Taxes

Assumption

31. We assess RNPB as pre-tax.

Background

32. We assess RNPB as pre-tax for consistency with the investment test and the standard method rate.[7]

2.2.3 Standard method calculation period

33. This section describes how we determine when the standard method calculation period (the analysis period for calculating RNPB) for a BBI begins, its duration, and the year the RNPB is discounted to (time zero).

Assumption

34. The TPM requires the duration of the standard method calculation period to be the lesser of 20 years or the end of the useful life of the BBI. To determine the useful life of the BBI, we use the physical asset lives used to calculate depreciation and revenue under the Transpower IMs.[8] The standard physical asset lives from the Transpower IMs are shown below:

Asset	Useful life
Substations	55
Transformers	55
Oil Containment	45
Switchgear	45
220/110/66 kV Two Zone Bus Protection	15
22/11 kV Neutral Earthing Resistor	45
Transmission Lines	55

7 While the Capex IM does not explicitly specify the discount rate as pre-tax, real, it was in the original grid investment test (the predecessor to the investment test), and it has been our standard practice to interpret the discount rate as pre-tax, real since then.

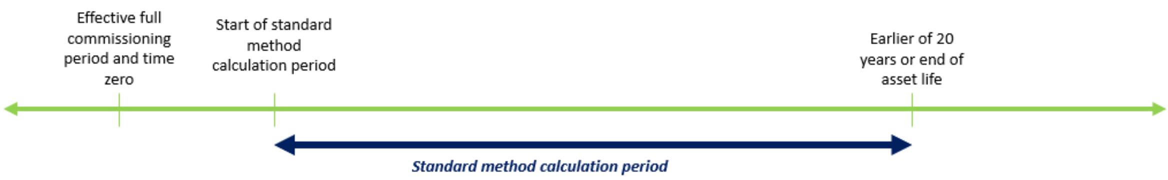
8 Schedule A, Transpower Input Methodologies Determination 2010.

Background

35. The TPM requires the standard method calculation period to begin on the first 1 January after the effective full commissioning date of the BBI, and the year to which the RNPB is discounted (**time zero**) to be the year in which the effective full commissioning date occurs (i.e. always one year before the start of the standard method calculation period).

36. The effective full commissioning date is the date by which we expect the BBI will be in a commissioning state sufficient to release all of the BBI's principal benefits. This date will be on or after the BBI's expected commissioning date (the date the first asset or transmission alternative comprised in the BBI is commissioned) and may be before the BBI's expected full commissioning date (the date the last asset or transmission alternative comprised in the BBI is commissioned).

37. The standard method calculation period for a BBI is depicted in the following diagram.



2.3 Modelling assumptions

38. We use SDDP (developed by PSR) as our wholesale market model.[9] SDDP simulates the wholesale electricity market by calculating a least cost optimal dispatch over the required time horizon (i.e. the standard method calculation period). The costs being optimised by SDDP include the variable and fixed system operating costs (e.g. generation fuel costs) plus penalties for the violation of constraints (e.g. hydro spill penalties).

39. We also use PSR's OptGen model[10] to determine the location, timing, and technology of new generation, which is an important input to the wholesale market model. We have included some of the key assumptions used by OptGen in section 2.3.8.

2.3.1 Market scenario formation

Assumption

40. Consistent with MBIE's 2019 EDGS, and as shown below, we assume the modelling assumptions described in this chapter are the same in each market scenario, except electricity demand (section 2.3.3) and the cost declines applied to potential new generation stations (section 2.3.8.9).

41. For illustrative purposes, we have included results from our 2021 demand forecast (gross electricity demand excl. Tiwai, incl. AC transmission losses) in the table below:[11]

	Reference	Growth	Global	Environmental	Disruptive
Demand	Reference (53 TWh in 2050)	Growth (58 TWh in 2050)	Global (46 TWh in 2050)	Environmental (63 TWh in 2050)	Disruptive (67 TWh in 2050)
New generators	Moderate cost declines for geothermal, wind, solar, batteries	Moderate cost declines for geothermal, wind, solar, batteries	Conservative cost declines for geothermal, wind, solar, batteries	Moderate cost declines for geothermal, wind, solar, batteries	Advanced cost declines for geothermal, wind, solar, batteries

9 PSR | SDDP — Stochastic hydrothermal dispatch with network restrictions (psr-inc.com).

10 PSR | OptGen — Model for generation expansion planning and regional interconnections (psr-inc.com).

11 Because we update the demand forecast each year we have not included specific values in the assumptions book.

Background

42. We are required to use market scenarios when calculating RNPB. Given the extensive consultation we have undertaken on modelling scenarios as part of the NZGP project, the market scenarios in this assumptions book are based on those described in the most recent NZGP scenario consultation.[12] In turn, the NZGP scenarios are reasonable variations of the MBIE's 2019 EDGS,[13] shown below:

    a. Reference: Current trends continue

    b. Growth: Accelerated economic growth

    c. Global: International economic changes

    d. Environmental: Sustainable transition

    e. Disruptive: Improved technologies are developed.

43. As described in paragraphs 238 to 252 we may change (including adding or removing) market scenarios for any given BBI. Any changes or additions to the market scenarios will be disclosed when we consult on the starting BBI customer allocations for the BBI.

2.3.2 Transmission network

2.3.2.1 Existing network

Assumption

44. Transmission network properties, including the bus voltage, line resistance and reactance, and the line limits are from Transpower's asset capability information system, which is the same system used to provide network information from the grid owner to the system operator.

Background

45. We use network properties from the asset capability information system as it is the best representation of the transmission network.

2.3.2.2 Changes to the network

Assumption

46. We assume an HVDC north flow capacity of 1071 MW for north flow, and 762 MW for south flow.

47. From 2030, we assume limits of 1400 MW north and 950 MW south.

Background

48. The current HVDC capacity is 1200 MW for north flow and 850 MW for south flow. However, there are constraints on the HVDC to ensure system security that can limit transfer to below these limits due to the configuration of the network and the availability of HVDC ancillary equipment. The HVDC limits we have used to determine this assumption are based on Transient Over Voltage (**TOV**) and Power Voltage (**PV**) limits (as described in Transpower's

12 NZGP1 Scenarios Update - December 2021.

13 Electricity demand and generation scenarios: Scenario and results summary (mbie.govt.nz).

Bipole Operating Policy) applied to the forward looking and final pricing schedules in the market system (on average between December 2015 and November 2021 (inclusive)). The TOV and PV limits result in reductions of HVDC capability due to outages of DC and AC equipment that provide reactive support. Because there are several components affecting the limits and because HVDC transfer could frequently be high in the future, either due to Tiwai leaving or due to wind generation replacing thermal, it is unlikely that outages can be re-scheduled to prevent these limits from binding with the current reactive components that make up the HVDC system.

49. We model an HVDC upgrade at the start of 2030, with the limits increasing to 1400 MW for north flow, 950 MW for south flow. We assume any constraints due to TOV and PV limits will be removed by additional reactive equipment commissioned at the time of the upgrade.

50. The timing of the HVDC upgrade is based on information in the 2021 Transmission Planning Report (**TPR**).[14]

2.3.2.3 HVDC transmission losses

Assumption

51. Losses are assumed to have a purely quadratic dependence on power flow in accordance with Ohm's laws (i.e. losses equal I2R and therefore are proportional to Power2). The coefficients below were derived from the losses at maximum transfer (66 MW of losses when sending 1200 MW north, and 35 MW when sending 850 MW south), given in Transpower's Bipole Operating Policy. The formulae for losses are:

$$Losses_{North} = (4.583 \times 10^{-5}) \times (Power_{North})^2$$

$$Losses_{South} = (4.844 \times 10^{-5}) \times (Power_{South})^2$$

52. Prior to the HVDC upgrade, we have assumed 1,071 MW of north flow capacity and 762 MW of south flow capacity on the HVDC. We approximate this quadratic relationship by splitting HVDC transfer in 50 MW tranches and using the incremental (i.e. marginal) losses in each tranche, as shown in the table below:

Flow (MW)	Losses North (%)	Losses South (%)
0 - 50	0.23%	0.24%
50 - 100	0.69%	0.73%
100 - 150	1.15%	1.21%
150 - 200	1.60%	1.70%
200 - 250	2.06%	2.18%
250 - 300	2.52%	2.66%
300 - 350	2.98%	3.15%

14 See section 6.9: Transmission Planning Report 2021.pdf (transpower.co.nz).

350 - 400	3.44%	3.63%
400 - 450	3.90%	4.12%
450 - 500	4.35%	4.60%
500 - 550	4.81%	5.09%
550 - 600	5.27%	5.57%
600 - 650	5.73%	6.05%
650 - 700	6.19%	6.54%
700 - 750	6.65%	7.02%
750 - 800	7.10%	7.32%
800 - 850	7.56%	N/A
850 - 900	8.02%	N/A
900 - 950	8.48%	N/A
950 - 1000	8.94%	N/A
1000 - 1050	9.40%	N/A
1050 - 1071	9.72%	N/A

53. Following the assumed HVDC upgrade in 2030, losses at a given level of transfer on the HVDC will fall. The exact dependence of losses on flows will depend on the final design of the upgrade. We assume the same amount of power is lost at maximum flow (66MW for north flow and 35MW for south flow). Again, we assume increasing marginal loss by tranches as shown in the table below:

Flow (MW)	Losses North (%)	Losses South (%)
0 - 50	0.17%	0.19%
50 - 100	0.51%	0.58%
100 - 150	0.84%	0.97%
150 - 200	1.18%	1.36%

200 - 250	1.52%	1.75%
250 - 300	1.85%	2.13%
300 - 350	2.19%	2.52%
350 - 400	2.53%	2.91%
400 - 450	2.86%	3.30%
450 - 500	3.20%	3.68%
500 - 550	3.54%	4.07%
550 - 600	3.87%	4.46%
600 - 650	4.21%	4.85%
650 - 700	4.55%	5.24%
700 - 750	4.88%	5.62%
750 - 800	5.22%	6.01%
800 - 850	5.56%	6.40%
850 - 900	5.89%	6.79%
900 - 950	6.23%	7.17%
950 - 1000	6.57%	N/A
1000 - 1050	6.90%	N/A
1050 - 1100	7.24%	N/A
1100 - 1150	7.58%	N/A
1150 - 1200	7.91%	N/A
1200 - 1250	8.25%	N/A
1250 - 1300	8.59%	N/A
1300 - 1350	8.92%	N/A
1350 - 1400	9.26%	N/A

2.3.2.4 AC transmission losses

Assumption

54. Transmission losses on the AC network above 66kV are included in our demand forecast rather than as an endogenous variable in SDDP. To account for the additional generation required due to AC losses, we add an additional 2.85% on to North Island demand and 3.85% on to South Island demand.

Background

55. We typically model AC transmission losses as an increase in demand rather than as a function of transmission flow because:

    a. modelling AC transmission losses as a function of transmission line flow significantly increases SDDP's run time, and

    b. increasing demand instead makes assessing and reviewing the outputs of SDDP more straightforward (and therefore less prone to error), because prices are the same across the grid without losses, other than for transmission constraints.

56. In general, we do not expect this assumption to materially affect RNPB unless loss benefits form a large proportion of the efficiency benefits of a BBI and we are using clause 52 of the TPM. Where this is the case, we will reassess the materiality and of this assumption, and the practicality of alternative assumptions.

2.3.3 Demand

Assumption

57. We have not included demand forecasts in the assumptions book as they are updated annually based on new information from customers and consumers. We will use demand forecasts for calculating RNPB that are consistent with those used for the application of the investment test to the BBI.

Background

58. For information, we provide a brief description of our demand forecasting process below.

59. We first forecast half hourly demand at a GXP level, and then convert them to 21 weekly load blocks for use in SDDP. To account for future levels of demand growth to be different to historic levels we have developed a two-stage forecasting method.

60. In the first stage of our demand forecasting methodology, we create a forecast of underlying demand growth. This is done at a national, island, regional and GXP level.

61. The base energy for national, island, and regional levels is assumed to grow at a constant rate, with a different rate for each market scenario. Island and regional energy demand is proportioned out based on recent historical values.

62. The correlation coefficients between historical peak and energy are determined for each region, both islands, and nationally. Each season is assumed to be correlated with annual energy. The energy and peak are gross of all embedded generation and include the demand from the industrial loads. The peak forecasts are then created by applying the correlation coefficients to the energy forecasts.

63. The peak forecasts at a GXP level are largely informed by the relevant line company's expectations of growth.

64. In stage 2 of the method, we forecast the effect that drivers such as electric vehicles, residential solar photovoltaic panels, residential battery storage, and electrification of industrial processes may have on future demand. Stage 2 of the method is assumption driven, in that the model forecasts the effect that various uptake rates of these new drivers will have on demand. National EV, residential solar, process heat, and battery storage uptake forecasts are from (or reasonable variations of) the EDGS.

2.3.3.1 Embedded generation

Assumption

65. We model the following embedded generators,[15] which means we model the loads at these GXPs as gross load and later calculate the net benefit/disbenefit to the gross load and embedded generation (see chapter 3, paragraphs 331 to 335 for more detail on this process). We only model embedded generators that meet the definition of "large plant" in the TPM.

Transmission node	Associated EG	Source	Transmission customer
BPE220	TaraW1	Table 15.41 of Powerco AMP	Powerco
EDG220	Edgcmb (Bay Milk)	Section 6.3.1.1.1 of Horizon AMP	Horizon
GLN220	Glenbrk[16]	Transpower operational data	NZ Steel
TWH220	Te Uku and Te Rapa	Table 1.2.4 of WEL AMP	WEL Networks
HWA110	Hawera (Whareroa)	Transpower operational data	Whareroa Cogeneration Limited
KAW110	Kawerau_TAM, Onepu_TA2, Onepu_TA3, Onepu_TOPP1, and Onepu_KA24	Section 6.3.3.1.4 of Horizon AMP and Transpower operational data	Horizon (Kawerau_TAM) and Norske Skog
KIN110	Kinleith	Table 15.41 of Powerco AMP	Powerco
KOE110	Ngawha and Ngawha3	Table 1.2 of TOP Energy AMP	TOP Energy

15 In this context, embedded generators are any generator >10 MW not connected to the transmission grid – i.e. generators connected to distribution networks or behind the meter of a major consumer. Commercial and residential-scale generators are modelled as part of our demand forecast.

16 Note, this generating station is partially embedded, but is modelled as a single generating station in SDDP.

KPI110	Kapuni[17]	Transpower operational data	Nova Energy
LTN220	TaraW2	Table 15.41 of Powerco AMP	Powerco
MAT110	Aniwhenua	Section 6.3.4.1 of Horizon AMP	
MHO110	Mangahao	Section 2.2 of Electra AMP	Electra
ROT110	Wheao	Transpower operational data	Unison
TGA110	Kaimai	Table 15.41 of Powerco AMP	Powerco
WIL220	Mill Creek	Section 3.4.4 of WE AMP	Wellington Electricity
WKM220	Mokai[18]	Table 3.3. of TLC AMP	Mercury
WRK220	Rotokaw and Tauha1	Section 4.1.3 of Unison AMP	Unison
ASB066	Highbank	Section 4.2.2 of EA Networks AMP	EA Networks
HWB220	Waipori1A and 1 unit of Waipori2A (unit 1)[19]	Figure 3.5 of Aurora AMP and information from Manawa Energy	Aurora (for Waipori at HWB)
HWB220	Mahiner_s1	Figure 3.5 of Aurora AMP	Aurora
NMA220	White Hill	Authority	Powernet
STK066	Cobb	Page 57 of Network Tasman AMP	Network Tasman

Background

66. At most GXPs we model net demand – i.e. demand as measured at the grid exit point. However, at the above GXPs we model embedded generation (**EG**) to reflect possible changes to the operation of EG in response to the different system conditions modelled in SDDP, which is likely to result in more accurate RNPB than modelling net demand. We do not

17 We model Kapuni cogeneration at KPI, but the load at KPA. KPI is connected to KPA by a single spur line so this is electrically equivalent. We map Kapuni cogeneration to KPA when calculating market benefits and disbenefits – see section 3.3.6.

18 Note, Mokai is not embedded but supplies some load to The Lines Company. The transmission charges for both Mokai generation and The Lines Company load at Whakamaru are recovered from Mercury; therefore, the transmission customer for this generator is Mercury.

19 See paragraph 100 for a full description of how we model the Waipori scheme.

attempt to model all EG because smaller EG are represented as reductions to net demand as measured at the GXP.

67. However, because the demand at each GXP is based on load profiles from 2016/2017, any embedded generation that has entered since that time is not reflected in our demand forecasts at each GXP. Therefore, we have also modelled several smaller EG that have entered since 2016/2017.

2.3.4 Existing Generators

68. This section describes our assumptions for existing generators, where existing is as at the end of 2021.

2.3.4.1 Generation outages

Assumption

69. We model generation outages as a fixed constant deduction from plant capacity, such that the capacity represents the average available capacity over time after accounting for planned and forced outages. Exceptions to this are:

    a. thermal peaking stations are de-rated for forced outages only, as we generally expect scheduled outages to occur outside peak periods

    b. wind and solar are not de-rated, as capacity factors for intermittent plant is usually inclusive of outages

    c. batteries are not de-rated as SDDP does not currently have the ability to de-rate batteries

70. Our generation outage assumptions for each existing station are presented in the following sections.

Background

71. Outage rates are implemented in SDDP for each station using composite outage rates (**COR**). The assumed COR values are listed in the tables below. SDDP multiplies each station's maximum capacity is multiplied by (1-COR/100).

72. It would be more precise to model the variation of plant capacity throughout the year that we expect to occur due to planned generation outages. However, this would require determining a maintenance schedule which would add complexity to the modelling, a degree of false precision, and make interpretation of results more difficult. In particular, we would need to consider how generation outages would be optimally scheduled, which would ideally need to consider market conditions at the time of the outage (which is not possible in SDDP).

2.3.4.2 Generation capacities

Background

73. There is not a consolidated and regularly updated public summary of the capacity of existing generation units. In general, we have used the 2020 generation stack reports where these

specify the capacity of the existing generators we model.[20] Where they do not, or where we consider there is a more accurate alternative, we have used other sources, including:

a. information provided by MBIE to Transpower as an underlying assumption used in the 2019 EDGS

b. Transpower operational data

c. resource consents

d. the Authority[21]

e. asset management plans

f. press releases.

74. Our assumptions for each existing station are presented in the following sections.

2.3.4.3 Thermal

Assumption

75. We model the following thermal generators:

Name	Alternative name	Fuel	Capacity (MW)	Composite outage rate (%)	Heat rate (GJ/MWh)	VOM ($/MWh)
P40	Huntly Unit 6	Natural gas	50.8	3	10.5	9.7
Kinleit	Kinleith	Process heat	40.0	30	n/a	9.6
TaranCC	Taranaki Combined Cycle	Natural gas	377.0	15	7.4	5.2
Glenbrk	Glenbrook	Process heat	112.0	55	n/a	9.6
Kapuni	Kapuni	Natural gas	25.0	0	9.3	5.1
Hawera	Whareroa	Natural gas	68.0	0	9.3	5.1
TeRapa	Te Rapa	Natural gas	44.0	0	11.7	4.9
Whirina	Whirinaki	Diesel	155.0	3	10.9	11.6

20 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/nz-generation-data-updates.

21 https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_fleet/Existing.

E3p	Huntly Unit 5	Natural gas	403.0	7	7.4	5.2
HuntC1	Huntly Unit 1	Coal	250.0	22	10.9	11.6
HuntC2	Huntly Unit 2	Coal	250.0	22	10.9	11.6
SFDOCGT	Stratford peakers	Natural gas	210.0	3	8.9	9.4
McKee	McKee peaker	Natural gas	100.0	3	10.5	9.4
JnctnRd	Junction road peaker	Natural gas	100.0	3	10.5	8.2
Edgcmb	Edgecumbe	Natural gas	10.0	0	11.5	4.9
HuntC4	Huntly Unit 4	Coal	250.0	22	10.9	11.6

76. We assume the following monthly generation (in MW) for the following cogeneration plants:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Kapuni	16.8	19.8	19.5	19.4	20.2	17.1	15.5	19.4	20.8	20.9	19.6	17.3
Hawera	37.3	35.5	32.3	31.7	29.1	18.9	29.6	30.1	35.3	34.7	36.2	35.8
TeRapa	41.2	40.6	39.2	35.7	15.2	10.7	21.7	41	41.3	41.7	41.1	39.6
Edgcmb	1.78	2.0	1.94	1.53	1.04	0.86	0.94	2.48	2.1	1.93	1.72	1.82

77. The following plants are modelled as unit commitment, which means that a plant must either generate for the entire stage or not generate at all for that stage (a stage is either 1 week or 1 month depending on the execution options within the model). The following plants have a unit commitment and a minimum generation constraint based on historical data:

a. Taranaki Combined Cycle (min. gen. 170 MW)

b. Huntly Unit 5 (min. gen. 175 MW)

c. Huntly Unit 1 (min. gen. 100 MW)

d. Huntly Unit 2 (min. gen. 100 MW)

e. Huntly Unit 4 (min. gen. 170 MW) – we have also added a start-up cost of $10M to this unit, treated as a “soft constraint” to disincentivise operation, but not included as a cost in the calculation of producer benefits (see section 3.3.6.10).

Background

78. Composite outage rates are based on plant availability factors in MBIE's thermal generation stack with the following exceptions:

    a. composite outage rate for peaker units (P40 (Huntly Unit 6), Whirinaki, SFDOCGT (Stratford Peakers), McKee, Junction Road, and Bream Bay). These are set to 3% to align with the Authority's Security Standards Assumptions Document[22]

    b. composite outage rate for Glenbrook and Kinleith cogenerators. Outage rates are set so that annual production match recent historical operation

    c. composite outage rate for other cogens (Kapuni, Hawera, Te Rapa, and Edgecumbe). These are set to zero as these plants have monthly forced generation based on recent historical operation.

79. Cogeneration plants often have dispatch patterns that do not align with expected (ordinary) behaviour. This is because they are heavily influenced by circumstances external to the electricity market. We use three approaches for dealing with cogeneration:

    a. Kinleith and Glenbrook are modelled with a pseudo fuel type called "process heat" which has zero cost and zero emissions. Plants with this fuel type are de-rated (using a composite outage rate) such that they produce an annual energy output consistent with historical production of the plant. The profile of these plants is flat throughout the year

    b. Bombay, Meremere, and Hinuera are not modelled in SDDP and the generation from the plant is subtracted from the demand forecast

    c. Kapuni, Te Rapa, Hawera (Whareroa), and Edgecumbe are modelled with the actual fuel type retained (natural gas) but the plant is given a forced generation pattern derived by taking an average of historical data for recent years.

80. The start-up cost for the third Huntly Rankine unit has been included to reflect that a third Rankine unit typically only operates when the system is in an extended period of shortage (e.g. during a dry year).

2.3.4.4 Hydro

Assumption

Inflows

81. Incremental inflow data for each gauging station are obtained from the EMI,[23] with the specific inflow series used for each station described below. We use the full set of available historical inflows available from EMI, which as at 2021 are the 89 inflow years from 1932-2020.

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22 Authority, Security Standards Assumptions document, November 2012, at https://www.ea.govt.nz/assets/dms-assets/14/14134SSAD-2012-v0-6.pdf

23 Authority, EMI (market statistics and tools) (ea.govt.nz).

Waikato

82. The Waikato hydro network is modelled as shown in the diagram below, consistent with the description of the network in the hydrological modelling data base.[24] There is a split bus at the Arapuni plant, so water from Lake Arapuni can be diverted into either Arapuni 1-5 or Arapuni 6-8, as shown in the diagram.[25] Note, Karapiro has a minimum outflow constraint of 148 cumecs.

24 HMD_Report4_HydroPowerSchemeBackgroundAndDescriptions_2021.pdf.pdf (windows.net) Section 2.1.

25 Note, where a hydro station injects into electrical busses that are connected to different transmission circuits (e.g. Arapuni, Roxburgh) we have created two hydro generating stations in SDDP and have added a dummy station upstream without the ability to produce electricity. This dummy station can send water to either or both of the two downstream generating stations, therefore replicating the ability of the operator to direct water into the units connected to one or both of the transmission circuits based on the conditions on the grid at the time (e.g. it may be optimal to send all available water downstream of a transmission constraint rather than sharing it equally between all units at the station).

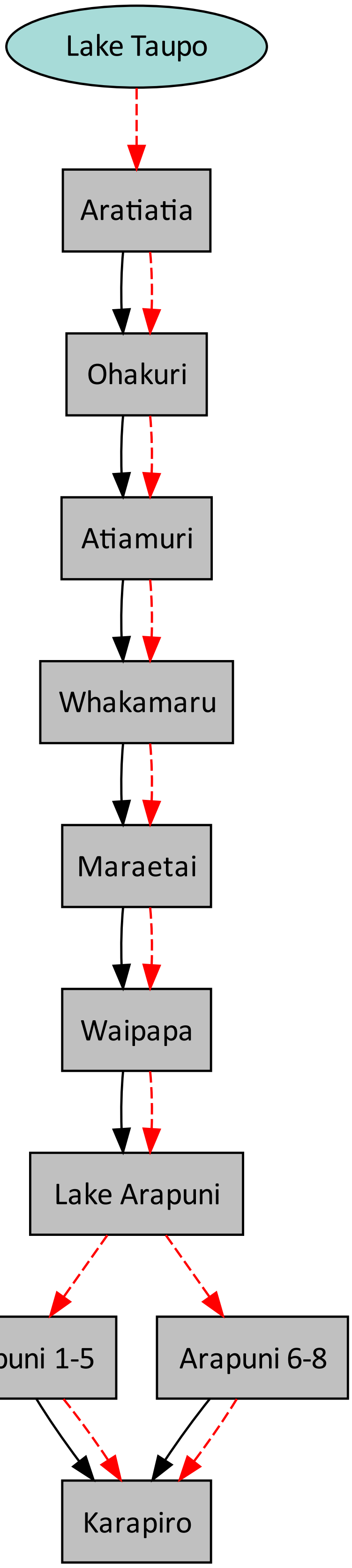

Figure 1: Waikato modelled topology

83. Lake Taupo is modelled with an available storage capacity of 764 hm^3. The following plants are modelled:

Name	Installed Capacity (MW)	Mean production coefficient (MW/cumecs)	Max turbining outflow (cumecs)	COR (%)	Modulation factor
Aratiatia	78.0	0.29	326.2	2	0.90
Ohakuri	106.0	0.27	390.0	2	0.50
Atiamuri	84.0	0.20	420.0	2	0.90
Whakamaru	124.0	0.37	335.8	2	0.90
Maraetai	352.0	0.49	722.0	2	0.90
Waipapa	54.0	0.13	381.0	2	1
Lake Arapuni	0.0	0	9999	0	0.80
Arapuni1-5	120.0	0.45	251.0	2	1
Arapuni6-8	72.0	0.45	150.7	2	1
Karapiro	96.0	0.26	371.0	2	0.90

84. Incremental inflow data for each gauging station is obtained from the EMI files listed below. The scale factors are used to estimate the proportion of the total tributary flow observed at Arapuni that occurs at each project down the Waikato River. Total Arapuni tributary flows are determined by deducting Taupo outflows from total flows at Arapuni. We originally obtained total flows for sites along the Waikato from the original Power Archive,[26] although the original data set is no longer publicly available.

Plant Name	Inflow Scale (incremental)	EMI filename
Aratiatia	0.064	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Ohakuri	0.162	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Atiamuri	0.018	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv

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Whakamaru	0.236	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Maraetai	0.321	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Waipapa	0.034	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Karapiro	0.178	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Lake Taupo	1	NI_TPO_Actual_LakeTaupoInfrastructure_Inflow_72790(1).csv
Lake Arapuni	0.165	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv

Waikaremoana

85. The Waikaremoana hydro network is modelled as shown in the following diagram, consistent with the description in the hydrological modelling database:[27]

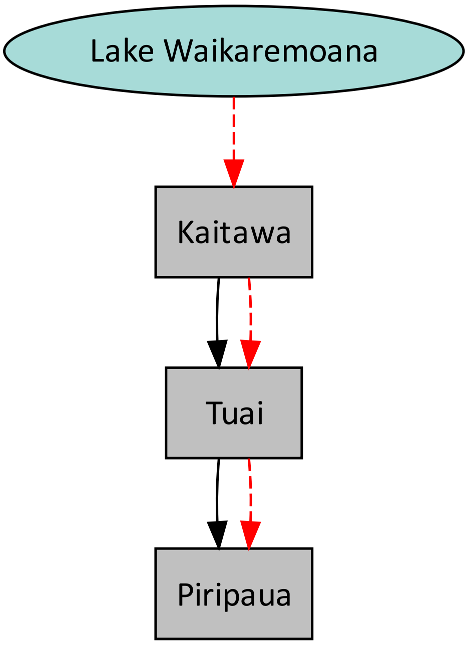

Figure 2: Waikaremoana modelled topology

[27] HMD_Report4_HydroPowerSchemeBackgroundAndDescriptions_2021.pdf.pdf (windows.net) Section 2.3.

86. Lake Waikaremoana is modelled with an available storage capacity of 161 hm^3 and inflow based on "NI_WKA_Natural_LakeWaikaremoana_Inflow_3650(1).csv" file from EMI. The following plants are modelled:

Name	Installed Capacity (MW)	Mean production coefficient (MW/cumecs)	Max turbining outflow (cumecs)	COR (%)	Modulation factor
Kaitawa	36.0	1.02	35.3	2	1
Tuai	60.0	1.70	35.3	2	1
Piripaua	42.0	0.90	46.7	2	1

Other NI Hydro

87. Other hydro units in the North Island are listed below:

Name	Installed Capacity (MW)	Mean production coefficient (MW/cumecs)	Max turbining outflow (cumecs)	COR (%)	Modulation factor
Rangipo	120.0	1.80	66.7	2	0.98
Tokaanu1-2	120.0	1.52	74.2	2	0.90
Matahina	80.0	0.51	157.0	2	0.92
Mangahao	32.4	1.40	21.4	2	0.85
Kaimai	41.9	1.57	25.5	2	0.90
Wheao	24.0	0.96	28.8	2	0.95
Patea	32.0	0.64	49.2	2	0.80
Aniwhenua	25.0	0.23	108.4	2	0.90
Tokaanu3-4	120.0	1.52	74.2	2	0.90

88. Inflows are modelled at the following stations:

Plant Name	Inflow Scale	EMI filename
Rangipo	1	NI_RPO_Actual_RangipoStationNonLinear_Inflow_92790(2).csv
Tokaanu	1	NI_TKU_Actual_TokaanuStationNonLinear_Inflow_92790(3).csv
Aniwhenua	1	NI_MAT_Actual_LakeMatahina_Inflow_93254(1).csv
Mangahao	1	NI_MHO_Actual_MangahaoStation_Inflow_97502(1).csv
Kaimai	1	NI_RHI_Actual_RuahihiStation_Outflow_14130(1).csv
Wheao	1	NI_WHE_Actual_WheaoStation_Outflow_15462(1).csv
Patea	1	NI_RTG_Actual_PateaStation_Outflow_34300(1).csv

Waitaki

89. The Waitaki hydro network is modelled as shown in the diagram below, consistent with the description in the hydrological modelling database.[28] Note, Upper Ohau River has a minimum outflow constraint of 8 cumecs 1 May-31 Oct and 12 cumecs 1 Nov-30 Apr, and Waitaki has a minimum outflow constraint according to the below table.

90. These values are based on the minimum flow defined in the HMD, except from October to March, when the minimum outflow can regularly be lowered to 170 cumecs for irrigation purposes:

Month	Minimum outflow (cumecs)
Jan-Mar	170
Apr	172
May	162
Jun-Jul	158
Aug	162
Sep	172
Oct-Dec	170

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Oct	135
Nov	140
Dec	150

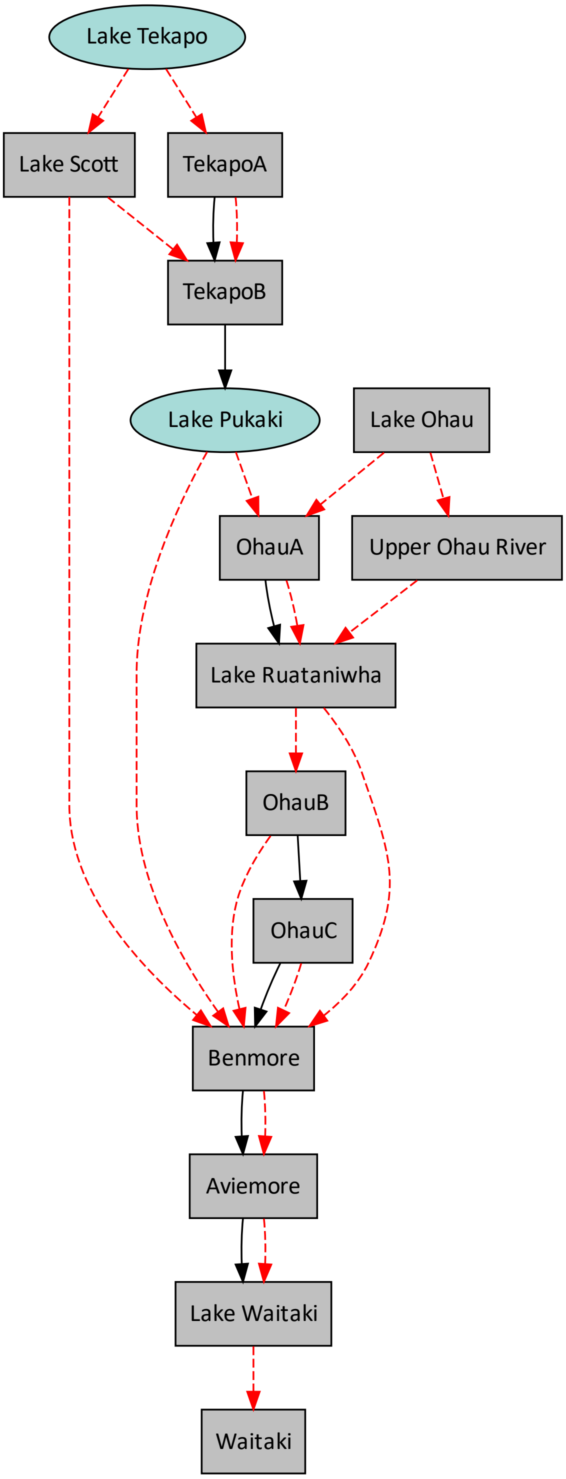

Figure 3: Waitaki modelled topology.

91. The following lakes are modelled:

Name	Min storage level (hm^3)	Max storage level (hm^3)
Lake Tekapo	23.9	699.8
Lake Pukaki	0	2,425 (30.9 alert storage)[29]

92. The following plants are modelled:

Name	Installed Capacity (MW)	Mean production coefficient (MW/cumecs)	Max turbining outflow (cumecs)	COR (%)	Modulation factor
TekapoA	30.0	0.232	129.3	2	1
TekapoB	160.0	1.285	124.5	2	1
OhauA	264.0	0.501	526.9	2	1
OhauB	212.0	0.417	508.4	2	0.90
OhauC	212.0	0.417	508.4	2	1
Benmore	540.0	0.818	660.1	2	0.50
Aviemore	220.0	0.310	709.7	2	0.80
Waitaki	90.0	0.162	555.6	2	0.80

29 Alert storage refers to stored water that is only used by SDDP as a last resort before shedding load (by penalising it at a cost of 1.1 times the most expensive thermal plant). In this instance, the alert storage represents the bottom 0.2m of Lake Pukaki's range which cannot be used as efficiently due to operational limitations at Ohau A when the lake is at that level (so would rarely be used).

93. Incremental inflow data is obtained from the EMI files in the table below. The tributary flows at Aviemore and Waitaki are a scaled version of the tributary flow at Benmore. The scaling factor is obtained using total flow data from the original Power Archive,[30] although the original data set is no longer publicly available. The Ohau outflows are deducted from the Benmore inflows, since Ohau inflows are modelled directly in our SDDP model.

Plant Name	Inflow Scale	EMI filename
LakeTekapo	1	SI_TEK_Natural_LakeTekapo_Inflow_98770(2).csv
LakePukaki	1	SI_PKI_Natural_LakePukaki_Inflow_98770(1).csv
LakeOhau	1	SI_OHU_Natural_LakeOhau_Inflow_98614(3).csv
Benmore	-1	SI_OHU_Natural_LakeOhau_Inflow_98614(3).csv
Benmore	1	SI_BEN_Actual_LakeBenmoreCombined_Tribflow_98615(2).csv
Aviemore	-0.4	SI_OHU_Natural_LakeOhau_Inflow_98614(3).csv
Aviemore	0.4	SI_BEN_Actual_LakeBenmoreCombined_Tribflow_98615(2).csv
Waitaki	-0.217	SI_OHU_Natural_LakeOhau_Inflow_98614(3).csv
Waitaki	0.217	SI_BEN_Actual_LakeBenmoreCombined_Tribflow_98615(2).csv

30 HMD_Report2_FlowsMethodologyAndDescription_2021.pdf (windows.net) Section 1.2.

Clutha

94. The Clutha hydro network is modelled as shown in the diagram below, consistent with the description in the hydrological modelling database.[31] Like Arapuni in the Waikato scheme, there is a split bus at the Roxburgh station, so water at Lake Roxburgh can be diverted into either plant Roxburgh 1-5 or Roxburgh 6-8. Note, Lake Roxburgh has a minimum outflow constraint of 250 cumecs.

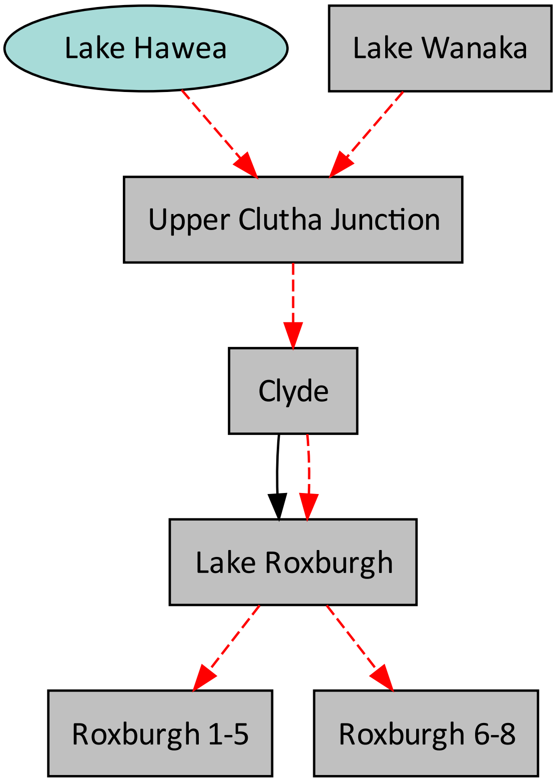

Figure 4: Clutha modelled topology

95. Lake Hawea is modelled with an available storage capacity of 1,142 hm^3. The below existing plants make up the Clutha scheme:

Name	Installed Capacity (MW)	Mean production coefficient (MW/cumecs)	Max turbining outflow (cumecs)	COR (%)	Modulation factor
Clyde	432.0	0.50	902.6	2	0.90
Roxburgh1_5	200.0	0.38	515.5	2	1
Roxburgh6_8	120.0	0.38	309.3	2	1

31 HMD_Report4_HydroPowerSchemeBackgroundAndDescriptions_2021.pdf.pdf (windows.net) Section 3.4.

96. Incremental inflow data is obtained from EMI for the following locations:

GaugingStation	InflowScale	EMI_filename
Lake Hawea	1	SI_HWE_Natural_LakeHawea_Inflow_9170(1).csv
Clyde	0.967	SI_ROX_Actual_LakeRoxburgh_Tribflow_99110(1).csv
Clyde	-0.967	SI_WAN_Natural_LakeWanaka_Outflow_9154(1).csv
Lake Wanaka	1	SI_WAN_Natural_LakeWanaka_Outflow_9154(1).csv
Lake Roxburgh	0.033	SI_ROX_Actual_LakeRoxburgh_Tribflow_99110(1).csv
Lake Roxburgh	-0.033	SI_WAN_Natural_LakeWanaka_Outflow_9154(1).csv

97. As shown in the diagram, Lake Hawea is modelled as being a controlled reservoir. However, any water released at Hawea does not directly generate any energy (as indicated by the red dashed line). At the same time, Lake Wanaka is modelled as a plant with no storage ability or related energy production. Both Lake Hawea and Lake Wanaka release water into the Upper Clutha Junction, which directs water into the Clyde plant. The incremental tributary flows at Clyde and Lake Roxburgh are calculated as proportions of the total tributary flow at Lake Roxburgh (again, based on the Power Archive). Note that the Lake Wanaka flow series has to be subtracted from the Clyde and Lake Roxburgh series in order to avoid double counting of inflows.

Waipori

98. The Waipori scheme is modelled as shown below, consistent with the description of the scheme in the hydrological modelling database.[32]

32 HMD_Report4_HydroPowerSchemeBackgroundAndDescriptions_2021.pdf.pdf (windows.net) Section 3.8.

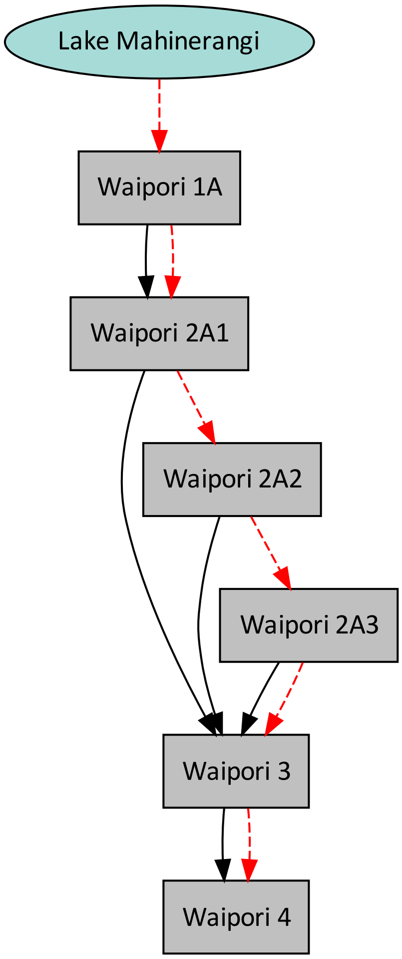

Figure 5: Waipori modelled topology

99. Lake Mahinerangi is modelled with an available storage capacity of 140.56 hm^3, with 34.60 hm^3 modelled as alert storage. The inflows to Lake Mahinerangi (mean of 7.5 cumecs) were provided to Transpower by Manawa Energy.

100. The following stations make up the Waipori scheme. We model Waipori2A as three separate units with one connecting to HWB220 and two connecting to BWK110. Waipori1A also connects to HWB220 and Waipori3 and Waipori4 connect to BWK110.

Name	Installed Capacity (MW)	Mean production coefficient (MW/cumecs)	Max turbining outflow (cumecs)	COR (%)	Modulation factor
Waipori1A	12.0	0.60	20	2	1
Waipori2A unit 1	19.0	1.5	12.5	2	1
Waipori2A unit 2	19.0	1.5	12.5	2	1

Waipori2A unit 3	19.0	1.5	12.5	2	1
Waipori3	7.0	0.35	20	2	1
Waipori4	8.0	0.40	20	2	1

Other SI Hydro

101. These are the remaining South Island hydro plants and storage lakes included in our modelling:

Name	Min storage level (hm^3)	Max storage level (hm^3)
Cobb	0	24.0
Coleridge	0	137.6
Manapouri	0	1029.1 (356.3 alert storage)[33]

Name	Installed Capacity (MW)	Mean production coefficient (MW/cumecs)	Max turbining outflow (cumecs)	COR (%)	Modulation factor
Cobb	32.0	4.65	7.7	2	n/a
Coleridge	39.0	1.20	32.5	2	n/a
Manapouri	800.0	1.531	522.5	2	n/a
Waipori	83.6	2.84	29.6	2	0.90
Highbank	25.0	0.80	31.4	2	0.90
Argyle	3.8	0.09	43.0	2	0.80

[33] Lakes Manapouri and Te Anau both have upper and lower ranges which have restrictions on the length of time storage can be in that range and the frequency with which those ranges can be used. These constraints cannot be modelled in detail by SDDP. To capture the approximate value of this storage, the upper range has been ignored, and the lower ranges have been modelled as "alert" storage.

Branch River	7.0	0.16	43.0	2	0.80

102. Inflow data is obtained from the following files:

GaugingStation	InflowScale	EMI_filename
Cobb	1	SI_COB_Natural_LakeCobb_Inflow_97904(2).csv
Coleridge	1	SI_COL_Actual_LakeColeridge_Inflow_97904(1).csv
Manapouri	1	SI_MAN_Actual_LakeManapouri(WithMararoaSpillAndMinFlowRegime)_Inflow_99552(1).csv
Waipori	1	SI_WPI_Actual_WaiporiStation_Outflow_174395(1).csv
Highbank	1	SI_HBK_Actual_HighbankStation_Outflow_7968(1).csv
Argyle & Branch River	1	SI_BRR_Natural_WairauRiverAtDipFlat_Flow_160114(1).csv

Background

103. SDDP operates via a two-step process:

a. establish the hydro operating policy through the calculation of water storage values. This step is referred to as the "policy step"

b. using the policy from step 1, simulate the operation/dispatch of the power system for a given (fixed) sequence of hydro inflows and renewable resource availability. This step is referred to as the "simulation step".

104. Within the policy step, we use synthetic inflow sequences that are derived from the actual inflows. The synthetic inflows reduce the level of fluctuations, help the model converge, and reduce computational run-time. We typically use up to 40 synthetic inflow sequences to determine the operating policy, which is a practical trade-off between precision and run-time. The synthetic inflows are produced by SDDP by analysing the relationship between an inflow sequence and time of year as well as the interdependence among inflows to different hydro plants.

105. Within the simulation step, we use the actual historical inflow sequences. We run the simulation across all available hydro inflow sequences. Despite the potential impact of climate change on inflows, we think the full set of historical inflows is preferable as it is an objective and reliable source.

106. The above subsections list the hydro networks that we model in SDDP, along with properties of each plant and reservoir. Many of the hydrological properties we use are based on historical data sets internal to Transpower that are not publicly available (e.g. modulation

factors, inflow scaling factors, min and max outflows). As part of this consultation, we welcome feedback from hydro asset owners on our assumptions.

107. We assume 2% composite outage rates for hydro stations based on the Authority's security standards.[34]

108. We model major hydro reservoirs as controlled storage (e.g. Lake Pukaki). The ability for run-of-river stations and stations downstream of a major reservoir to shift inflows across time is represented by a modulation factor (or regulation factor) – i.e. the ability to use its reservoir storage to transfer power generation across a stage. 1 indicates no storage capacity (flat production), 0 indicates that the plant is capable of full modulation (able to generate more during peak period at each stage).

109. To keep the modelling practical, we have decided to model a storage reservoir as controlled if the reservoir can store more than two weeks of its average inflow. The two-week limit was chosen because it is twice as large as the weekly time step that we use, and therefore water can be meaningfully stored in one time step for use in a later one.

34 Authority, Security Standards assumptions document, November 2012, at https://www.ea.govt.nz/assets/dms-assets/14/14134SSAD-2012-v0-6.pdf

110. All hydro topology diagrams are to be interpreted with the following key:

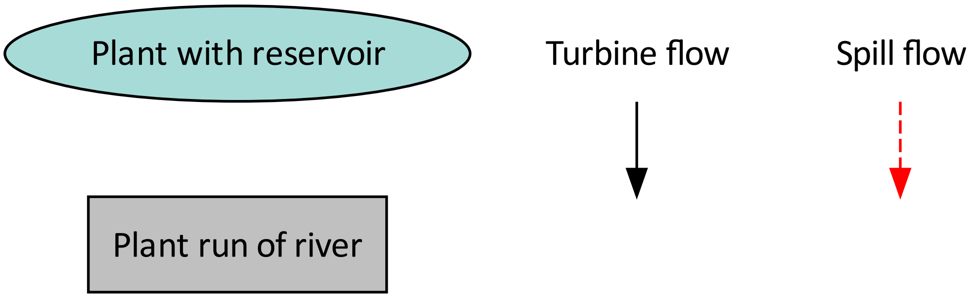

Figure 6: Key for interpreting hydro topology diagrams

A plant with a reservoir can store water for extended periods of time, while a run of the river plant only has limited storage capacity (see above comment on modulation factor). Plant outflow that passes through a turbine (hence injecting energy into the grid) is shown with a black arc, while outflow that bypasses turbines is shown with a red dashed arc. Red dashed lines represent water arcs in a scheme that do not directly create energy. In some schemes, like the Waitaki, these diversions can be used by an operator to inject energy into different parts of the grid.

111. Note that all red dashed arcs represent flows of water that do not produce energy (i.e. energy that is spilled around a station or released from a reservoir that has no generation units).

112. In this section, we describe the inflow at a station as it is loaded into SDDP. For a station at the top of a scheme, we obtain the total flow of water and for downstream stations, we obtain tributary or incremental flow. The tributary flow is defined as the flow entering the river between the station and any stations immediately upstream. For example (in Figure 1), the tributary flow at Ohakuri is from water entering the Waikato downstream of the Aratiatia station (excluding outflow from Aratiatia), but upstream of the Ohakuri station.

2.3.4.5 Geothermal

Assumption

Generator	Capacity (MW)	Composite Outage Rate (%)
Ohaaki	57.0	10
Pohipi	50.0	25
Mokai12	112.0	5
Kawerau_KAG	107.0	10
Te Mihi	166.0	10
Rotokawa	35.0	25

Ngawha	25.0	10
Ngatamariki	82.0	10
Nga Awa Purua	140.0	10
Tauhara 1 (Te Huka)	28.0	10
Wairakei	138.0	10
Ngawha Stage 3	31.5	10
Kawerau_TAM	25.0	10
Onepu_TA2[35]	16.0	10
Onepu_TA3	8.0	10
Onepu_TOPP1	26.6	10
Onepu_KA24	8.0	10

Background

113. Composite outage rates are assumed to be 90%, which is consistent with capacity factor assumption in MBIE's geothermal stack, except for Mokai, Rotokawa and Poihipi which are set consistent with the capacity factors from recent historical operations.

114. As a result of rising intermittency of other generation (i.e. new wind and solar), we assume geothermal plant will be converted to be to be fully flexible to increase/decrease output without a minimum operating constraint as per MBIE's geothermal generation stack.[36]

2.3.4.6 Wind

Assumption

Name	Capacity (MW)	Region
Mill Creek	60.0	Wellington
Tararua Wind Stage 1	34.3	Manawatu

35 Note that Onepu_TA2 is currently modelled as a process heat plant as it runs on wood chips.

36 See paragraph 5 of the Executive Summary.

Tararua Wind Stage 2	33.7	Manawatu
Tararua Wind Stage 3	93.0	Manawatu
Te Apiti	90.8	Wairarapa
Te Rere Hau	16.5	Manawatu
Te Rere Hau 3	16.0	Manawatu
Te Rere Hau 4	16.0	Manawatu
Te Uku	64.4	Waikato
West Wind	142.6	Wellington
Waipipi	133.3	Taranaki
Mahinerangi stage 1	36.0	Otago
White Hill	58.0	Southland

115. We also assume the following repowering dates for existing wind farms:

Plant	New Capacity (MW)	Repowering Year
Tararua Wind Stage 1	100.8	2029
Tararua Wind Stage 2	140.0	2034
Te Apiti	220.0	2034
Tararua Wind Stage 3	125.0	2037
White Hill	115.0	2037
West Wind	250.0	2039
Te Rere Hau	82.0	2041

Te Rere Hau 3	82.0	2041
Te Rere Hau 4	81.0	2041
Te Uku	110.0	2041
Mahinerangi stage 1	50.0	2041
Mill Creek	105.0	2044

116. We assume the below average capacity factors for wind farms located in each of the below regions. Capacity factors also vary throughout the day and year based on profiles from renewables.ninja (RN).[37]

Region	Latitude	Longitude	Average Capacity Factor
Far North	-35.0662	173.2644	43.1%
Northland	-35.8565	174.1195	42.0%
Auckland	-36.9207	174.6306	41.3%
Waikato	-37.6423	175.3608	39.4%
BoP-Taupo	-38.3208	176.1908	35.9%
Eastland	-38.7506	177.8471	41.2%
Central Plateau	-39.4129	175.8526	41.5%
Hawkes Bay	-39.2851	176.9056	39.7%
Taranaki	-39.6441	174.4115	39.5%
Manawatu	-40.3389	175.4799	41.2%
Wairarapa	-40.4998	176.1639	46.7%
Wellington	-41.183	174.9457	44.4%
Southern Wairarapa	-41.3505	175.6144	41.6%

37 Renewables.ninja

Marlborough	-41.799	173.9811	36.0%
West Coast	-41.8992	171.6139	24.4%
Canterbury	-43.386	172.4709	43.0%
Otago	-45.444	170.0638	39.6%
Southland	-46.1156	168.7271	43.6%

Background

117. The wind repowering assumptions have been developed by Transpower based on the following assumptions:

    a. wind farm repowering year – based on a 30-year life from the 2020 wind generation stack and the commissioning date from NZ Wind Association[38]

    b. turbines replaced with 4.2 MW turbines to 2029 based on the turbine size of recently commissioned and committed projects,[39] and after that 5MW turbines[40]

    c. wind farms with turbines less than 1.6MW currently see 50% reduction in turbine numbers, which is based on Tilt's expectation that output would increase by 200% for Tararua 1 and 2 following repowering, which is equivalent to an ~50% reduction in turbine numbers[41]

    d. we assume other wind farms will have a smaller (20%) reduction in turbine numbers given modern wind farms typically have larger turbines than the early wind farms in New Zealand.

118. Regional wind generation profiles are obtained from RN, which reads weather data from NASA's MERRA reanalysis model and converts them to wind power output using the Virtual Wind Farm (VWF) model written by Iain Staffell.

119. We obtained historical hourly wind generation profile by regions listed in the table below. Nineteen years of generation profiles from 2000 to 2018 were used to represent 19 wind scenarios, which vary generation in each stage and load block. We use Vestas V80 2000 as the turbine model with a hub height of 100m.

120. The profiles obtained from RN are then scaled up or down according to the below formula so their capacity factors align with MBIE's wind generation stack but preserve the seasonal and hourly variations in the RN dataset as much as possible.

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38 NZ Wind Farms operating and under construction (windenergy.org.nz).

39 See Table 5 of the 2020 wind generation stack.

40 See section 4.5, para 4 of the 2020 wind generation stack.

41 Based on Tilt's expectation that output would increase by 200% for Tararua 1 and 2 following repowering: Tararua re-powering could triple output: Tilt | Energy News.

121. The raw data from RN within a given region is denoted $\{x_1, x_2, x_3, \dots, x_N\}$ where $0 \le x_i \le 1$ provides the fraction of total renewable resource available during the *i-th* hour of the horizon. The untransformed capacity factor from RN is given by the average $\bar{x} = \frac{1}{N}\sum_{i=1}^{N} x_i$.

122. The goal is to transform the data $y_i = f(x_i)$ such that the new average $\bar{y}$ agrees with the MBIE capacity factor and that $0 \le y_i \le 1$ (because a capacity factor cannot be less than zero or greater than 1). To do this, we use the following transformation:

$$y_i = \left(\frac{\bar{y} - \bar{x}}{\overline{x^2} - \bar{x}}\right) x_i^2 + \left(1 - \frac{\bar{y} - \bar{x}}{\overline{x^2} - \bar{x}}\right) x_i$$

Where $\overline{x^2} = \frac{1}{N}\sum_{i=1}^{N} x_i^2$ is the mean of the squares. This transformation works provided $1 \ge \frac{\bar{y}-\bar{x}}{\overline{x^2}-\bar{x}} \ge -1.$

123. This quadratic transformation was chosen so that the greatest increase or decrease to hourly capacity factors occurs for periods with a capacity factor around 0.5. This is because we want to preserve the high and low capacity factors existing in the RN dataset. We note the transformation cannot always completely remove a difference between the target average capacity factor from MBIE and RN, because doing so would require hourly capacity factors greater than one or less than zero.

2.3.4.7 Batteries

Assumption

124. We model the following battery storage systems which presently exist within the network:

Name	Bus	Minimum Charge (MWh)	Maximum charge (MWh)	Initial Charge (p.u.)	Maximum Output Power (MW)	Charge Efficiency (p.u.)	Discharge Efficiency (p.u.)
Southdown	SWN220	0	2.0	0.5	1	0.92	0.92

Background

125. We identified existing batteries from information published by Mercury to NZX.

2.3.4.8 Decommissioning

Assumption

126. We assume the following retirement dates for thermal units:

Plant	Retirement Year
Taranaki Combined Cycle (TCC)	2025

Whirinaki	2029
Huntly Rankine Unit 1	2030
Huntly Rankine Unit 2	2030
Huntly Rankine Unit 4	2030
Edgecumbe	2033
Stratford Peakers	2035
E3p (Huntly Unit 5)	2037
McKee	2038
Hawera	2038
Kapuni	2040
Junction Road	2045

Background

127. These decommissioning assumptions are consistent with our assumptions in NZGP scenario development consultation,[42] which were based on decommissioning dates listed in MBIE's thermal generation stack, except for:

- Huntly's Rankine units (1, 2 and 4) are assumed to retire at Genesis' intended end date of coal fuelling in 2030
- Hawera and Kapuni's decommissioning dates are based on the 42-year project life from the older 2011 generation stack, and 1996 and 1998 commissioning dates from the 2020 thermal generation stack report.

2.3.5 Fuel Assumptions

Assumption

128. Our long-term fuel price assumptions are listed in the table below:

Year	Gas	Coal	Diesel	Biofuel[43]

42 TP Net Zero Grid Pathways – Consultation - Final 13 Jan'21.pdf (transpower.co.nz).

43 Only used for the new potential HLY_BioPkr generator.

2032	6.89	7.79	40.57	N/A
2033	6.89	7.79	41.54	N/A
2034	6.89	7.79	42.51	N/A
2035	6.89	7.79	43.47	25.00
2036	6.89	7.79	44.44	25.00
2037	6.89	7.79	45.40	25.00
2038	6.89	7.79	46.37	25.00
2039	6.89	7.79	47.34	25.00
2040	6.89	7.79	48.30	25.00
2041	7.84	7.79	48.30	25.00
2042	7.84	7.79	48.30	25.00
2043	7.84	7.79	48.30	25.00
2044	7.84	7.79	48.30	25.00
2045	7.84	7.79	48.30	25.00
2046	7.84	7.79	48.30	25.00
2047	7.84	7.79	48.30	25.00
2048	7.84	7.79	48.30	25.00
2049	7.84	7.79	48.30	25.00
2050	7.84	7.79	48.30	25.00

129. Short-term fuel prices are linearly interpolated between current year's price and the first year of long-term fuel prices.

Background

130. Long-term (2032 onwards) gas prices were provided by the Climate Change Commission (**CCC**),[44] while the long-term coal and diesel prices were provided to Transpower by MBIE as an underlying assumption used in the 2019 EDGS. The biofuel price was based on research by Scion, which estimated biofuel prices of ~$0.8/L,[45] which corresponds to $25/GJ (rounded to nearest $5/GJ) at an energy density for biofuel of 33.5 MJ/L. We assume biofuel is not available at scale until 2035. Note, we assume thermal plants that are fuelled by 'process heat' (see section 2.3.4.3) have no fuel costs (or carbon emissions) under the assumption that the fuel cost is primary attributable to the energy supplied to the industrial process.

131. Our fuel price assumptions for current year are obtained from the following sources.

a. Gas price – the most recent financial report from one of the generators e.g., Genesis' quarterly report

b. Coal price – average value from the following two sources:

i. the most recent financial report from one of the generators e.g., Genesis' quarterly report, for a stockpiled coal price for current year

ii. Enerlytica for an import parity coal proxy at Huntly, which we will disclose when used for each BBI as Enerlytica's coal proxy is not publicly available [46]

c. Diesel price - the most recent commercial diesel price published by MBIE.[47]

2.3.6 Emissions

2.3.6.1 Emission rates

Assumption

132. We assume the following emissions factors for each thermal fuel:

	Emissions factor
Coal	0.09 tCO2/GJ
Natural gas	0.05 tCO2/GJ
Diesel	0.07 tCO2/GJ
Process heat	0
Biofuel	0

44 https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Modelling-files/Scenarios-dataset-2021-final-advice.xlsx

45 Generic Confidential Client Report (scionresearch.com)

46 https://www.enerlytica.co.nz.

47 https://www.mbie.govt.nz/assets/Data-Files/Energy/nz-energy-quarterly-and-energy-in-nz/prices.xlsx.

133. For geothermal plants, we assume the following emissions rates:

Name	Existing or Future	Emission rate (gCO2eq./kWh)	Emission rate - with carbon reinjection (gCO2eq./kWh)
Ohaaki	Ex.	340	68.0
Pohipi	Ex.	39	7.8
Mokai12	Ex.	52	10.4
Kawerau_KAG	Ex.	123	24.6
TeMihi1	Ex.	43	8.6
Rotokaw	Ex.	84	16.8
Ngawha	Ex.	310	62.0
Ngatamariki	Ex.	64	12.8
Nga Awa Purua	Ex.	63	12.6
Tauhara 1 (Te Huka)	Ex.	45	9.0
WairakiNet	Ex.	21	4.2
Ngawha-3	Ex.	200	40.0
Tauhara-2a	Fu.	60	12.0
Tauhara-2b	Fu.	60	12.0
Ngawha-4	Fu.	200	40.0
Mangakino	Fu.	60	12.0
Mokai-4	Fu.	60	12.0
Ngatamariki-2	Fu.	60	12.0
Rotokawa-3	Fu.	60	12.0

Kawerau-2	Fu.	115	23.0
Rotoma-1	Fu.	115	23.0
TokaanuGeo1	Fu.	115	23.0
Tikitere-1	Fu.	115	23.0
Taheke-1	Fu.	115	23.0
Reporoa-1	Fu.	115	23.0
Tauhara-3	Fu.	60	12.0
Horohoro	Fu.	115	23.0
AtiamuriGeo	Fu.	115	23.0
Rotokawa-4	Fu.	60	12.0
TokaanuGeo2	Fu.	115	23.0
Tikitere-2	Fu.	115	23.0
Taheke-2	Fu.	115	23.0
Reporoa-2	Fu.	115	23.0
Ngawha-5	Fu.	200	40.0
Taheke-3	Fu.	115	23.0
Reporoa-3	Fu.	115	23.0
Ngawha-6	Fu.	200	40.0
Kawerau_TAM	Ex.	75	15.0
Onepu_TA3	Ex.	60	12.0
Onepu_TOPP1	Ex.	60	12.0
Onepu_KA24	Ex.	60	12.0

134. For the future geothermal plants, we assume the following emissions rates depending on the categorisation of each plant in the 2020 geothermal generation stack:

Emissions category for future plants	Emissions range estimate	Our interpretation (without carbon reinjection)
Low	40 – 80 g CO2eq/kWh	60 g CO2eq/kWh
Medium	80 – 150 g CO2eq/kWh	115 g CO2eq/kWh
High	> 150 g CO2eq/kWh	200 g CO2eq/kWh

Background

135. Emission rates for thermal plants were provided to Transpower by MBIE as an underlying assumption used in the 2019 EDGS. Biofuel is assumed to emit no CO2 (except for any fossil carbon used in the production of the delivered biofuel) as per New Zealand Biofuels Roadmap Technical Report published by Scion.[48]

136. To account for the variability of GHG emissions across the different fields and technologies, we apply an emission rate specific to each plant. These rates are consistent with Mclean and Richardson (2019).[49] We also assume that geothermal plants are able to capture and reinject their carbon emissions which reduce these emission rates by 80%, consistent with the options identified to reduce carbon dioxide emissions from geothermal plant described in section 2.4 of MBIE's geothermal stack report.[50] Without this assumption, we found the higher emitting plant (in particular) operates infrequently (i.e. is uneconomic), which is not consistent with the role geothermal generation is generally expected to play as an alternative to fossil-fuelled thermal plant.

48 Generic Confidential Client Report (scionresearch.com).

49 See the 2020 Geothermal generation stack update, and the NZ geothermal website (Greenhouse Gas Emissions from New Zealand Geothermal Power Generation in Context) for further details.

50 Future Geothermal Generation Stack (mbie.govt.nz).

2.3.6.2 Carbon prices

Assumption

137. We assume the following long-term carbon prices:

Year	Carbon Price ($ per tonne CO2e)
2032	146.85
2033	151.25
2034	155.79
2035	160.47
2036	165.28
2037	170.24
2038	175.35
2039	180.61
2040	186.02
2041	191.60
2042	197.35
2043	203.27
2044	209.37
2045	215.65
2046	222.12
2047	228.79
2048	235.65
2049	242.72
2050	250.00

138. Short-term carbon prices are linearly interpolated between current year's price and the first year of the long-term carbon prices.

Background

139. Our long-term (2032 onwards) carbon price assumption is based on the marginal abatement costs required to eliminate fossil fuels from the transport and energy sectors as identified in the CCC's Ināia tonu nei report.[51]

140. The carbon price for current year is the NZUs spot price obtained from Jarden Commtrade.[52]

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[51] Ināia tonu nei: a low emissions future for Aotearoa » Climate Change Commission (climatecommission.govt.nz) – see Figure 7.2.

[52] https://www.commtrade.co.nz/

2.3.7 Deficit costs

Assumption

141. We assume a deficit cost of $600/MWh in OptGen and SDDP.[53]

142. When using clause 52 of the TPM, we will:

   a. adjust prices in post-processing during periods of deficit to the lower of the deficit cost and the long-run marginal cost (**LRMC**) of self-supply generation if they are materially different

   b. assume the self-supply generation is diesel generation, and use the following assumptions to calculate its LRMC:

      i. capital cost of $2m/MW, variable O&M of $13.8/MWh, fixed O&M of $18.2/kW p.a., and fuel cost of $24/GJ[54]

      ii. heat rate of 9000 GJ/GWh, and diesel generator life of 30 years[55]

      iii. carbon emission factor: 74 tCO2e/TJ[56]

   c. use a deficit cost of $600/MWh during periods of energy shortage, and $10k/MWh during periods of capacity shortage.

Background

143. An important input to OptGen and SDDP is the cost of energy that cannot be supplied, referred to as the deficit cost. The deficit cost influences how stored water is used in SDDP, with higher deficit costs resulting in higher water values, and therefore a tendency for water to be held back in reserve for dry periods. Similarly, the deficit cost influences the generation being built by OptGen, with a higher deficit cost resulting in generation being built sooner as the consequence of running out of generation is greater, as well as to cover very unlikely situations of deficit (e.g. during a very rare dry inflow sequence).

144. We typically see deficit in two situations: during peak periods where there is not enough transmission and generation to meet peak demand, and during dry inflow periods where there is not enough energy to meet demand.

145. Clause 49(4) specifies that the maximum price that consumers will pay is their estimated cost of self-supply (**CoSS**) for electricity or alternative energy. More specifically, we assume the maximum average price received by consumers will be equal to the cost for an end-consumer to supply the electricity that is not supplied by the grid. In other words, the LRMC of a consumer installing behind-the-meter generation specifically to supply the load not supplied by the grid.

146. The CoSS is itself a function of the deficit cost:

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53 To prevent the model allocating all deficit to one bus we will implement this in three-tranches – 5% of demand at $600/MWh, the next 5% at $610/MWh, and the remaining 90% at $620/MWh.

54 MBIE's LCOE tool.

55 MBIE's 2011 NZ Generation Data Update.

56 IPCC, Co2 Emissions from Stationary Combustion of Fossil Fuels.

a. for a generator with a low capacity factor, the LRMC of any generation technology can be very high (mathematically, it approaches infinity as the capacity factor approaches zero).

b. it will only be economically rational for plant to be built if the capacity factor results in an LRMC that is lower than the cost of self-supply.

147. Therefore, in theory, the COSS could be as high as the deficit cost for rare situations of unsupplied load (e.g. an unexpected shortage of electricity due to an outage). In other words, it is not possible to separate the concepts of deficit cost from the CoSS. Given energy and capacity shortages from the grid are rare, the deficit cost is particularly relevant when assessing the CoSS for infrequent shortages.

148. A $600/MWh deficit cost during energy shortages was chosen to reflect the incentives existing in the market when there are energy shortages, but – if necessary – adjusting prices in post-processing to ensure the model is not over- or under-estimating the prices that would exist in the market in the long-term. This is most likely to occur if we are assessing the benefits of enhancing the grid in a region that does not have enough capacity and does not have enough flexible generation available to mitigate shortages.

149. The $600/MWh value for energy shortages is sourced from the analysis used to derive the minimum weekly amount (**MWA**) of $10.65/ICP/week[57] that consumers will receive in compensation from retailers during an official conservation campaign (OCC).[58] When an OCC is triggered, demand will be managed by the system operator in accordance with Part 9 of the Code, avoiding a complete shortage in electricity supply. However, by managing demand, retailers benefit from the reduced volumes they need to purchase from the market to cover their contracts with end consumers. The compensation scheme aims to ensure retailers are appropriately incentivized to avoid shortages by hedging with generators. Given the importance of compensation scheme and its relevance to this problem, and its similarity to a CoSS, we consider it appropriate to adopt the assumptions used to derive the MWA in our deficit cost value. Furthermore, a deficit cost of $600/MWh is similar to the CoSS of diesel generation, so adopting this value will minimize the need to adjust prices in post-processing.

150. We have used a similar approach for setting the $10k/MWh value for capacity shortages by sourcing it from the default scarcity pricing blocks that will be used in the market when real-time pricing is implemented.[59] Rather than using all three blocks, we are proposing to use the first (lowest) block only, because in general, we expect 5% of load shedding will be enough to mitigate most capacity shortages. A $10k/MWh value is higher than what we would expect to persist in the long-term. However, it is a realistic reflection of the high-value consumers place on electricity during peak periods (if these shortages do not occur frequently).

151. We have not modelled the $10k/MWh value in OptGen and SDDP because a deficit cost can only be specified for all load blocks. However, the inclusion of a firm capacity constraint (see section 2.3.8.11), ensures there is sufficient generation to meet peak demand on a national

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57 https://www.ea.govt.nz/assets/dms-assets/9/9609CustomerCompensationSchemeSummary2014.XLSX.

58 https://www.ea.govt.nz/assets/dms-assets/9/9610QAs-Mar11.pdf.

59 See Figure 3: Implementing real-time pricing.

basis, and broadly reflects economic investment to meet capacity shortages with a deficit cost of $10k/MWh.

152. In our view, the most credible alternative to diesel generation to supply consumers load is a solar + battery installation. We assessed the CoSS of a solar + battery installation to mitigate capacity shortages and found the LRMC significantly exceeded the CoSS of diesel generation in the same situation (in large part due to the intermittency of solar, and its inability to meet peak demand in winter even with significant battery storage). Therefore, we assume diesel generation is the technology used to self-supply.

153. We considered alternatives to this approach to setting the deficit cost/cost of self-supply:

    a. Including diesel generation as a modelled generator in OptGen. The advantage of this approach is OptGen could determine the diesel generation needed. However, because it is not possible for OptGen to accurately assess the intermittency problem and the stochastic dry year problem simultaneously, we will inevitably get some misalignment between OptGen and SDDP (too much or too little diesel generation built).

    b. Determining the deficit cost based on back-casting. We investigated this approach by varying the deficit cost and comparing actual storage levels with modelled storage levels for 2016 and 2017. However, the results were not sensitive to the deficit cost, and therefore we do not consider this to be a conclusive approach to determining a CoSS.

2.3.8 New generators

154. Transpower uses OptGen as its generation expansion model to determine new additions and retirements. This section covers some key assumptions used in OptGen.

2.3.8.1 Location of new generation

Assumption

155. We will disclose our assumptions of the location of new generation plants outside the assumptions book for each BBI.

Background

156. The EDGS do not specify the location of new generation – just national forecasts over time. We typically determine the location of new uncommitted generation by modelling grid constraints in OptGen.

157. By allowing grid constraints to influence the location of generation, we can assess the extent to which a transmission constraint is likely to influence generation expansion, without worrying about location decisions that aren't relevant to the investment being modelled. For example, an export constraint on the HVDC will limit the generation being built in the South Island, but it doesn't matter if the generator is located in Canterbury or Invercargill. To that end, we do not consider generation scenarios produced using this method to be precise forecasts of the location of new generation, rather they help us understand the extent to which a transmission project will benefit the electricity market.

2.3.8.2 Committed projects and earliest commissioning date

Assumption

158. Where we consider a project to be committed, we include it manually in all generation expansion scenarios. For other projects, we assume the following earliest commissioning dates:

	Consented	Unconsented
Wind	Current year + 2	Current year + 4
Solar	Current year + 1	Current year + 3
Geothermal	Current year + 4	Current year + 6
Batteries	N/A	Current year + 3
Thermal	N/A[60]	Current year + 4
Hydro	2037	2037
Biofuel peaker	N/A	2035

Background

159. Our earliest commissioning date assumptions were developed based on the following rationale:

    a. Consenting: consenting varies widely depending on the project – e.g. Puketoi took approx. 1 year,[61,62] whereas Meridian pursued consents for Project Hayes for six years before eventually withdrawing their application[63]. We assume a two-year consenting period for all projects, which is a balance between a typical consenting timeframe of one year and the possibility of much longer consenting periods (e.g. due to appeals)

    b. Wind: we assume a two-year construction period for wind stations based on recent projects – e.g. Waipipi,[64,65] and Turitea (North)[66,67]

60 Note, the only consented thermal project we are aware of is Todd's 360 MW Waikato Power Plant (three stages of 120 MW each). Todd recently advised it had made a decision not to proceed at this time. Therefore, we assume the earliest each stage can enter the market is 2026, 2027, and 2028 respectively.

61 Mighty River seeks consents for 53-turbine Puketoi wind farm | Energy News.

62 https://www.energynews.co.nz/news-story/wind/9129/mighty-river-gets-puketoi-consents.

63 Meridian withdraws application for Project Hayes | Energy News.

64 Construction at Waipipi to start soon - Tilt | Energy News.

65 Waipipi fully commissioned – Tilt | Energy News.

66 https://www.nzx.com/announcements/332511.

67 https://www.nzx.com/announcements/386511.

c. Solar: there have been no large-scale solar farms constructed in New Zealand. We assume they will take one year less than wind given the relative ease of construction (particularly less onerous civil/structural requirements)

d. Geothermal: we assume a 4-year construction period based on Tauhara timelines – e.g. Contact began drilling appraisal wells in 2019,[68] and most recently forecast construction completing in the second half of 2023[69] - a total period of ~4 years

e. Batteries: we assume a construction and consenting period of three years based on Meridian's timeline for their unconsented North Island battery project[70]

f. Thermal: we assume a construction period of two years based on recent projects – e.g. Junction Road,[71,72] and McKee[73,74]

g. Hydro: we assume no hydro is built before 2037 because of the recent absence of proposed and committed hydro projects, which may be due to the difficulty of consenting major hydro projects

h. Biofuel: we assume an earliest start date of 2035 given the lack of a biofuel market in New Zealand sufficient to fuel a large generator.

2.3.8.3 Hydro

Assumption

160. We assume the following:

a. capital cost at $5,100/kW, which is based on the range provided in MBIE's 2011 generation stack, inflated to 2021$ to align with other capital costs from MBIE's 2020 generation stack[75]

b. fixed operating and maintenance costs (FOM) at $47.5/kW-yr based on MBIE's 2020 hydro generation stack

c. variable operating and maintenance costs (VOM) at $0 based on MBIE's 2020 hydro generation stack (excluding the $8/MWh for transmission charges).[76]

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68 https://www.nzx.com/announcements/335222.
69 https://www.nzx.com/announcements/386902.
70 See slide 15: Presentation title (nzx-prod-s7fsd7f98s.s3-website-ap-southeast-2.amazonaws.com).
71 Todd moves ahead with Junction Road peaker | Energy News.
72 Todd commissioning Junction Road gas peaker | Energy News.
73 Todd to build $100m gas-fired peaker at McKee | Energy News.
74 Todd starts commissioning $100m McKee peakers | Energy News.
75 See table 5-3: 2011 NZ Generation Data Update (mbie.govt.nz).
76 We exclude transmission charges because it would be circular to include assumptions about transmission charges in the same model used to produce transmission charges.

Plant Name	Location	Capacity (MW)	Mean production coefficient (MW/m3/s)	Modulation factor
Mohaka	North Island	70	0.49	1
Motu	North Island	80	0.56	1
Whangaehu	North Island	50	0.52	1
Pukaki	South Island	35	0.12	0.8
Wairau	South Island	72	1.47	0.8
Rakaia	South Island	3	0.07	1
North Bank	South Island	260	0.16	0.5
Hawea Gates	South Island	17	0.24	0.5
Hawea River	South Island	80	0.17	1
Luggate	South Island	80	0.17	1
Queensberry	South Island	110	0.23	1
Dumbarton	South Island	100	0.11	1
Tuapeka	South Island	350	0.38	0.5
Barnego	South Island	80	0.09	1
UpWaiauSth	South Island	80	0.11	1
LoWaiauSth	South Island	60	0.08	1
WaiauCntbry	South Island	65	0.38	1
TaramTaipo	South Island	80	0.10	1
ArnoldValley	South Island	46	0.06	0.5
GreyRiver	South Island	250	0.32	0.3
Mokihinui	South Island	100	10.20	1

Ngakawau	South Island	24	2.45	1
Haast River	South Island	60	0.08	1
WaimakaB	South Island	84	3.50	0.9
WaimakaA	South Island	50	2.10	1

Background

161. Our list of potential new hydro plant is from MBIE's 2020 hydro generation stack.[77] This list includes 200 MW of potential new hydro in the North Island and 2,086 MW in the South Island (excluding the proposed Lake Onslow pumped hydro scheme).

2.3.8.4 Thermal

Assumption

162. We assume the following operational and financial assumptions:

	OCGT (incl. biofuel peaker)	CCGT
Capital cost ($/kW)	1,030	1,305
Heat rate (GJ/MWh)	11.8	7.6
COR (%)	3%	6%
VOM ($/MWh)	11.40	8.00
FOM ($/kW-yr)	4.60	11.40

163. The table below shows a list of possible future plants from the generation stack:

Plant	Max Build Capacity (MW)
Stratford CCGT	400
Huntly OCGT	500
Stratford OCGT	200

[77] Hydro generation stack update for large-scale plant (mbie.govt.nz).

Otorohanga Peaker U1 (OCGT)	120
Otorohanga Peaker U2 (OCGT)	120
Otorohanga Peaker U3 (OCGT)	120
HLY_BioPkr (OCGT)	1000

Background

164. Transpower's thermal generation stack is mostly based MBIE's 2020 thermal generation stack.[78] The only deviation from the stack is our COR assumption for OCGT and biofuel peaker which is based on the EA's assumptions in their security standards.

2.3.8.5 Geothermal

Assumption

165. We assume the following geothermal plants are available to be built:

Plant	Max Build Capacity (MW)	Capital cost if constructed in 2021 ($/kW)
Tauhara2a	152	4734
Tauhara2b	125	4734
Ngawha4	25	7802
Mangakino	25	6127
Mokai4	25	7802
Ngatamariki2	50	5568
Rotokawa3	50	5568
Kawerau2	50	5568
Rotoma1	25	7802
TokaanuGeo1	20	6335

78 2020 Thermal generation stack update report (mbie.govt.nz).

Tikitere1	50	5023
Taheke1[79]	25	5640
Reporoa1	25	6127
Tauhara3	30	5968
Horohoro	5	9767
AtiamuriGeo	5	9767
Rotokawa4	50	5568
TokaanuGeo2	100	5119
Tikitere2	50	5568
Taheke2	25	6127
Reporoa2	25	6127
Ngawha5	25	7802
Taheke3	25	6127
Reporoa3	25	6127
Ngawha6	25	7802

166. We also assume the following based on MBIE's 2020 geothermal generation stack:

a. FOM at $190/kW-yr

b. VOM at $0

c. COR of 10%.

79 Taheke1 has a discounted capital cost assumption to reflect $12M government funding via the Infrastructure Reference Group: [Government-Funding-Contracted-Sep-2021.pdf (crowninfrastructure.govt.nz).]

Background

167. Our geothermal generation stack is based on MBIE's 2020 geothermal generation stack.[80] The stack includes a total of 1,035 MW potential geothermal generation during the study period with capital costs ranging from $4,734/kW to $9,767/kW.

2.3.8.6 Wind

Assumption

168. The stack includes the following plants:

Name	Max Build Capacity, MW	Transmission Node	Wind Region	Capital cost if constructed in 2021, $/kW	Turbine O&M fixed cost, $/kW/year	Other fixed cost, $/kW/year
Turitea	221.4	LTN220	Manawatu	2089.70	25.00	20.98
Harapaki	176.3	RDF220	Hawkes Bay	2054.54	25.00	10.01
Mt Cass	92.4	WPR066	Canterbury	2133.71	25.00	15.13
Puketoi	300.0	LTN220	Wairarapa	2159.41	25.00	18.65
Castle Hill	500.0	BPE220	Wairarapa	2192.87	25.00	15.82
Kaiwera Downs	200.0	GOR220	Southland	2013.14	25.00	15.76
Awhitu	25.0	GLN033	Auckland	2037.28	25.00	16.64
CentralWind	150.0	TNG220	Central Plateau	2295.87	25.00	16.56
Mt Munro	100.0	MGM110	Wairarapa	1990.43	25.00	17.30
Waitahora	150.0	DVK110	Wairarapa	2273.57	25.00	18.87
Kaimai Wind	100.0	WKO110	Waikato	2103.17	25.00	16.20
Flemington	100.0	WPW110	Wairarapa	2202.77	25.00	17.53
Mahinerangi stage 2	150.0	HWB110	Otago	2104.20	25.00	16.27
Hurunui	80.0	ISL220	Canterbury	2401.29	25.00	19.91

80 Future Geothermal Generation Stack (mbie.govt.nz).

BOPTaupo_1	300.0	TRK220	Bay of Plenty	1889.49	25.00	14.08
Kaiwaikawe	60.0	MTO110	Northland	1927.02	25.00	14.97
Northland_1	300.0	MPE110	Northland	2266.78	25.00	17.71
Waikato_1	180.0	OHW220	Waikato	2293.08	25.00	17.40
Waikato_2	200.0	OHW220	Waikato	2198.27	25.00	16.55
Marlboroug_1	50.0	BLN033	Nelson-Marlborough	1993.88	25.00	16.42
Wellington_1	15.0	WIL033	Wellington	2578.00	25.00	20.98
Manawatu_1	150.0	BPE220	Manawatu	2183.23	25.00	16.77
BOPTaupo_2	300.0	WRK220	BOP-Taupo	1867.21	25.00	13.76
Wellington_2	100.0	HAY220	Wellington	2282.09	25.00	17.93
Auckland_1	100.0	HPI220	Auckland	2330.63	25.00	18.90
Manawatu_2	150.0	BPE220	Manawatu	1981.07	25.00	15.59
Auckland_2	100.0	HPI220	Auckland	2125.08	25.00	17.31
Northland_2	150.0	MPE110	Northland	2072.24	25.00	15.90
CentralPla_1	250.0	TKU220	Central Plateau	2059.44	25.00	14.12
BOPTaupo_3	150.0	WRK220	BOP-Taupo	2156.20	25.00	15.17
Eastland_1	50.0	TUI110	Eastland	1905.60	25.00	15.06
Northland_3	100.0	MPE110	Northland	2127.17	25.00	16.93
BOPTaupo_4	100.0	WRK220	BOP-Taupo	2565.24	25.00	19.89
Southland_1	100.0	GOR220	Southland	2028.62	25.00	17.03
BOPTaupo_5	75.0	WRK220	BOP-Taupo	2193.48	25.00	15.60
FarNorth_1	75.0	KOE110	Far North	2332.70	25.00	18.32
Otago_1	500.0	ROX220	Otago	1928.04	25.00	14.58

Waikato_3	20.0	WRK220	Waikato	2302.98	25.00	17.14
Southland_2	25.0	GOR220	Southland	2280.34	25.00	18.98
FarNorth_2	75.0	KOE110	Far North	2359.37	25.00	18.60
Eastland_2	75.0	TUI110	Eastland	2653.86	25.00	20.02
Southland_3	150.0	GOR220	Southland	2055.26	25.00	15.82
Waikato_4	50.0	WKM220	Waikato	2169.26	25.00	16.62
Wairarapa_1	100.0	MGM110	Wairarapa	2567.84	25.00	20.07
Eastland_3	200.0	TUI110	Eastland	2440.01	25.00	18.30
Otago_2	300.0	HWB220	Otago	1991.59	25.00	14.68
Manawatu_3	150.0	BPE220	Manawatu	1971.52	25.00	14.52
Southland_4	100.0	NMA220	Southland	2149.98	25.00	17.75
BOPTaupo_6	75.0	WRK220	BOP-Taupo	2511.21	25.00	18.73
Marlboroug_2	75.0	BLN110	Nelson-Marlborough	2250.77	25.00	17.63
Southland_5	50.0	NMA220	Southland	2351.04	25.00	19.66
SouthernWa_1	100.0	GYT110	Southern Wairarapa	2222.22	25.00	18.29
Southland_6	150.0	NMA220	Southland	2286.92	25.00	17.82
CentralPla_2	150.0	TNG220	Central Plateau	2081.32	25.00	14.66
Southland_7	100.0	NMA220	Southland	2394.58	25.00	19.70
FarNorth_3	200.0	KOE110	Far North	2335.85	25.00	18.79
Waikato_5	75.0	WKM220	Waikato	1905.47	25.00	14.73
Canterbury_1	15.0	COL066	Canterbury	2602.02	25.00	21.26
Otago_3	150.0	HWB220	Otago	2203.77	25.00	15.05
BOPTaupo_7	10.0	ARI110A	BOP-Taupo	2907.03	25.00	24.59

WestCoast_1	75.0	ROB110	West Coast	2184.30	25.00	15.36
Northland_4	100.0	MPE110	Northland	2599.44	25.00	20.39
Otago_4	150.0	HWB220	Otago	2465.41	25.00	19.01
BOPTaupo_8	150.0	WRK220	BOP-Taupo	2101.63	25.00	14.91
Northland_5	150.0	MPE110	Northland	2271.22	25.00	16.64
Manawatu_4	100.0	BPE220	Manawatu	2182.89	25.00	17.01
Canterbury_2	150.0	CUL066	Canterbury	2539.97	25.00	18.12
Canterbury_3	100.0	WPR066	Canterbury	2556.70	25.00	20.46
Eastland_4	150.0	TUI110	Eastland	3041.56	25.00	23.19
CentralPla_3	125.0	TKU220	Central Plateau	2574.32	25.00	19.74
Taranaki_1	100.0	SFD220	Taranaki	2071.12	25.00	17.30
Wellington_3	100.0	LTN220	Wellington	2222.03	25.00	18.16
Taranaki_2	200.0	SFD220	Taranaki	2181.13	25.00	15.75
Northland_6	100.0	MPE110	Northland	2162.58	25.00	16.50
Auckland_3	125.0	GLN220	Auckland	2190.75	25.00	17.00
SouthernWa_2	150.0	GYT110	Southern Wairarapa	2412.84	25.00	17.99
HawkesBay_1	100.0	RDF220	Hawkes Bay	2233.78	25.00	17.79
Auckland_4	150.0	GLN220	Auckland	2307.28	25.00	17.06
Canterbury_4	200.0	ISL220	Canterbury	2039.33	25.00	16.15
Taranaki_3	200.0	SFD220	Taranaki	2130.80	25.00	15.58
Manawatu_5	300.0	BPE220	Manawatu	1918.04	25.00	13.80

Background

169. Transpower's wind generation stack is based on a report[81] written by Roaring40s Wind Power Ltd for MBIE. The stack includes a total of 11,400 MW of potential wind generation with capital costs ranging from $1,867/kW to $3,042/kW if constructed in 2021. Project-specific details were provided to Transpower by Roaring 40s with no modification except to map projects from a region to a GXP/GIP.

170. Note, we use the same regional capacity factors for new wind generation as the existing wind generation (see section 2.3.4.6).

2.3.8.7 Solar

Assumption

171. We assume the following solar plants are available to be built. All plants have a FOM of $20/kWp-yr.

Transmission Node	Region	Max Build Capacity (MW)	Capital cost if constructed in 2021 ($/kW)
OHA220	Canterbury Region	200	1,452
OHC220	Canterbury Region	200	1,483
OHB220	Canterbury Region	200	1,504
BEN220	Canterbury Region	200	1,214
AVI220	Canterbury Region	200	1,210
STK066	Tasman Region	200	1,426
KAW110	Bay of Plenty Region	200	1,345
CYD220	Otago Region	200	1,295
WHI220	Hawke's Bay Region	180	1,368
ARG110	Marlborough Region	100	1,432
BLN033	Marlborough Region	140	1,516
TWH033	Waikato Region	200	1,360
GLN033	Waikato Region	200	1,333

81 Microsoft Word - Wind Generation Stack update V2.0 Final 30 June 2020 (mbie.govt.nz).

ASB066	Canterbury Region	200	1,386
WTU033	Hawke's Bay Region	200	1,335
RDF033	Hawke's Bay Region	200	1,332
BOB110	Waikato Region	200	1,363
WHU033	Waikato Region	120	1,423
HUI033	Taranaki Region	120	1,427
SVL033	Auckland Region	200	1,338
ISL066	Canterbury Region	200	1,447
ISL066	Canterbury Region	200	1,447
ISL066	Canterbury Region	200	1,446
MAN220	Southland Region	200	1,345
LTN033	Manawatu-Wanganui Region	160	1,384
BPE033	Manawatu-Wanganui Region	160	1,363
HLY220	Waikato Region	200	1,241
HLY220	Waikato Region	200	1,243
KPU066	Waikato Region	120	1,363
BRB033	Northland Region	120	1,378
TNG011	Manawatu-Wanganui Region	120	1,322
OAM033	Otago Region	120	1,407
TMK033	Canterbury Region	100	1,404
WRK220	Waikato Region	100	1,422
CUL033	Canterbury Region	60	1,500
ASY011	Canterbury Region	80	1,534
HWB110	Otago Region	200	1,271

MST033	Wellington Region	120	1,358
HAM033	Waikato Region	200	1,404
BRY066	Canterbury Region	200	1,518
FKN033	Otago Region	140	1,486
ARI110	Waikato Region	100	1,396
HIN033	Waikato Region	60	1,500
NMA033	Southland Region	120	1,365
INV033	Southland Region	200	1,378
TKR033	Wellington Region	180	1,386
CST033	Taranaki Region	140	1,683
TMU011	Waikato Region	80	1,691

Background

172. Transpower's solar generation stack is mostly based on a report written by Alan Miller for MBIE,[82] with project-specific details provided to Transpower by Alan Miller with no modification except to map each project to a bus in each region. We have selected price scenario 0 (new normal base case) and production scenario 0 (higher worldwide solar module production forecast). The stack includes a total of 7,740 MW potential solar generation shortlist during the study period with capital costs ranging from ~$1,200/kW to ~$1,700/kW (including land and connection costs, and if constructed in 2021).

173. The capital cost for the near-term plants has been selected as the lower end of the capital cost range from the MBIE solar generation stack to reflect that they are more likely to be built first.

174. We model 181 solar profiles across the country by substation. A list of these substations along with their latitude and longitude are available upon request. Nineteen years of generation profiles from 2000 to 2018 were obtained from renewables.ninja,[83] which uses weather data from NASA's MERRA reanalysis model, converted into solar power output using the Global Solar Energy Estimator (**GSEE**) model written by Stefan Pfenninger. We assume a 10% system loss, 35deg tilt and 180deg azimuth. This results in mean capacity

82 Utility-Scale Solar Forecast in Aotearoa New Zealand (mbie.govt.nz).
83 Renewables.ninja

factors (across scenarios) ranging from 13% to 18% in the South Island and 16% to 18% in the North Island.

2.3.8.8 Batteries

Assumption

175. We assume the maximum output power of any single candidate project is 60 MW. The candidate battery projects fall into two categories:

    a. 4-hour storage duration (240 MWh)

    b. 8-hour storage duration (480 MWh).

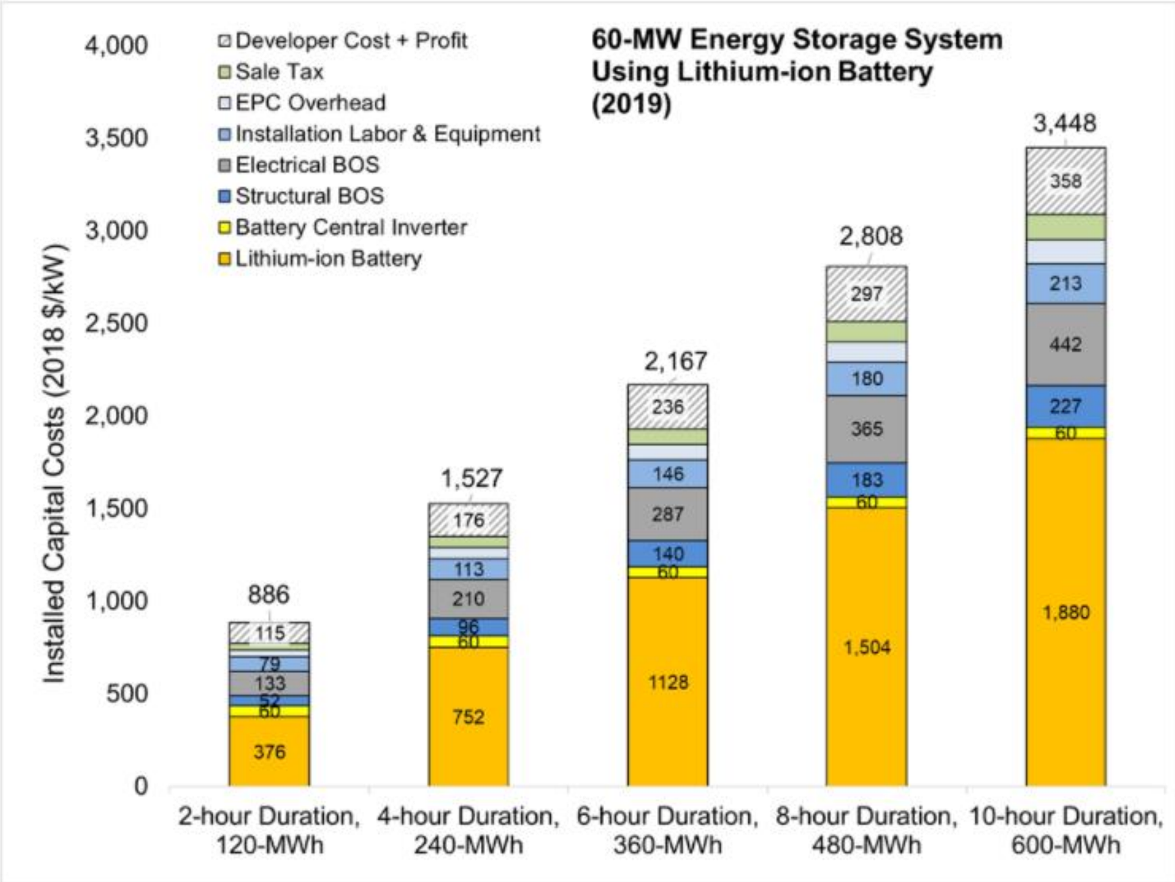
176. The round-trip efficiency of the batteries is 85%, split equally between charge and discharge. efficiency.

177. We assume candidate battery projects exist throughout the grid back-bone. Each location has both an 8-hour and a 4-hour candidate project.

North Island	South Island
SWN220	ISL220
PAK220	INV220
BHL220	BEN220
OTA220	AVI220
TAK220	CYD220
DRY220	ROX220
HLY220	SDN220
OHW220	GOR220
HAM220	CUL220
WKM220	KIK220
ATI220	
OHK220	
ARA220	
WRK220	
THI220	

TKU220A	
TMN220	
SFD220	
RPO220	
TNG220	
BRK220	
BPE220	
LTN220	
PRM220	
HAY220	
WIL220	

178. We assume the following capital costs for the batteries (shown in USD). FOM is assumed at 2.5% of the capital costs in dollars per kilowatt.



60-MW Energy Storage System
Using Lithium-ion Battery
(2019)
Developer Cost + Profit
Sale Tax
EPC Overhead
Installation Labor & Equipment
Electrical BOS
Structural BOS
Battery Central Inverter
Lithium-ion Battery
Installed Capital Costs (2018 $/kW)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
886
115
79
133
52
60
376
1,527
176
113
210
96
60
752
2,167
236
146
287
140
60
1128
2,808
297
180
365
183
60
1,504
3,448
358
213
442
227
60
1,880
2-hour Duration, 120-MWh
4-hour Duration, 240-MWh
6-hour Duration, 360-MWh
8-hour Duration, 480-MWh
10-hour Duration, 600-MWh

Background

179. We chose these battery sizes because:

   a. the four-hour battery is the benchmark battery size used by the National Renewable Energy Laboratory (**NREL**)[84]

   b. the eight-hour battery represents longer term storage that is becoming more prevalent in the industry[85]

   c. round-trip efficiencies are based on NREL's Cost Projections for Utility-Scale Battery Storage.[86]

180. The capital and operating cost estimates for these batteries are based on a study of lithium-ion batteries by NREL.[87] Although various alternative storage technologies are emerging, the cost of these alternatives is not presently well understood or characterized. We converted these to NZD at an exchange rate of 0.7 NZD:USD, based on RBNZ's average monthly exchange rate[88] over 2016 to 2020, rounded to the nearest 0.10 NZD/USD. The analysis covered 2-, 4-, 6-, 8-, and 10-hour storage durations. However, for simplicity, we only consider 4- and 8-hour as candidate projects.

2.3.8.9 Chronological cost assumptions

Assumption

181. We apply different cost decline scenarios in each market scenario to wind, solar, geothermal, and grid-scale batteries:

   a. Disruptive: advanced cost decline

   b. Environmental: moderate

   c. Growth: moderate

   d. Reference: moderate

   e. Global: conservative.

182. These cost declines (in real-terms) apply to the capital costs in sections 2.3.8.3 to 2.3.8.8 (which are specified in 2021 dollars). The scenarios are defined for each generation technology:

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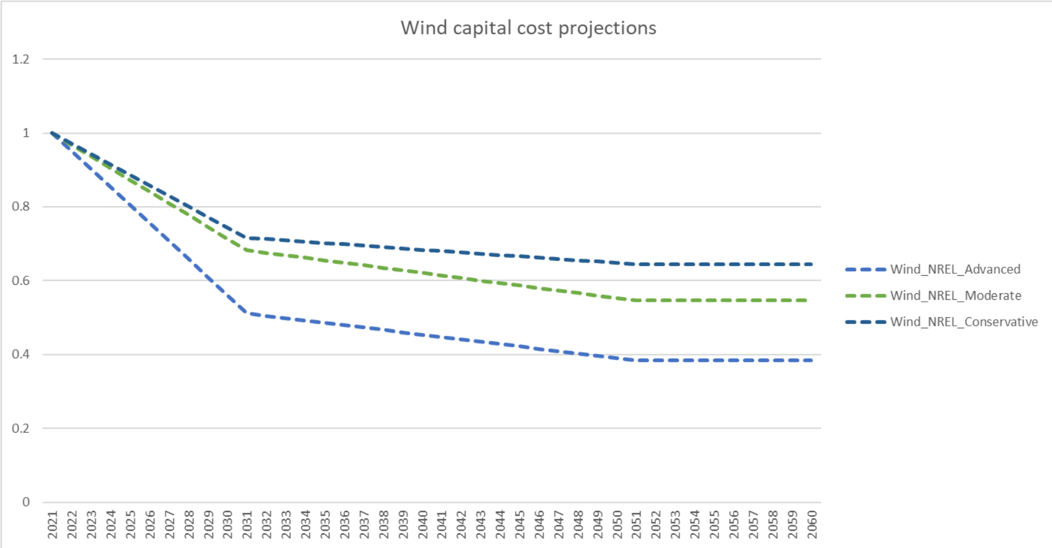
84 Cost Projections for Utility-Scale Battery Storage: 2021 Update (nrel.gov)

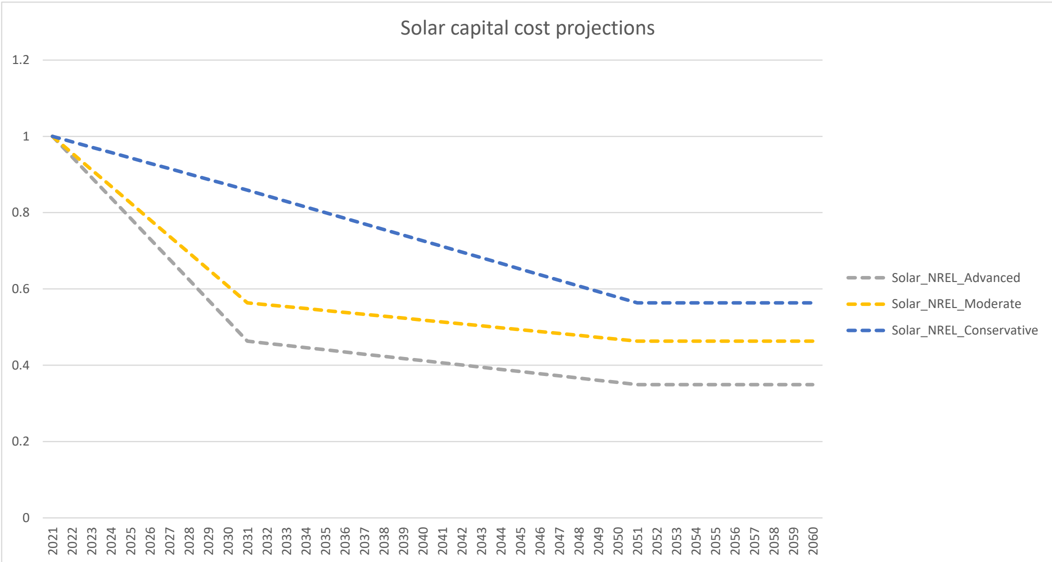
85 For example, Eight-hour lithium-ion project wins in California long-duration energy storage procurement - Energy Storage News (energy-storage.news)

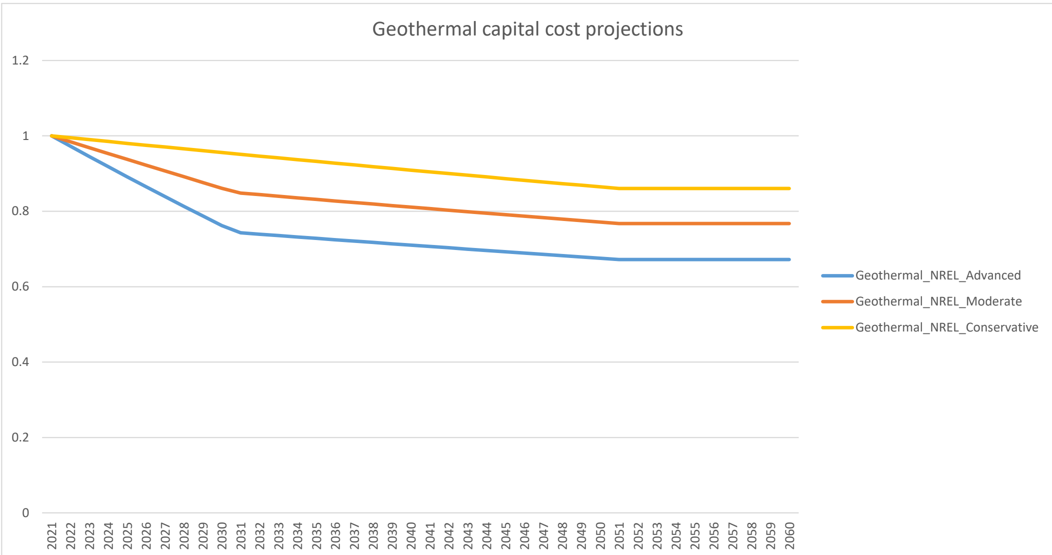
86 Cost Projections for Utility-Scale Battery Storage: 2021 Update (nrel.gov)

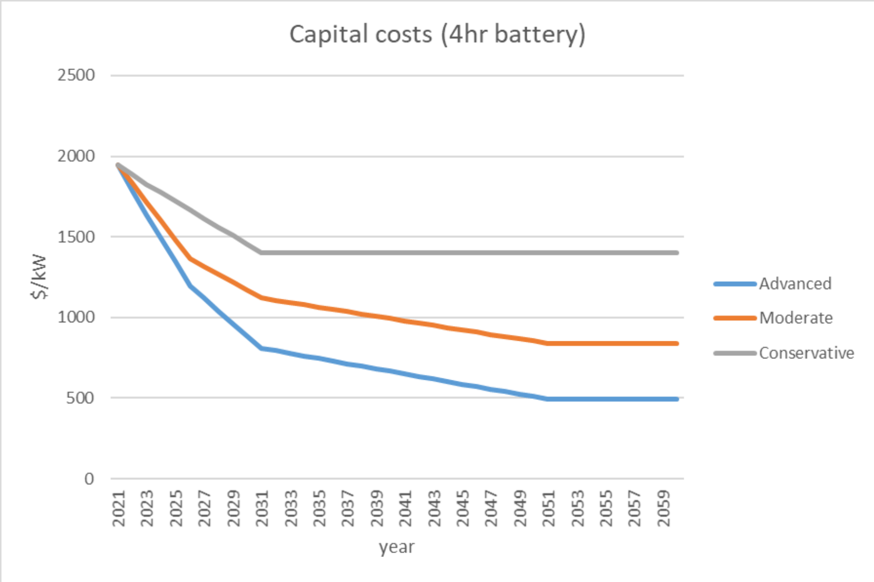
87 Utility-Scale Battery Storage | Electricity | 2021 | ATB | NREL

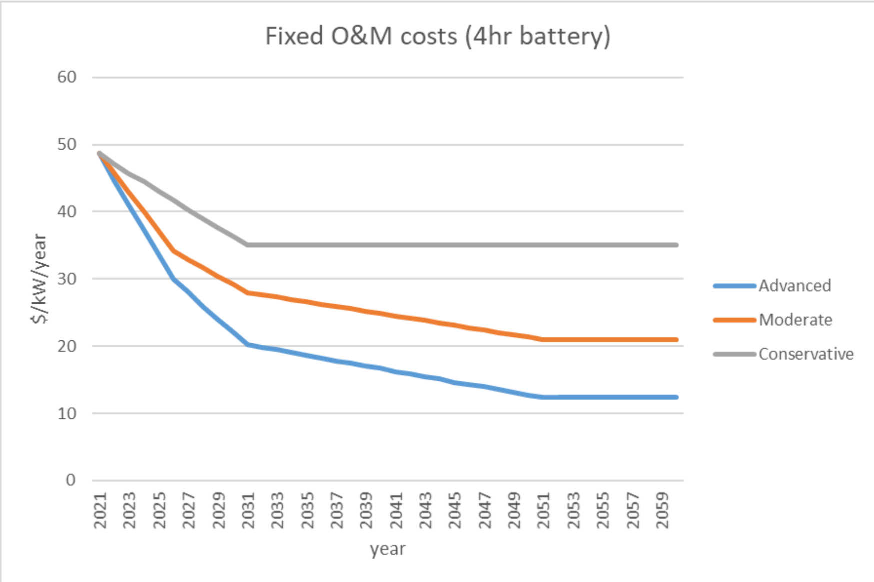
88 Exchange rate - Reserve Bank of New Zealand (rbnz.govt.nz)

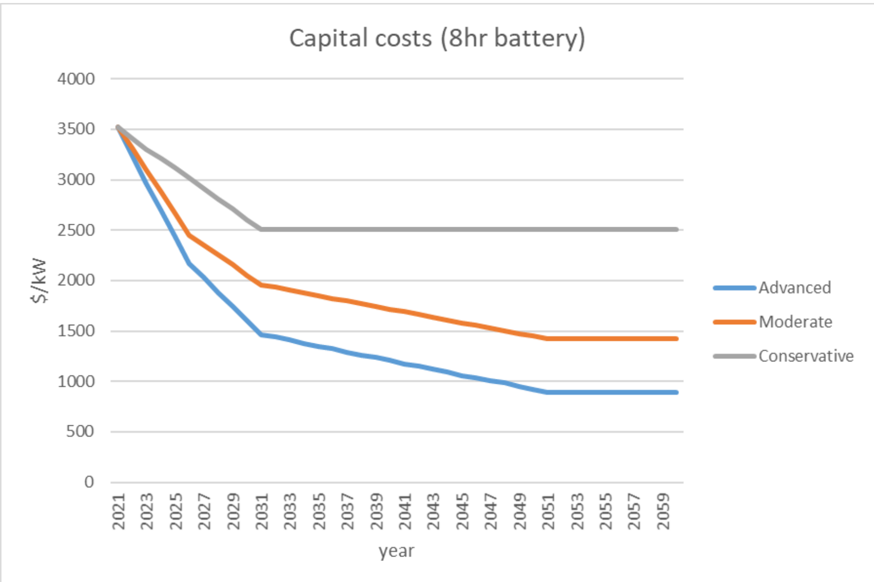

Wind capital cost projections
1.2
1
0.8
0.6
0.4
0.2
0
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056 2057 2058 2059 2060
Wind_NREL_Advanced
Wind_NREL_Moderate
Wind_NREL_Conservative


Solar capital cost projections
1.2
1
0.8
0.6
0.4
0.2
0
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056 2057 2058 2059 2060
Solar_NREL_Advanced
Solar_NREL_Moderate
Solar_NREL_Conservative


Geothermal capital cost projections
1.2
1
0.8
0.6
0.4
0.2
0
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056 2057 2058 2059 2060
Geothermal_NREL_Advanced
Geothermal_NREL_Moderate
Geothermal_NREL_Conservative


Capital costs (4hr battery)
2500
2000
1500
1000
500
0
$/kW
2021
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
2047
2049
2051
2053
2055
2057
2059
year
Advanced
Moderate
Conservative


Fixed O&M costs (4hr battery)
60
50
40
30
20
10
0
$/kW/year
2021
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
2047
2049
2051
2053
2055
2057
2059
year
Advanced
Moderate
Conservative


Capital costs (8hr battery)
4000
3500
3000
2500
2000
1500
1000
500
0
$/kW
2021
2023
2025
2027
2029
2031
2033
2035
2037
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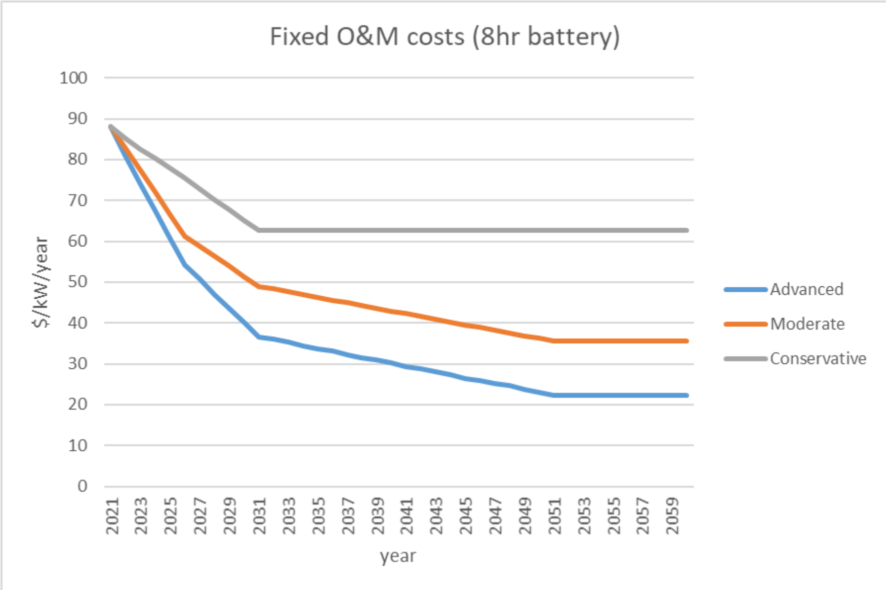
year
Advanced
Moderate
Conservative



Background

183. A generation project's capital and operating costs can change over time (in real terms). This is particularly relevant in the case of non-traditional generation such as wind, solar, and batteries, and to a lesser extent, geothermal. These technologies have seen dramatic price reductions over recent decades. This is expected to continue as research and manufacturing processes further develop and mature. Hydro and thermal generation costs are not adjusted over time because they are mature technologies that are not generally viewed as having an expanding role in overseas markets (and therefore are not expected to benefit from economies of scale and new innovations). We apply cost declines to solar, wind, batteries, and geothermal stations depending on the year in which they are built.

184. We use the cost decline scenarios from the 2021 Annual Technology Baseline (**ATB**) produced by NREL,[89] rescaled to apply to a New Zealand context.

185. Ideally, our preferred approach would be to use data directly from MBIE's generation stack reports.[90] However, there are several difficulties associated with this:

    a. for the wind costs, the levelized cost of energy (**LCOE**) specified in the wind generation stack is not a model input. We would need to make assumptions about how the individual components of LCOE (capacity factor, capital cost, fixed or variable maintenance cost, etc.) are changing to reproduce the IRENA – High and IRENA – Low scenarios

    b. there are no estimates for battery costs or geothermal stations

    c. the cost decline scenarios are not necessarily consistent between technologies as each stack report has a different author.

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89 Accessed from: https://data.openei.org/submissions/4129.

90 New Zealand generation stack updates | Ministry of Business, Innovation & Employment (mbie.govt.nz).

186. To the extent possible, we have compared the results of the ATB (rescaled to apply to a New Zealand context) with the MBIE's generation stack reports and consider that the results agree to within a reasonable tolerance of difference (see figures below).

187. There are other advantages of using the ATB, for example:

a. the numbers are published

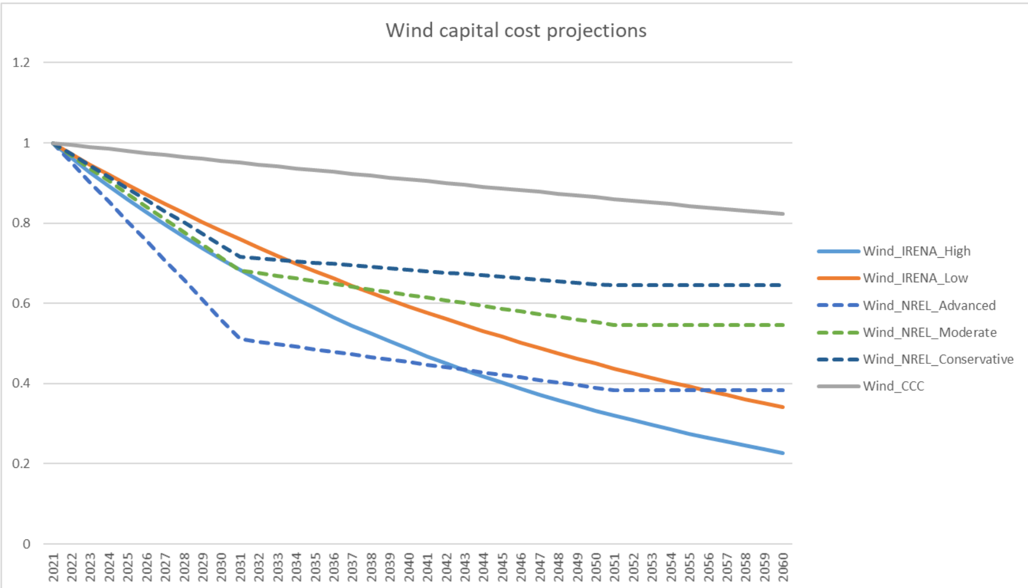
b. the numbers are updated annually

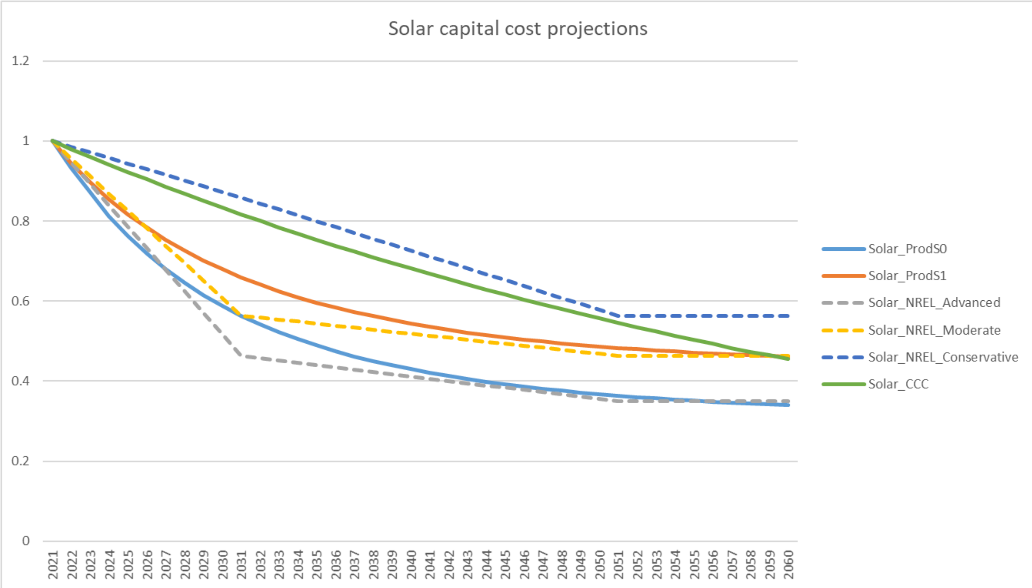
c. a consistent methodology is guaranteed across all technologies (reducing the possibility of technology bias)

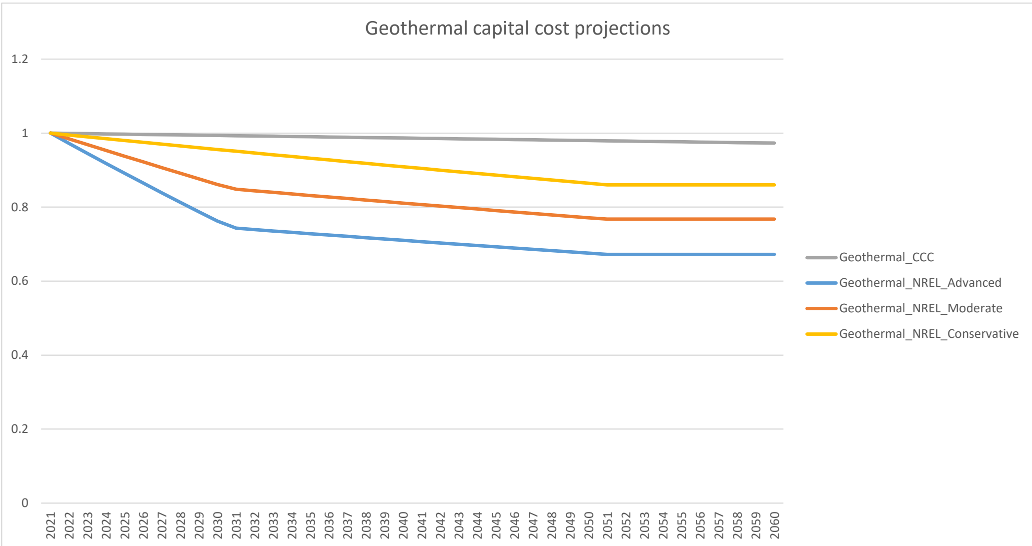
d. the estimates include battery costs

e. the ATB data is complete in that it covers all model inputs (capacity factors, capital costs, fixed and variable O&M, etc.).

188. Given these advantages and that ATB data is in reasonable agreement with the generation stack and other sources, we have decided to the use the ATB.







2.3.8.10 Placeholder generators

Assumption

189. 0.1 MW capacity diesel (representing thermal generation), wind, solar, and battery generators may be added to the factual and counterfactual to allow for future regional customer groups to be created.

Background

190. When new large generating plant is connected to the grid it will receive charges for existing BBIs based on Part F of the TPM, which requires that, for a given BBI, new customers or new large plant are assigned to the regional customer group that the new customer is expected to be a member of. The regional customer group may be a future regional customer group which has no members when allocations are first set, but are created because the benefits or disbenefits of the group are expected to be materially different to existing customers in the same modelled region.

191. Modelling placeholder generators allows us to create these future regional customer groups where:

   a. the benefits or disbenefits to a generation technology that doesn't currently exist in a modelled region may be materially different to existing generators in that modelled region; and

   b. OptGen has not commissioned all the possible generation technologies in a given modelled region.

192. The placeholder generators will have a 0.1 MW capacity such that they don't materially impact the modelled dispatch and prices.

193. We will not implement placeholder hydro generators because we consider the existing hydro generation is sufficiently dispersed that there will be a group for any new hydro generation to join. Similarly, we will not implement placeholder geothermal generation because any new generation is likely to connect in the regions where existing geothermal generators are located and so will have a group to join.

2.3.8.11 Firm capacity constraint

Assumption

194. We use a firm capacity constraint within the model. We assume a 5% capacity margin. We assume the following firm capacity certificates for each generation technology.

Generation technology	Firm capacity certificate
Wind	5%
Solar	0%
Thermal (gas, geothermal coal, cogen, biofuel)	100%
Hydro	100%
Battery	100%

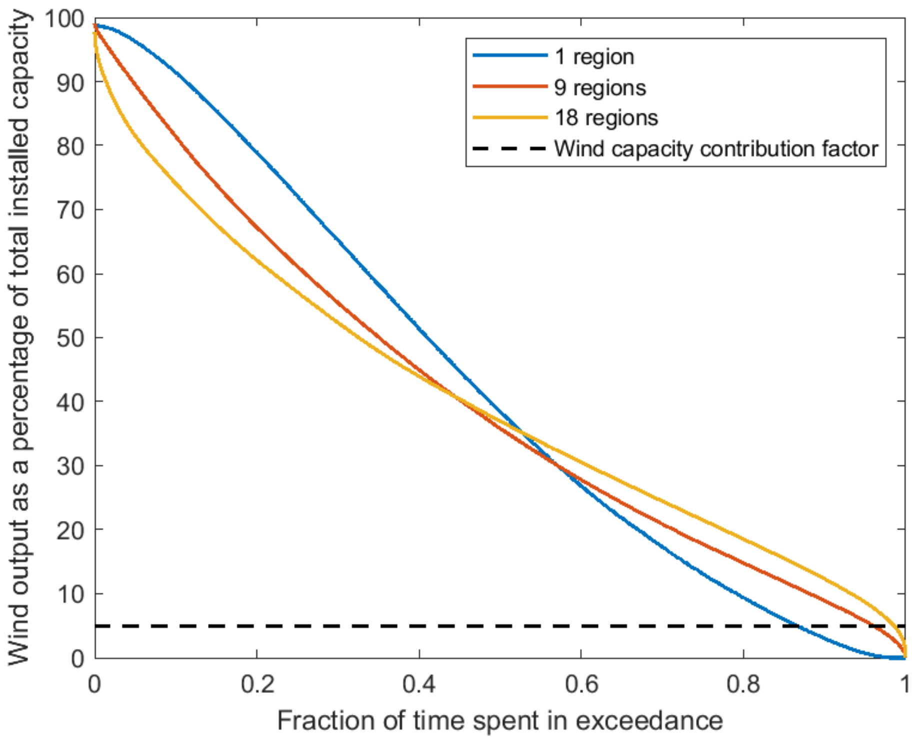
Background

195. A firm capacity constraint is needed due to the increasing proportion of intermittent wind and solar within the new generation build and the known issues around these technologies being able to meet peak demand. To achieve statistical significance in the dispatch during peak demand periods would require a larger number of renewable resource scenarios than what is practicable. A firm capacity constraint mitigates against this limitation as it forces a certain minimum level of dispatchable (or otherwise reliable) generation to exist on the system. We tested a 5% and 10% capacity margin. The 10% margin resulted in an excessive amount of additional capital cost which we considered unrealistic and therefore we decided to use the 5% margin. The firm capacity constraint is given by:

$$(1 + capacity\ margin) \times (Peak\ demand) \leq \sum_{plant} (firm\ capacity\ certificate)_{plant} \times (nominal\ capacity)_{plant}$$

196. We assume a firm capacity certificate of zero for solar because peak demand usually occurs on a winter evening when no solar generation can contribute.

197. We assume a firm capacity certificate of 5% for wind. This value reflects the capacity that would be available approximately 98.5% of the time (according to our renewable resource profile data and assuming the wind farms have sufficient regional diversity). This is illustrated in the figure below.



198. We assume a firm capacity certificate of 100% for batteries, thermal, and hydro generation because we generally expect dispatchable resources to be available during peak demand.

Chapter 3
Processes and methodologies for the standard methods and simple method

3.1 Introduction to this chapter

3.1.1 Purpose

199. This chapter provides an explanation of the processes and methodologies Transpower applies to calculate starting BBI customer allocations for post-2019 BBIs.

3.1.2 Background

200. The costs of new and certain historic interconnection investments (BBIs) are allocated to benefitting customers through BBCs. BBIs include investments in new interconnection assets and the replacement or refurbishment of existing ones.

201. The cost recovered through the BBCs for a BBI is referred to as the BBI's covered cost and includes the BBI's capital components (return of and on capital expenditure) and an allocation of Transpower's total operating costs (including overheads). See clauses 39 and 40 for more detail on the calculation of covered cost.

202. A BBI's covered cost is allocated between customers so that the allocation is broadly proportionate to the expected positive net private benefit (**EPNPB**) each customer derives from the BBI.[91] That is, the BBC paid by a customer must reflect that customer's EPNPB from the BBI (if any) relative to all other customers' EPNPB.

3.1.3 Starting BBI customer allocations for new (post-2019) BBIs - standard and simple methods

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

204. The two standard methods are used to calculate EPNPB and starting BBI customer allocations for post-2019 BBIs expected to be valued over \$20m when fully commissioned (high-value BBIs). The simple method is used to calculate EPNPB and starting BBI customer allocations for post-2019 BBIs valued up to \$20m (low-value BBIs). This aligns with the \$20m base capex threshold set by the Commerce Commission (**Commission**), below which Transpower does not need to seek separate Commission approval for grid investments.

205. The following diagram illustrates how Transpower determines which method to apply to a post-2019 BBI.

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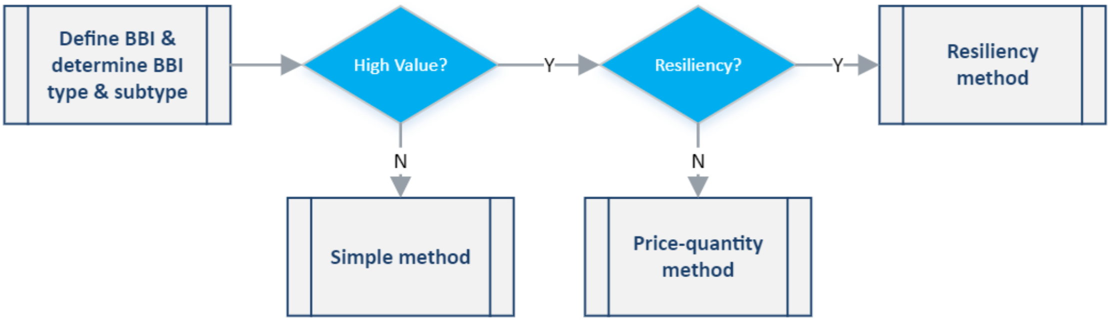
91 Where we refer to expected positive NPB, this is consistent with the TPM, which defines NPB as the sum of quantified benefits (positive values) and disbenefits (negative values) the regional customer group or customer is expected to receive from the relevant BBI. We use the term "expected" in this paper to signal that when we set customer allocations we do so based on customers' expected positive NPB at the time of setting. Unless there is an adjustment event (Part F of the TPM), customer allocations are not updated for a customer's actual NPB (or their expected NPB) in later periods even if these change.



Determine method for post-2019 BBI

3.1.4 The standard methods - price-quantity method and resiliency method

206. 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. Section 3.3 of this chapter relates to the price-quantity method.

207. The resiliency method must be used where the primary purpose of a high-value post-2019 BBI is to mitigate a risk of cascade failure or a high impact, low probability (**HILP**) event resulting in unserved energy (referred to as a resiliency BBI). Section 3.4 of this chapter relates to the resiliency method.

208. Both standard methods involve determining regional customer groups of beneficiary customers (and, under the price-quantity method, the regional net private benefit (NPB) for each regional customer group) and then calculating individual NPBs for the customers in those groups with positive regional NPB based on historical grid use, mostly grid offtake or injection. The individual NPBs are then used to calculate the starting BBI customer allocations for the relevant BBI.

3.1.5 The simple method

209. The simple method uses a regional allocation model with regional allocation factors for generation and load to calculate regional NPB for each regional customer group. The regions and regional allocation factors are static – they apply to all low-value BBIs commissioned during a (usually) five-year simple method period, after which the regions and regional allocation factors are reset for low-value BBIs commissioned in the next simple method period (the BBI customer allocations for previously commissioned low-value BBIs do not change). The regions and regional allocation factors are calculated based on historical power flows before the start of the simple method period.

210. Under the simple method, as under the standard methods, individual NPBs for the customers in the regional customer groups with positive regional NPB are calculated based on historical grid use (grid offtake or injection), and the individual NPBs are then used to calculate the starting BBI customer allocations for the relevant BBI. Section 3.5 of this chapter relates to the simple method.

3.2 Define BBI and determine BBI type and sub-type

211. Internally, we often group expenditure together into a project or programme for administrative purposes (e.g. a tower painting programme made up of many small projects). However, under the TPM, we need to determine if a project or programme is a single BBI or several BBIs.

212. The Transpower Capex Input Methodology (**Transpower Capex IM**) includes definitions of project and programme for the purpose of determining if expenditure exceeds the base capex threshold:[92]

> ***project*** *means temporary endeavour requiring concerted effort, which is undertaken to create defined outcomes*
>
> ***programme*** *means-*
>
> *(a) 2 or more projects; or*
>
> *(b) 2 or more projects and expenditure activities,*
>
> *within the same category of capital expenditure that are grouped together on the basis of having a common purpose.*

213. Based on these definitions, we typically consider expenditure to be a single project or programme if it meets a common investment need.

214. For example, under the Transpower Capex IM, capital expenditure incurred to maintain the HVDC link is typically grouped together because all of the expenditure works together to ensure the HVDC link continues to operate. However, a tower painting programme consisting of many towers throughout the country would typically not be grouped together because the lines are in different geographic areas of the network.

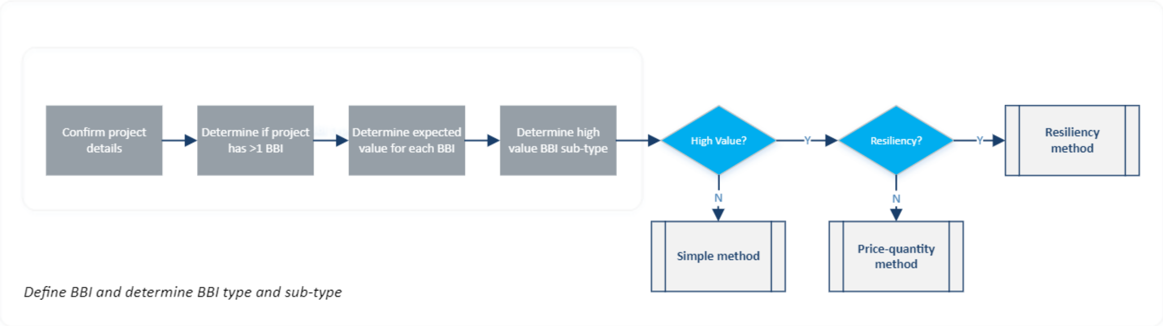
215. While this principle (or similar) is sufficient for the purpose of applying the Transpower Capex IM, it is not necessarily sufficient when determining if expenditure should be grouped together into a BBI under the TPM.

216. Defining the BBI is a pre-requisite to determining the method used to allocate BBCs for the BBI. We need to know:

    a. the type of the BBI, i.e. whether it is high-value or low-value (see paragraphs 221 to 224)

    b. if the BBI is a high-value, the sub-type, i.e. whether it is a resiliency BBI or not (see paragraphs 225 to 227).

92 Transpower-capital-expenditure-input-methodology-determination-consolidated-29-January-2020.pdf (comcom.govt.nz).



217. Paragraphs 218 to 229 provide a description of each process.

3.2.1 Confirm project details

218. When we propose a project (or programme) to the Commission (or as part of Transpower's internal business case approval process if not a tested investment[93]), the following will be confirmed:

a. the expected capital expenditure and, if the project includes a transmission alternative, operating expenditure of the project

b. the benefit types (i.e. market, reliability, ancillary service, resiliency and/or other benefits) that are expected to result from the project

c. the expected commissioning date of the project, including where different stages (that is, specific grid outputs) of the project will be commissioned at different dates.

3.2.2 Determine if project has >1 BBI

219. It may be necessary for us to break a project (or programme) into more than one BBI in order to produce starting BBI customer allocations that are broadly proportionate to EPNPB. These are some situations where we may split a project into multiple BBIs:

a. programmes of asset replacement or refurbishment relating to assets in very different parts of the network (e.g. a tower painting programme)

b. when project components are committed at significantly different times. For example, the Lower South Island (**LSI**) Renewables project was originally approved in 2010 but was committed and has been delivered as two distinct projects – the first stage was completed in 2015/16 and the second will be substantially completed in 2022

c. where a project consists of distinct groups of grid outputs that address different investment needs.

220. This step also confirms the final grid state that will be delivered via the BBI and, as such, used as the factual under a standard method if the BBI is high-value.

[93] We refer here to the investment test applied to a tested investment under section III of Part F of the old Electricity Governance Rules or the Transpower Capex IM.

3.2.3 Determine expected value for each BBI

221. Once the project (or programme) has been assigned to one or more BBIs, the expected asset value and transmission alternative operating expenditure for the fully commissioned BBI can be confirmed.[94]

222. Where the expected value for a fully commissioned BBI is ≤$20m (that is, the BBI is a low value BBI), the TPM requires us to use the simple method in order to calculate a customer's individual NPB for that BBI. Similarly, if a project or programme is comprised of multiple BBIs whose individual value is <$20m but combined value is >$20m, the simple method will be applied.

223. All high value BBIs (those with an expected value when fully commissioned that exceeds $20m) will use either the resiliency or price-quantity method to calculate a customer's individual NPB.

224. The fully commissioned value of a BBI will be assessed based on the Commission-approved major capex allowance and/or maximum recoverable costs for the BBI, where available.

3.2.4 Determine high-value BBI sub-type

225. We will determine if a high-value post-2019 BBI is under the price-quantity or resiliency method based on the primary investment need being met by the BBI.

226. The resiliency method will be used when we determine that the primary investment need being met by the BBI relates to mitigating the risk of a HILP event or cascade failure. In all other instances we will use the price-quantity method.

227. For the purposes of the TPM, we consider a HILP event to be an event (or group of events) with the following characteristics:

    a. the probability of its occurrence is less than or equal to a 1 in 30-year event, and

    b. the impact of the event would be unserved energy greater than 2 GWh (but is not cascade failure).

3.2.5 Expenditure on existing BBIs

228. The discussion above is about expenditure that is comprised in a new BBI.

229. Under clause 37 of the TPM we may decide to treat refurbishment and replacement investments as part of an existing BBI, subject to certain limits. If we do that the investment will increase the covered cost of the existing BBI and we will not need to determine whether to treat the investment as one or more new BBIs.

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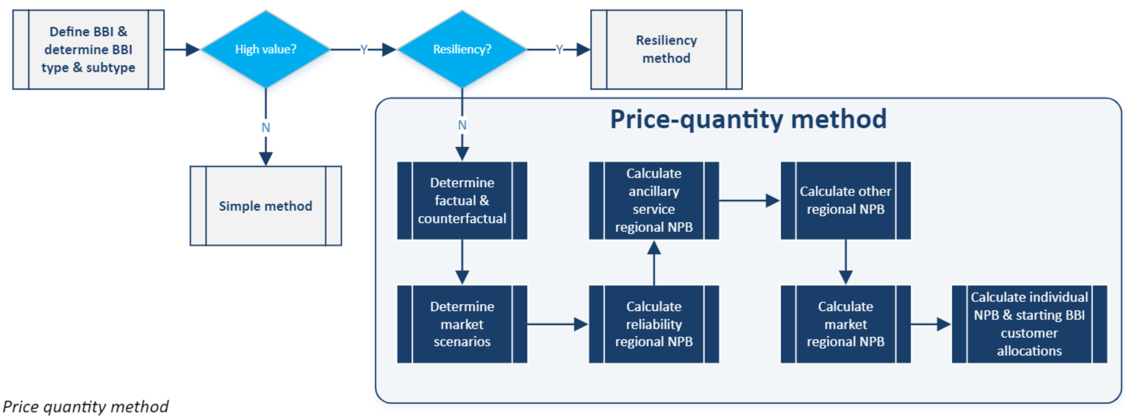
94 Like the test against the base capex threshold in the Capex IM, the high-value/low-value test in the TPM is on the expectation (forecast) of the project's cost, not the actual cost after commissioning. If a BBI's expected value when fully commissioned is less than the base capex threshold, it will be under the simple method regardless of its actual value after full commissioning.

3.3 The price-quantity method (standard method)

230. The price-quantity method is used to calculate EPNPB when we determine that a high-value post-2019 BBI has not met the criteria of a resiliency BBI.

231. The price-quantity method requires a series of processes to be performed, as illustrated in the diagram below.



Price quantity method

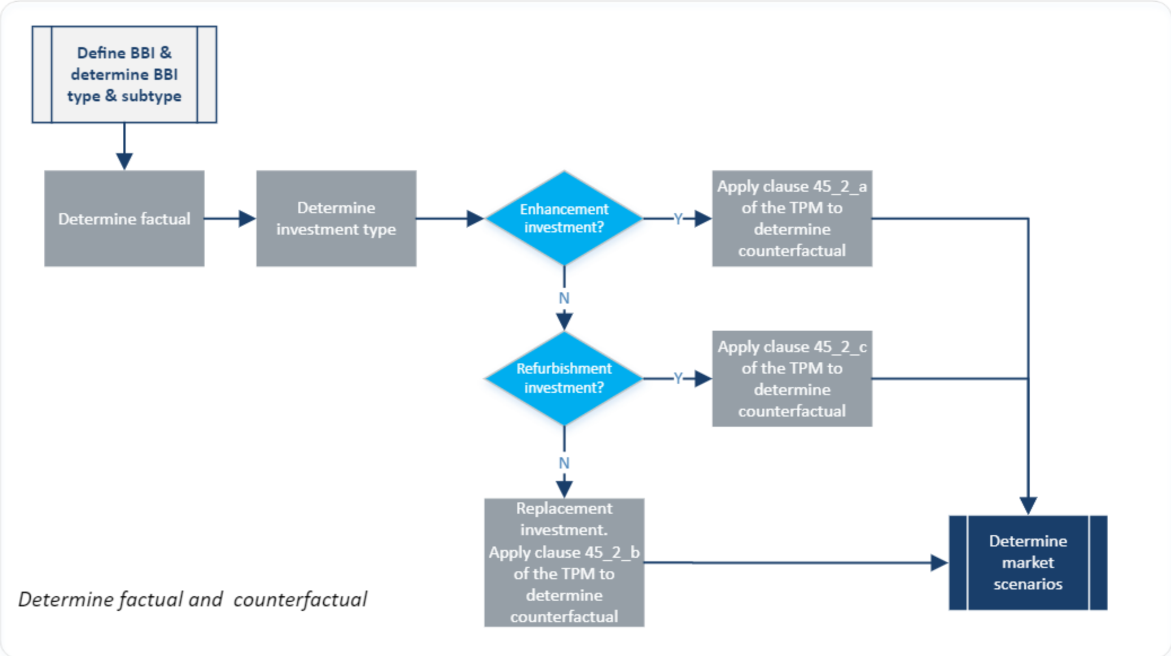
232. Sections 3.3.1 to 0 provide a description of each process.

3.3.1 Determine factual and counterfactual

3.3.1.1 Introduction

233. The price-quantity method requires us to determine the factual and counterfactual (the future state of the grid with and without the BBI). This section provides a summary of the process undertaken to reach this determination and why it is necessary.

3.3.1.2 Overview diagram



3.3.1.3 Determine factual

234. The factual is the expected future grid state that will result from the completion of the BBI (i.e. the BBI is fully commissioned).

3.3.1.4 Determine investment type (and counterfactual)

235. The counterfactual is the expected future grid state that would result should no part of the BBI be completed (i.e. the BBI is not commissioned). In order to determine the counterfactual, we must determine the type of investment(s) being completed. Investments can be one of the following three types, and may also be a compliance investment:[95]

   a. replacement

   b. refurbishment

   c. enhancement.

236. The definitions of each investment type are specified in the TPM and are based on definitions in the Transpower Capex IM. Clause 45 states the principles we must use for determining the counterfactual depending on the investment type.

237. Occasionally, a BBI may be a combination of these investment types, e.g. an investment that increases the capability of the grid today (an enhancement) and also an investment to replace an asset nearing the end of its life (a replacement). In such situations, we will combine the clause 45 principles when determining the counterfactual in order to ensure the counterfactual represents a reasonably likely future grid state.

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95 A compliance investment is an investment made to ensure the grid can be operated within accordance with good electricity industry practice. A compliance investment may also be an enhancement, refurbishment or replacement investment.

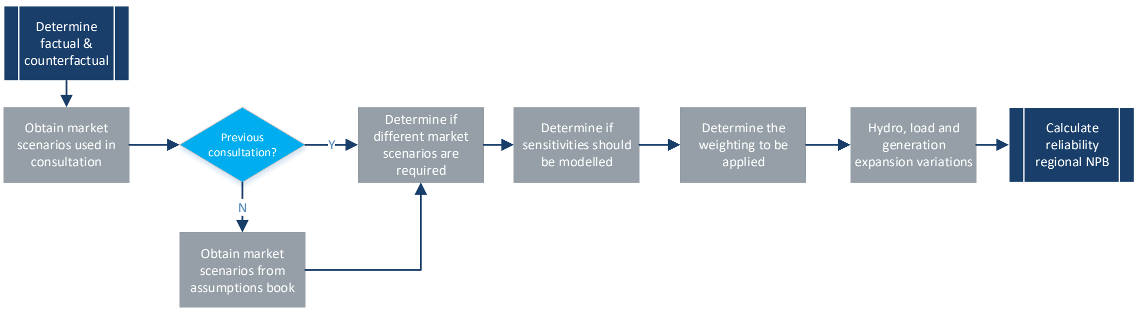
3.3.2 Determine market scenarios

3.3.2.1 Introduction

238. The price-quantity method requires us to determine market scenarios.[96] This section provides a summary of the process undertaken to reach this determination.

239. Clause 43(5) requires the input assumptions (including market scenarios) used to apply the standard method to be as consistent as reasonably practicable with those used to apply the investment test, except where we determine they would not produce allocations that are broadly proportionate to EPNPB (and as otherwise stated in the TPM). Therefore, the philosophy of this step is to use the same market scenarios as used for the investment decision. However, due to the different requirements of the TPM and the Transpower Capex IM, the market scenarios used for calculating EPNPB may need to be different, as outlined in this section.

3.3.2.2 Overview diagram



Determine market scenarios

3.3.2.3 Obtain market scenarios used in consultation

240. We may have consulted on the market scenarios for the BBI as part of investment test consultation under the Transpower Capex IM (or under the old Electricity Governance Rules). Our starting position is that we will use the same market scenarios for the price-quantity method.

241. However, the TPM does not require that this be the case where we determine that the application of the investment test market scenarios will not produce starting BBI customer allocations that are broadly proportionate to EPNPB. This may occur because:

    a. the investment test assesses efficiency net benefit, not private benefits, or

    b. the investment test is a decision-making tool, not a precise forecast of net benefits, whereas the price-quantity method requires us to calculate individual NPB for each beneficiary customer.

242. In these instances, we will change, add, or remove market scenarios (see section 3.3.2.5).

96 "Scenarios" in the TPM also includes outage scenarios, which are used for calculating regional reliability NPB. Section 3.3.3.4 details the process we use to determine an outage scenario.

3.3.2.4 Obtain market scenarios from the assumption book

243. When we have not previously consulted on the market scenarios for the BBI for the purpose of complying with the Transpower Capex IM (or old Electricity Governance Rules), our starting position is that we will use the market scenarios in chapter 2 of this assumptions book.

244. However, we may depart from the market scenarios in this assumptions book for the same reason we may depart from investment test market scenarios, i.e. we determine it is necessary to do so to calculate starting BBI customer allocations that are broadly proportionate to EPNPB (see section 3.3.2.5).

3.3.2.5 Determine if different market scenarios are required

245. We may apply different market scenarios to those used to comply with the Transpower Capex IM (or old Electricity Governance Rules) or those in chapter 2 of this assumptions book.

246. Examples of situations that may lead to a change in market scenarios are:

    a. to incorporate new information since the investment test was applied or the assumptions book was published

    b. to better reflect expected (i.e. probability-weighted) private benefits. For example:

        - if MBIE has included the decommissioning of a large plant in two of five EDGS[97] scenarios, but we consider it should be given an equal weighting under the price-quantity method for a given BBI, we will model an equal number of market scenarios with and without the decommissioning (e.g. five with the decommissioning and five without).

        - if a market scenario is a sensitivity rather than one of the base scenarios in the EDGS or the investment test, we may include it as a market scenario under the price-quantity method to better reflect probability-weighted private benefits (subject to section 3.3.2.6)

    c. to exclude unlikely market scenarios that were included in the investment test to test the robustness of an investment to uncertainty but are considered unlikely to occur

    d. to remove market scenarios where they do not affect starting BBI customer allocations. This may occur where EPNPB varies across market scenarios, but the proportion of EPNPB received by beneficiary customers does not materially change.

3.3.2.6 Determine if sensitivities should be modelled

247. We will consider if a discrete change in our modelling assumptions that can occur independently of other assumptions should be included in our analysis (e.g. a decommissioning of a large plant). We refer to these discrete changes as sensitivities. Where we decide to include a sensitivity, we will do so by adding at least one market scenario with the sensitivity in place but with all other assumptions the same.

248. There are likely to be several possible discrete changes in modelling assumptions that may affect EPNPB if we included them in a market scenario. However, we do not propose to model variations in all possible assumptions because:

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97 Electricity demand and generation scenarios: Scenario and results summary (mbie.govt.nz).

a. it is not practicable to model all the possible discrete changes that may occur over a 20-year standard method calculation period

b. even if we modelled every plausible change, we would need to either implicitly or explicitly assign a probability to the change.

249. We will consider the inclusion of a sensitivity to model discrete changes in modelling assumptions if it meets the following criteria:

a. the change is likely to materially affect the starting BBI customer allocations

b. we have sufficient information about the change to model it accurately (e.g. size, location, and operating characteristics)

c. the change has been discussed in the latest EDGS, in disclosure information provided to financial markets, or in other publicly available documents from reputable sources

d. the effect of the change is not already approximated in other market scenarios.

3.3.2.7 Determine the weighting to be applied

250. The market scenario weightings will be:

a. adopted from the relevant weightings used in the investment test for the BBI

b. if there is no relevant investment test weighting or the relevant investment test weighting would not produce starting BBI customer allocations broadly proportionate to EPNPB, sourced from chapter 2 of this assumptions book, or

c. if there is no relevant chapter 2 weighting or the relevant chapter 2 weighting would not produce starting BBI customer allocations broadly proportionate to EPNPB, determined by Transpower.

3.3.2.8 Hydro, load, and generation expansion variations

251. Clause 47(1) requires the market scenarios for a market BBI to include variations in load growth, generation expansion, and hydrology. Chapter 2 of this assumptions book details how we will meet this requirement for load growth and hydrology variations.

252. We will use Transpower's generation expansion tool to model how the national generation mix will change over the standard method calculation period in each market scenario.[98] In addition, for a market BBI, we will use this tool to assess if the market BBI is expected to materially influence generation development by including the modelled constraints (see section 3.3.6.4) in the generation expansion model. If it does and we consider it will result in starting BBI customer allocations that better reflect positive NPB, we may use different generation scenarios in the factual and counterfactual as permitted by clause 46(2).

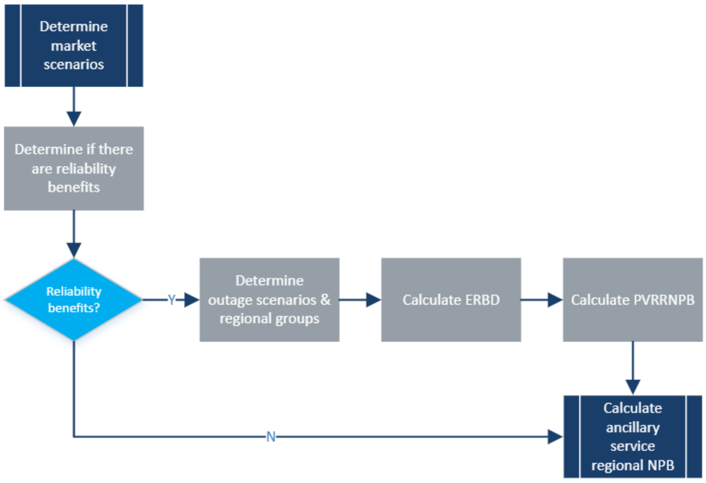
[98] A generation expansion tool produces forecasts of new generation over an analysis period based on inputs such as the transmission grid, demand, and the operating characteristics, capital, and operating costs of possible new generating stations. We currently use PSR's OptGen as our generation expansion tool.

3.3.3 Calculate reliability regional NPB

3.3.3.1 Introduction

253. The purpose of this section is to provide a summary of the process undertaken to calculate reliability regional NPB for a high-value post-2019 BBI.

3.3.3.2 Overview diagram



Calculate reliability regional NPB

3.3.3.3 Determine if there are reliability benefits

254. Reliability regional NPB may be calculated when we determine the BBI will result in a material reduction in curtailed energy (either of demand or supply) due to an outage or other event or group of events affecting access to transmission services. In this case the BBI is referred to as a reliability BBI.

255. Where a BBI affects security constraints that are managed by the system operator as pre-contingent market constraints, we will assess the BBI as a market BBI only, even if the investment is undertaken under the grid reliability standards. The calculation of reliability regional NPB is limited to situations where supply to and from the grid is interrupted due to a fault or outage.

256. A high-value post-2019 BBI has reliability benefits if it:

    a. increases the redundancy of supply to customers no more than n-2 (e.g. a new line into a region where there was previously only one),[99] or

    b. reduces the extent or duration of an interruption to supply to customers (e.g. a special protection scheme that trips some load but prevents a more widespread interruption).

---

99 N-2 refers to two levels of redundancy i.e. supply can continue after two separate components fail. We do not consider there will be material reliability benefits from a BBI that increases redundancy beyond n-2.

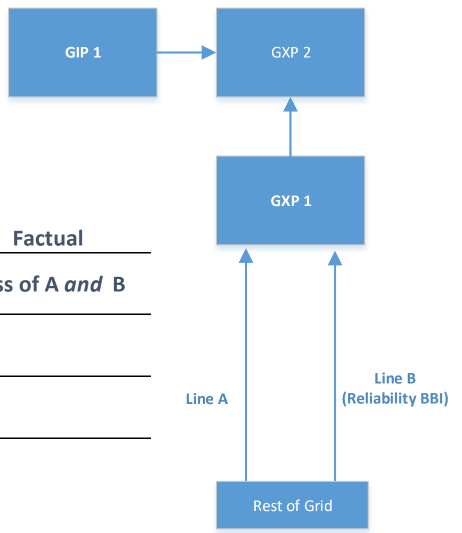
257. The exception to this is where we determine that the BBI mitigates the risk of a HILP event or cascade failure (see paragraph 227). In these instances, we will use the resiliency method to calculate EPNPB and starting BBI customer allocations (see section 3.4).

3.3.3.4 Determine outage scenarios and regional customer groups

258. To calculate the reliability regional NPB for the BBI, we need to determine the customers that will be affected by the outages or other events (the outage scenarios) the BBI is mitigating the curtailed energy risk of, and assign those customers to either a regional demand group or a regional supply group.

259. For BBIs that increase the redundancy of supply, the outage scenario will be the loss of the transmission components supplying the same GXPs/GIPs as the BBI. These will be the GXPs/GIPs where the change in expected curtailed energy is in the same direction (a reduction in expected curtailed energy). Therefore, the regional demand group will be the GXPs supplied by the BBI, and the regional supply group will be the GIPs connected to the grid via the BBI,[100] as represented in the diagram below where line B is the BBI.

	Counterfactual	Factual
Outage Scenario	Loss of A	Loss of A *and* B
Regional Demand Group	GXP 1 & 2	
Regional Supply Group	GIP 1	

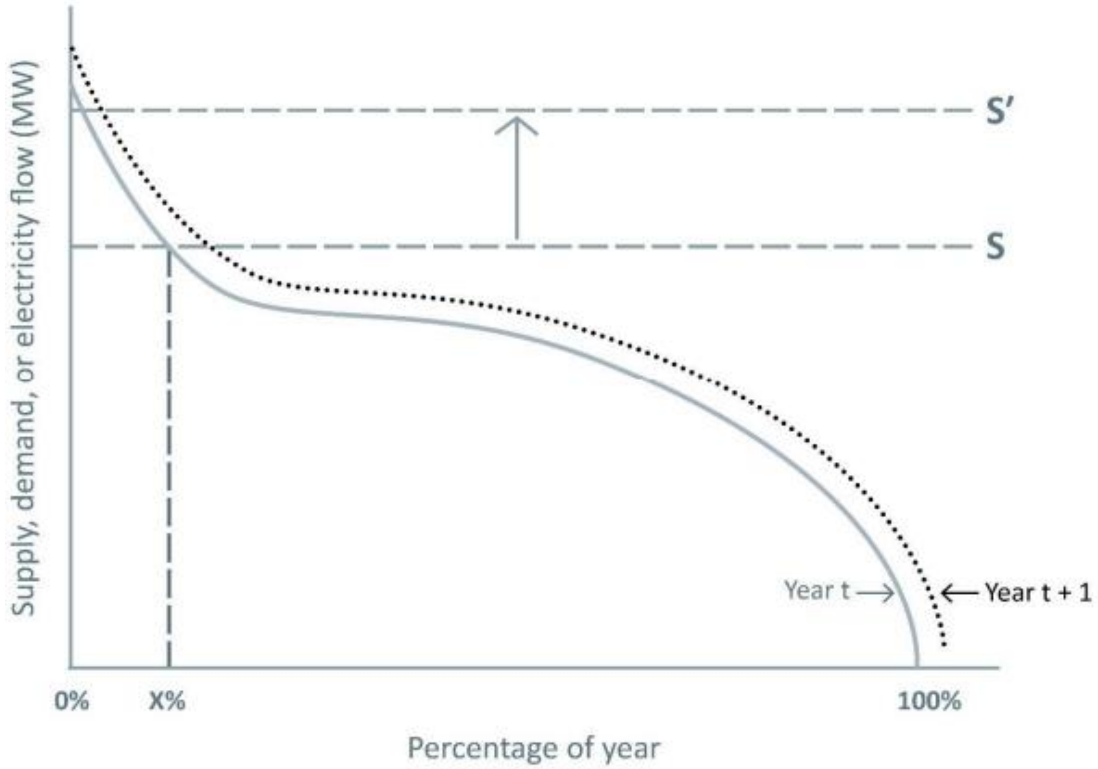


260. For reliability BBIs that reduce the duration or extent of an outage, we will determine the outage scenarios and regional customer groups on a case-by-case basis.

3.3.3.5 Calculate ERBD

261. The diagram below illustrates how we will quantify the expected reliability benefits and disbenefits (**ERBD**).

100 This example assumes the GIP cannot operate islanded from the rest of the grid, and therefore benefits from the more reliable connection to the grid.



262. The capability of the transmission system before and after investment is represented by system limits (s and s' in the diagram above). These limits represent the point above which the system is at risk of interruption following an outage scenario. System limits are produced by detailed engineering modelling of the capability of the power system.

263. The probability of being above a system limit is represented by a supply, demand, or transmission flow duration curve (depending on the nature of the outage scenario being mitigated), which is the supply, demand, or transmission flow throughout the year ordered from its highest level (i.e. the peak) to the lowest (i.e. the trough).

264. The magnitude of curtailed energy is calculated by the probability of being above the limit multiplied by the probability of the outage scenario occurring multiplied by the amount of load or generation expected to be disconnected following the outage scenario.

265. ERBD is equal to the change magnitude of curtailed energy (MWh) multiplied by the value of lost load (**VoLL**) or value of lost generation (**VoLG**) ($/MWh), where the ERBD is the magnitude of curtailed energy in the counterfactual minus the magnitude of curtailed energy in the factual (clause 54(6)).

3.3.3.6 Calculate PVRRNPB

266. There are three steps required to calculate the present value of reliability regional NPB (**PVRRNPB**), detailed in the following sections.

Remove ERBD for customers or large plant that do not currently exist

267. Before finalising ERBD for a regional customer group and outage scenario, we remove ERBD attributable to customers or large plant (≥ 10 MW) that do not currently exist.[101] We do this in proportion to the size of the load relative to the size of the node. For example, if a regional customer group's ERBD is $100m, the regional customer group's annual demand is 500 GWh, and the size of the new customer or large plant is 50 GWh, the regional customer group's ERBD will be $90m. By removing these benefits or disbenefits, we allow individual NPB to be calculated correctly under clause 83 when the new customer or large plant connects to the grid.

Calculate PVRRNPB

268. PVRRNPB is calculated as the weighted average value of ERBD for each regional customer group and market scenario (clause 54(7)). We also apply the discount rate (the BBI's standard method rate) to the RRNPB at this step.

$$PVRRNPB = \frac{1}{\sum W_s} \sum_s \sum_t \frac{ERBD_{t,s}}{(1+discount\ rate)^t} \times W_s$$

where W_s is the probability weighting for the market scenario.

269. In accordance with clause 46(3), if a market scenario for a BBI includes a customer ceasing to be a customer, the market scenario will not be applied in the BBIs factual or counterfactual in respect of that customer (i.e. will have a weighting of zero).

Remove regional customer groups with a negative PVRRNPB

270. Clause 47 requires that a customer's individual NPB only be calculated in respect of their regional customer groups with positive present values of regional NPB. As a consequence, regional customer groups with negative present values of reliability regional NPB are excluded from the calculations of individual NPB and starting BBI customer allocations.

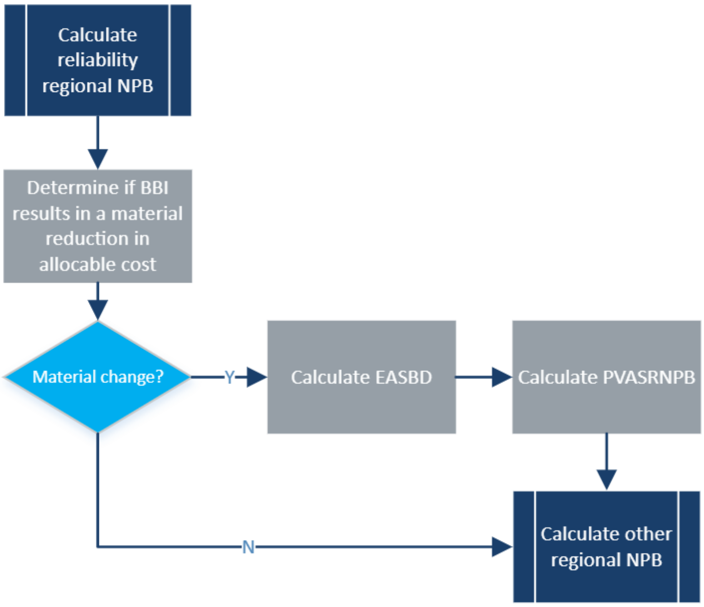
3.3.4 Calculate ancillary service regional NPB

3.3.4.1 Introduction

271. The purpose of this section is to provide a summary of the process undertaken to calculate ancillary service regional NPB for a high-value post-2019 BBI.

[101] Except if the group is a future regional customer group, in which case we need to retain the regional NPB for that group in order to calculate the individual NPB for customers entering the group when they connect to the grid.

3.3.4.2 Overview diagram



Calculate ancillary service regional NPB

3.3.4.3 Determine if BBI results in a material reduction in allocable cost

272. We may calculate ancillary service regional NPB where we determine the BBI will result in a material decrease in the allocable cost of any of three specified ancillary services – instantaneous reserve, frequency keeping and/or voltage support. In this case the BBI is referred to as an ancillary service BBI.

273. Under the TPM, only direct allocations of allocable cost to customers are relevant. Allocations to Transpower are ignored. This is why no EPNPB is calculated for over frequency reserve or back start, all of the allocable cost of which go directly to Transpower. Transpower's allocation of the allocable cost for instantaneous reserve is also ignored.

274. The allocable cost of instantaneous reserve (absent event charges) is paid by owners of generating units greater than 60 MW capacity and the HVDC owner (Transpower). We may calculate ancillary service regional NPB in respect of instantaneous reserve where we expect this allocable cost to materially decrease as the result of the BBI.

275. The allocable cost of frequency keeping is paid by purchasers of electricity in proportion to their share of grid offtake. We may calculate ancillary service regional NPB in respect of frequency keeping where we expect this allocable cost to decrease materially as the result of the BBI.

276. The allocable cost of voltage support is paid by distributors in the relevant zone requiring the service.[102] Distributors must pay a nominated peak kVAr charge and a monthly peak penalty charge and may make or receive an annual residual payment so that the allocable cost is not under or over-recovered. We may calculate ancillary service regional NPB in respect of

102 As defined in Part 1 of the Code.

voltage support where we expect this allocable cost to decrease materially as the result of the BBI.

3.3.4.4 Calculate EASBD

277. We have not developed detailed processes or methodologies for calculating expected ancillary service benefits and disbenefits (**EASBD**) at this time. We expect to develop such processes and methodologies when we first calculate ancillary service regional NPB for an ancillary service BBI.

3.3.4.5 Calculate PVASRNPB

278. There are three steps required to calculate the present value of ancillary service regional NPB (**PVASRNPB**), detailed in the following sections.

Remove EASBD for customers or large plant that do not currently exist

279. Before finalising EASBD for a regional customer group and market scenario, we remove EASBD attributable to customers or large plant (≥ 10 MW) that do not currently exist.[103] We do this in proportion to the size of the load relative to the size of the node. For example, if a regional customer group's EASBD is $100m, the regional customer group's annual demand is 500 GWh, and the size of the new customer or large plant is 50 GWh, the regional customer group's EASBD will be $90m. By removing these benefits or disbenefits, we allow individual NPB to be calculated correctly under clause 83 when the new customer or large plant connects to the grid.

Calculate PVASRNPB

280. PVASRNPB is calculated as the weighted average value of EASBD for each regional customer group and market scenario (clause 53(6)). We also apply the discount rate (the BBI's standard method rate) to the ASRNPB at this step:

$$PVASRNPB = \frac{1}{\sum W_s} \sum_s \sum_t \frac{EASBD_{t,s}}{(1+discount\ rate)^t} \times W_s$$

where Ws is the probability weighting for the market scenario.

281. In accordance with clause 46(3), if a market scenario for a BBI includes a customer ceasing to be a customer, the market scenario will not be applied in the BBIs factual or counterfactual in respect of that customer (i.e. will have a weighting of zero).

Remove regional customer groups with a negative PVASRNPB

282. Clause 47 requires that a customer's individual NPB only be calculated in respect of their regional customer groups with positive present values of regional NPB. As a consequence, regional customer groups with negative present values of ancillary service regional NPB are excluded from the calculations of individual NPB and starting BBI customer allocations.

103 Except if the group is a future regional customer group, in which case we need to retain the regional NPB for that group in order to calculate the individual NPB for customers entering the group when they connect to the grid.

3.3.5 Calculate other regional NPB

283. In most cases, the regional NPB derived from a high-value post-2019 BBI will be one or more of market, ancillary service or reliability regional NPB. If we identify quantifiable regional NPB that is not one of these, we may calculate and apply it as other regional NPB.

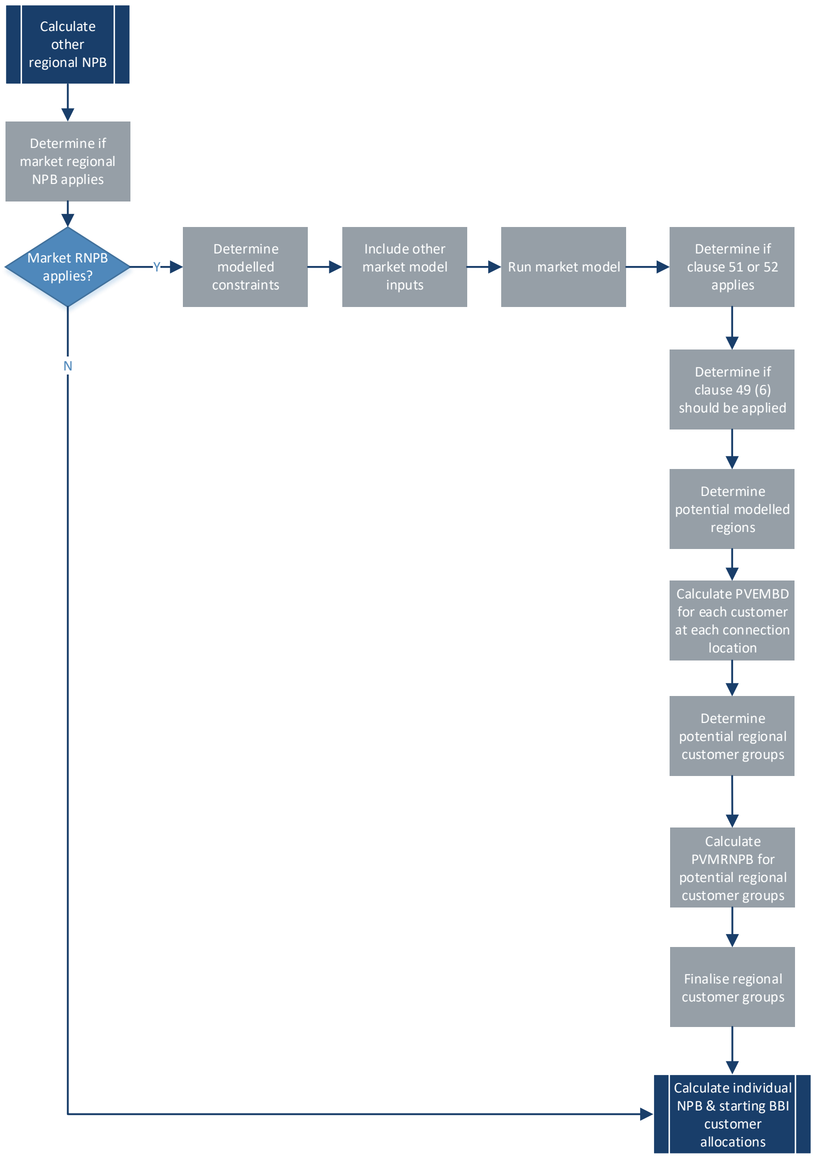
284. To be eligible for calculation, other regional NPB must meet the conditions of clause 55(2).

3.3.6 Calculate market regional NPB

3.3.6.1 Introduction

285. The purpose of this section is to provide a summary of the process undertaken to calculate market regional NPB for a high-value post-2019 BBI.

3.3.6.2 Overview diagram



Calculate market regional NPB

3.3.6.3 Determine if market regional NPB applies

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

3.3.6.4 Determine modelled constraints

287. In order to calculate market regional NPB for the BBI, we must determine the transmission constraints to be used in the market model. This is part of determining the investment grids (clause 49(2)). The transmission constraints used in the market model are the constraints on the HVDC link and the modelled constraints.

288. The TPM defines a modelled constraint as:

   a. a constraint affecting a new grid asset comprised in the BBI, or

   b. a constraint that would be alleviated materially if the BBI were fully commissioned, as determined by Transpower.

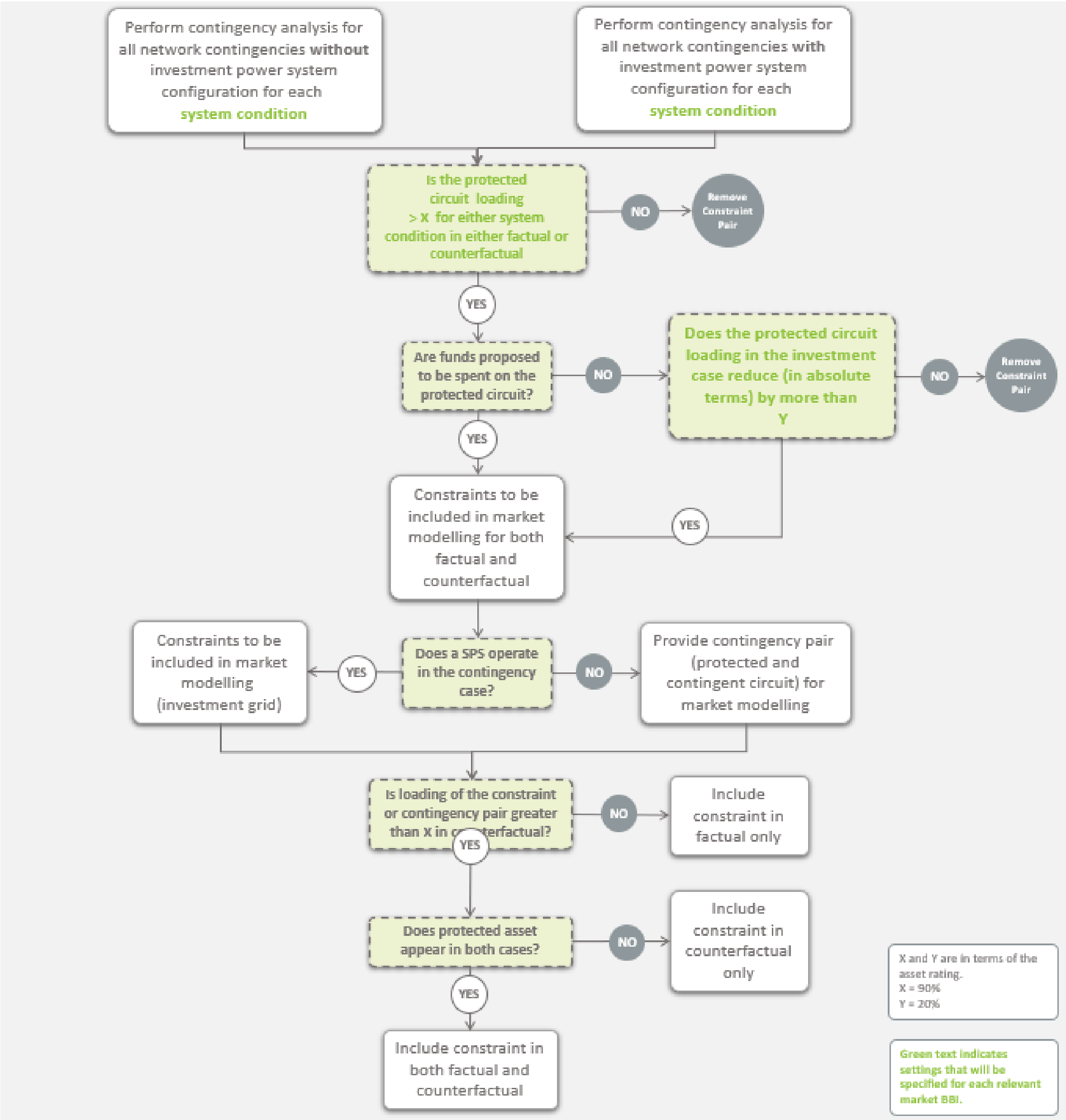
289. In order to model a point of constraint, the market model requires us to input either:

   a. the contingency pair that make up the point of constraint (comprised of a contingent branch and protected branch), or

   b. the constraint equation that can be used to include the effect of a special protection scheme (**SPS**) or a group constraint such as a voltage stability constraint.

290. We only include constraints in the market model that would be managed by the system operator as pre-contingent market constraints. These are derived using the process illustrated in the diagram below.[104]

[104] In the diagram, ”system conditions” means load and generation patterns that we use to highlight transmission issues we can reasonably expect to occur with currently available information and trends.



3.3.6.5 Include other market model inputs

291. In addition to the factual, counterfactual, market scenarios and modelled constraints that have been previously discussed, there are a number of other quantitative input assumptions required for the market model (e.g. the cost of self-supply).

292. These additional assumptions will be:

   a. adopted from the relevant assumptions used in the investment test for the BBI

   b. if there is no relevant investment test assumption or the relevant investment test assumption would not produce starting BBI customer allocations broadly proportionate to EPNPB, sourced from chapter 2 of this assumptions book, or

   c. if there is no relevant chapter 2 assumption or the relevant chapter 2 assumption would not produce starting BBI customer allocations broadly proportionate to EPNPB, determined by Transpower.

3.3.6.6 Run market model

293. SDDP is the market model used by Transpower.[105] We use SDDP as the market model because:

   a. SDDP meets all of the requirements of the definition of wholesale market model in the TPM,

   b. we currently use SDDP when undertaking the investment test where market benefits are being analysed, noting that the TPM generally requires alignment with the investment test under clause 43(5), and

   c. SDDP can adjust the scheduling of hydro generation depending on inflows and reservoir storage levels, thereby accounting for different hydrological scenarios as required by clause 46(1).

3.3.6.7 Determine if clause 51 or 52 applies

294. The TPM has two methods for calculating market regional NPB, in clauses 51 and 52. Clause 51 results in market regional NPB in quantity (GWh) terms. Clause 52 results in market regional NPB in dollar terms.

295. In general, clause 51 determines allocations based on the quantities of energy consumed during periods of benefit determined by Transpower. We determine these periods of benefit based on the price changes resulting from the BBI.

296. Clause 52 relies more than clause 51 on the pricing produced by the market model, which means the risks related to false precision must be considered when determining if one method should be preferred over the other. In this context, by false precision we mean allocations that vary between customers due to factors that are highly sensitive to uncertain input assumptions, or due to an artefact of the modelling framework that does not reflect reality (for example, one generator always being dispatched over another due to a slightly lower operational cost).

297. The TPM specifies circumstances in which we must apply either clause 51 or clause 52.

Clause 51

298. Clause 51(1)(a) requires us to use clause 51 where most of the benefits relate to new large generating plant. We apply this clause by:

   a. calculating the change in the present value of regional NPB for new large generating plant with EPNPB throughout the standard method calculation period (value A)[106]

   b. calculating the change in the present value of regional NPB for all generating stations with EPNPB throughout the standard method calculation period (value B)

   c. if value A is greater than 50% of value B (as weighted averages across market scenarios), we determine that clause 51(a) applies.

[105] Software | PSR – Energy Consulting and Analytics (psr-inc.com).

[106] A new large generating plant is defined as a large generating plant (> 10 MW capacity) for which the final decision to proceed with investment has not been made by the proponent at the time we make this calculation.

Clause 52

299. Clause 52(1)(b)(i) requires us to use clause 52 where most of the benefits relate to consumers avoiding high prices due to a lack of transmission and generation capacity during peak periods. We apply this clause by:

   a. estimating the change in the present value of regional NPB during times when there is a supply shortage during periods of peak demand in the counterfactual for regional demand groups with EPNPB during these times (value A)

   b. calculating the change in the present value of regional NPB for regional demand and supply groups with EPNPB during these times (value B)

   c. if value A is greater than 50% of value B (as weighted averages across market scenarios), we will determine that clause 52(1)(b)(i) applies.

When neither circumstance applies

300. When neither of the above circumstances applies, we will use clause 51 unless we consider it will not produce starting BBI customer allocations that are broadly proportionate to EPNPB (clauses 51(1)(b) and 52(1)(b)(ii)). It is appropriate for clause 51 to be the "default" method because it:

   a. removes risks related to false precision

   b. reduces the impact of Transpower discretion

   c. is simpler to understand and therefore provides greater transparency to stakeholders.

301. In general, clause 51 will produce starting BBI customer allocations that are consistent with an assumption that the magnitude of price changes due to a BBI are the same for supply and demand customers, and is the same over time and between market scenarios. Clause 51 will not be appropriate for BBIs where:

   a. we expect the change in price between the factual and counterfactual to be of a significantly greater magnitude for one group of beneficiaries compared to another

   b. this expectation is not sensitive to uncertain input assumptions across a reasonable range.

302. Clause 52(1)(b)(i) describes one situation where using clause 51 would not result in starting BBI customer allocations that are broadly proportionate to EPNPB (when the BBI is mitigating high prices due to a lack of generation and transmission capacity in the counterfactual).

303. Another situation in which we consider clause 51 will not produce starting BBI customer allocations that are broadly proportionate to EPNPB includes if a market BBI connects a much smaller region to the wider grid – e.g. at the 220 kV:110 or 66 kV interface. In this situation, we expect the absence of the BBI at this interface would have a greater impact on the price in the smaller region than the rest of the grid because the surplus or deficit is proportionally greater in the smaller region. In an extreme case, a market BBI may have no discernible impact on price in the wider market as the volume of generation or load being constrained is so much smaller than the market as a whole.

3.3.6.8 Determine if clause 49(6) should be applied

304. The TPM allows us to change the prices from our market model where we determine that the using the raw prices will not produce starting BBI customer allocations that are broadly proportionate to EPNPB. This will usually be to moderate the sensitivity of modelled prices and changes to prices to modelling assumptions and other inputs.

305. Examples of when we may determine that this is necessary are:

a. to reflect the long-run cost of self-supply (see section 2.3.7)

b. when the efficiency benefits of the BBI primarily result from lower capital costs to new generators (e.g. a transmission investment that enables low-cost generation), and where these lower costs are not adequately reflected in the prices from the market model.

3.3.6.9 Determine potential modelled regions

306. To determine the modelled regions for the BBI, we must identify the grid points of connection where customers are expected to experience the same or similar benefit (in proportion to their size). As a result, regions are determined based on the GXPs/GIPs that are expected to have the same or similar decrease/increase in price or quantity (clause 50(1)).

307. These differences will occur as the result of transmission constraints as, in general, a transmission constraint will result in increased prices downstream of it and decreased prices upstream of it. As a result, modelled regions are determined using the points of modelled constraint determined for a BBI in the AC network (see section 3.3.6.4) and the HVDC link constraints.

308. A potential modelled region for a BBI in the AC network is comprised of either:

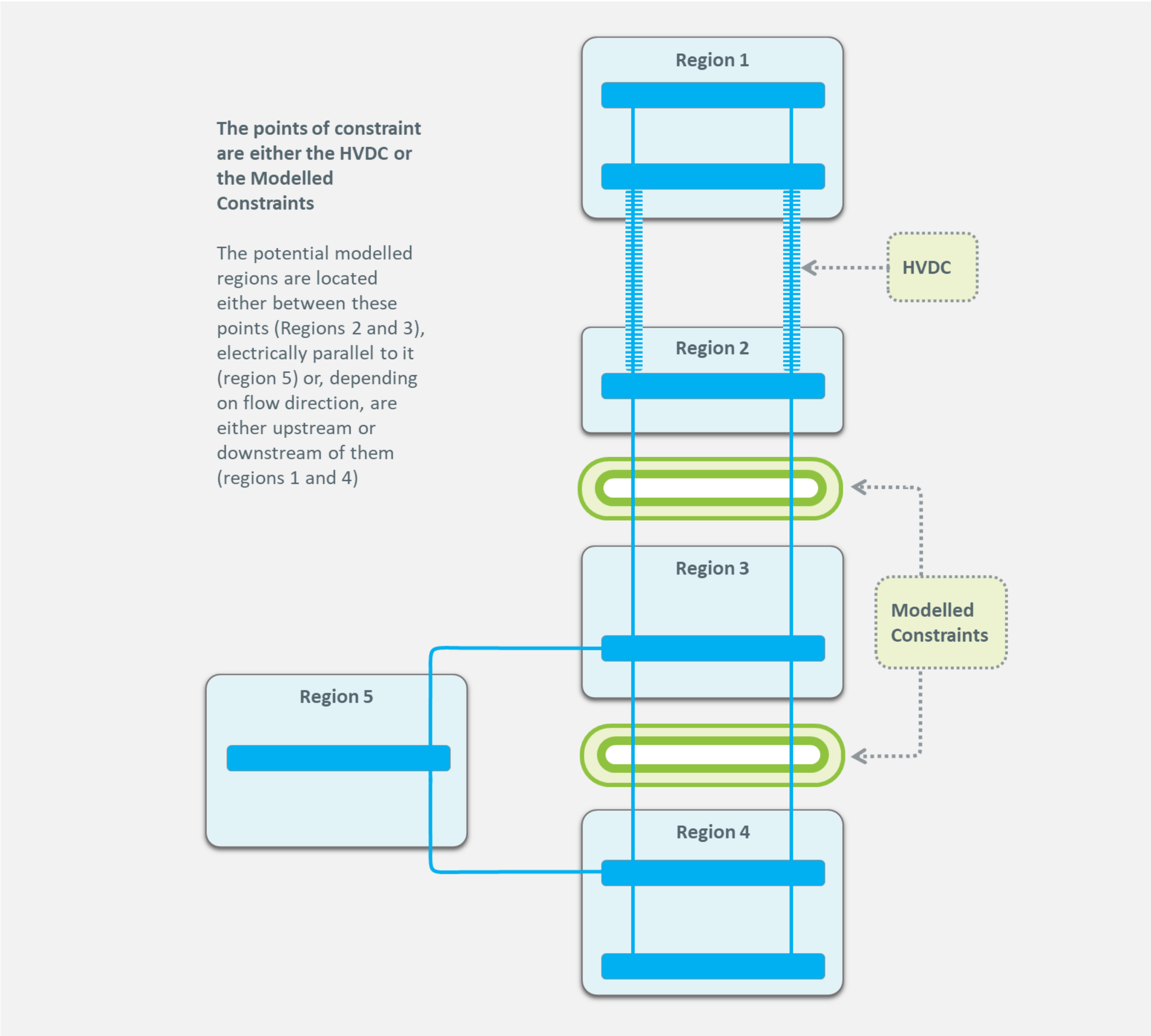
a. the GXPs/GIPs that exist between the points of modelled constraint or the HVDC link

b. the GXPs/GIPs that are downstream of the last point of modelled constraint or the HVDC link

c. the GXPs/GIPs that are upstream of the first point of constraint, or

d. the GXPs/GIPs that are electrically parallel to the modelled constraint.

309. An example is provided in the diagram below:



310. A BBI in the DC network will have two potential modelled regions – the North Island and the South Island.

311. The final modelled regions will be determined using the process detailed in section 3.3.6.13 which may result in adjacent potential modelled regions being aggregated.

3.3.6.10 Calculate PVEMBD for each customer at each connection location

312. The calculation of expected market benefits and disbenefits (EMBD) will differ depending upon if we are applying clause 51 or clause 52. The following sections describe the calculation under each clause.

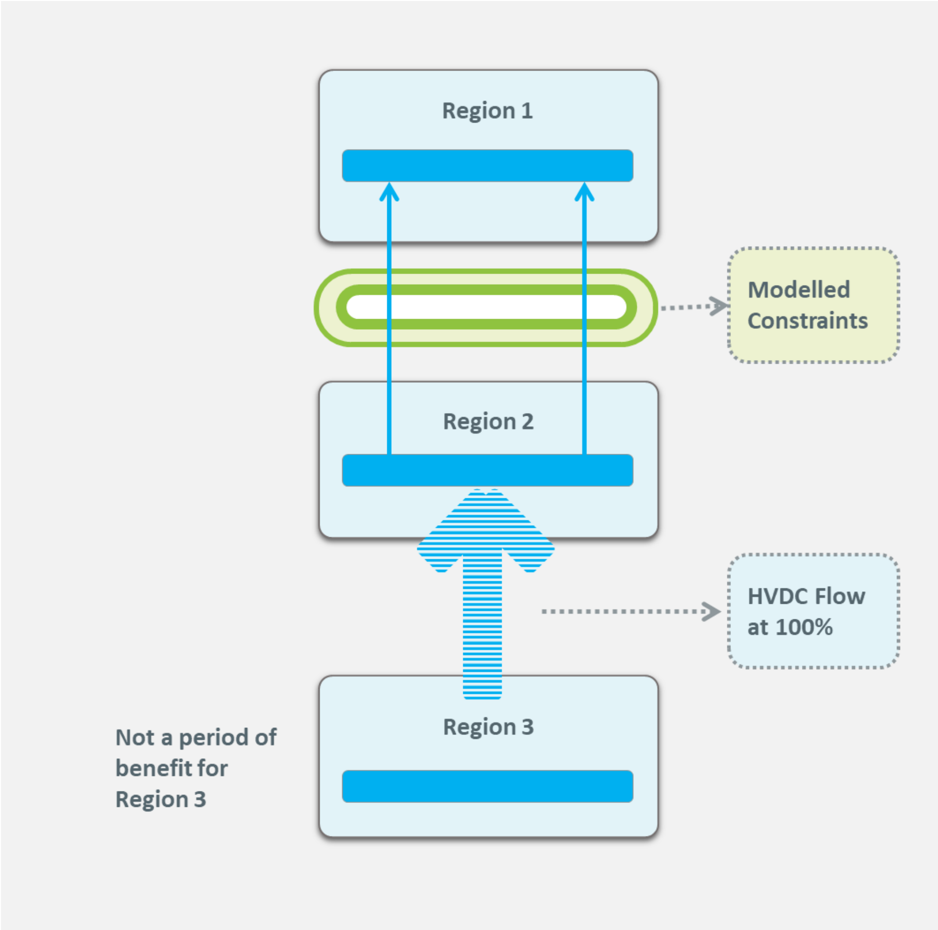
Calculate EMBD for each market scenario - clause 51

313. Clause 51(3)(b) requires us to determine the periods of benefit, being the periods during which the BBI is modelled to generate its primary market benefits.

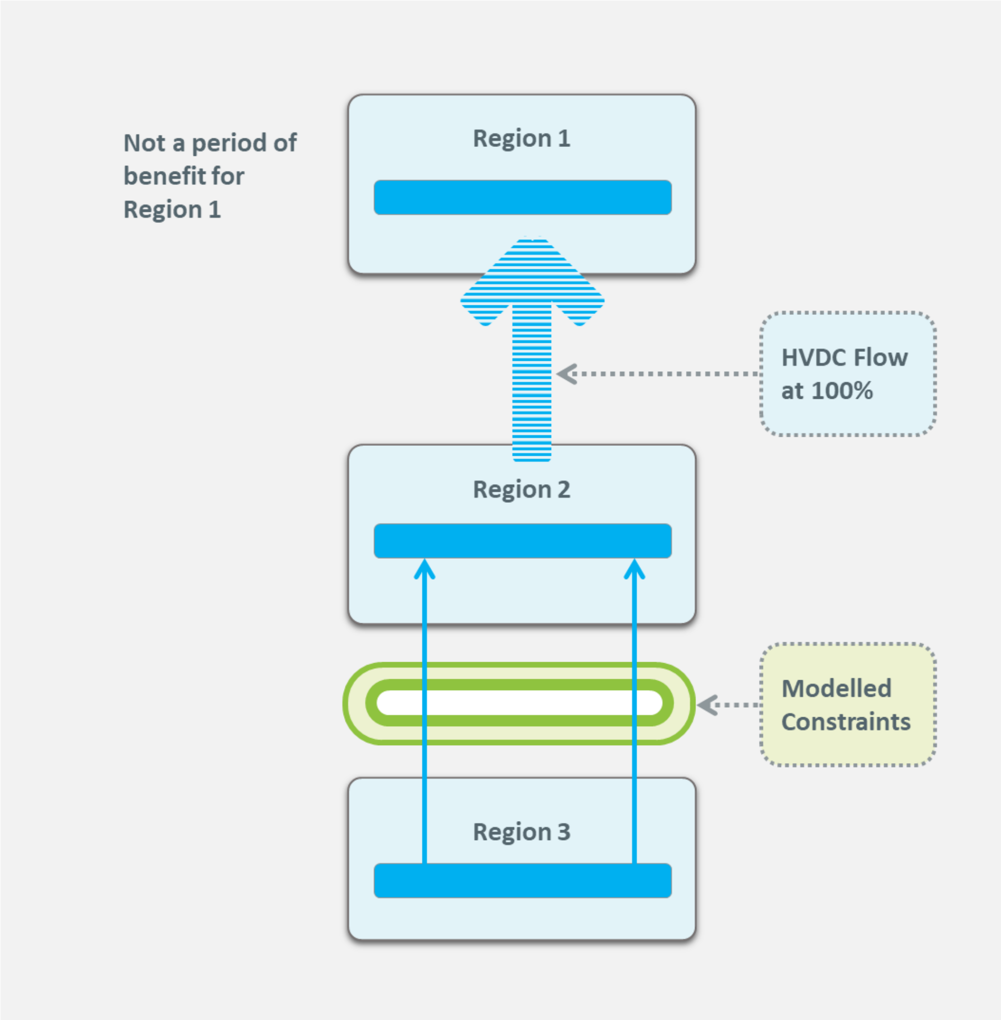
314. We determine the periods of benefit as the periods in which an AC constraint is binding in the counterfactual for all regional customer groups, with the following exception.

315. As shown in the diagram below, if a modelled constraint is electrically downstream of the HVDC link in a given load block, the periods of benefit for regions upstream of the HVDC link

(Region 3) in that load block do not include periods in which the HVDC link is binding and power is flowing across the HVDC link in the same direction as the modelled constraint.



316. Similarly, as shown in the diagram below, if a modelled constraint is electrically upstream of the HVDC link in a given load block, the periods of benefit for regions downstream of the HVDC link (Region 1) in that load block do not include periods in which the HVDC link is binding and power is flowing across the HVDC link in the same direction as the modelled constraint.



317. In accordance with clause 51(3), we calculate EMBD as follows.

318. EMBD for a customer at a connection location is calculated using generation and load outputs from the market model. Because some customers have both load and generation at a connection location, we calculate EMBD for load and generation separately.

319. The generation portion of EMBD for a customer at a connection location by the BBI is calculated using the following formula:

$$EMBD_{Gen_{cust,loc}} = Gen_{cust,loc,CF,e} - Gen_{cust,loc,CF,a} + GenDelta_{cust,loc}$$

where

$EMBD_{Gen_{cust,loc}}$ is the generation portion of EMBD for the customer ($cust$) at the connection location (loc).

$Gen_{cust,loc,CF,a}$ is the generation for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when prices are alleviated due to the BBI.

$Gen_{cust,loc,CF,e}$ is the generation for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when prices are exacerbated due to the BBI.

$GenDelta_{cust,loc}$ is the generation delta between the factual and counterfactual for the customer ($cust$) at a location (loc), i.e. factual generation minus counterfactual generation.

320. The load portion of EMBD for a customer at a connection location is calculated using the following formula:

$$EMBD_{Load\,cust,loc} = \; Load_{cust,loc,CF,a} - Load_{cust,loc,CF,e} + LoadDelta_{cust,loc}$$

where

$EMBD_{Load\,cust,loc}$ is the load portion of EMBD for the customer ($cust$) at the connection location (loc)

$Load_{cust,loc,CF,a}$ is the load for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when prices are alleviated due to the BBI.

$Load_{cust,loc,CF,e}$ is the load for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when prices are exacerbated due to the BBI.

$LoadDelta_{cust,loc}$ is the load delta between the factual and counterfactual for the customer ($cust$) at the connection location (loc), i.e. factual load minus counterfactual load.

321. Conceptually, these formulae use the periods in which a modelled constraint is binding in the counterfactual, i.e. when prices are suppressed upstream and elevated downstream of the constraint. We therefore count quantities exposed to those abnormal prices and apply positive or negative values to those quantities based on whether the customer benefits or disbenefits from the removal of those abnormal prices. We then add any changes in quantity between the factual and the counterfactual.

322. This captures, for example, the additional generation released by alleviating a constraint, but reflect that due to different storage levels in the factual compared to the counterfactual these could occur at different points in time. This also captures changes in volume for other reasons, for example if new generation can enter the market due to the BBI.

Calculate EMBD for each market scenario - clause 52

323. If using clause 52, EMBD is calculated in accordance with clauses 52(3) to (7) as follows:

$$\begin{aligned}&market\ benefit\ for\ regional\ demand\ group\ (\$) = \\ &\left[\left(deficit\ cost\ (\$/MWh) - price_F\ (\$/MWh)\right) \times load\ supplied_F(MWh)\right] - \\ &\left[\left(deficit\ cost\ (\$/MWh) - price_{CF}\ (\$/MWh)\right) \times load\ supplied_{CF}(MWh)\right]\end{aligned}$$

$$\begin{aligned}&market\ benefit\ for\ regional\ supply\ group\ (\$) \\ &\qquad = [price_F\ (\$/MWh) \times generation_F(MWh) - \ fuel\ cost_F(\$) \\ &\qquad - carbon\ emissions\ cost_F] \\ &\qquad - \ [price_{CF}\ (\$/MWh) \times generation_{CF}(MWh) - \ fuel\ cost_{CF}(\$) \\ &\qquad - carbon\ emissions\ cost_{CF}]\end{aligned}$$

where F and CF refer to the factual and counterfactual respectively, and the deficit cost is equal to the cost of self-supply (see section 2.3.7).

324. Note, battery storage both produces and consumes electricity. When consuming electricity its generation will be negative in the formula above, which is the same as treating its consumption of electricity from the grid as a production cost in accordance with clause 52(5).

325. Clauses 52(3)(b) and 52(4)(b) require us to include the modelled change in loss and constraint excess (**LCE**) allocations in the calculation of EMBD (outside the FTR market and unless we have applied clause 49(6)). At the time of writing, the Authority has announced it is reviewing the allocation of LCE.[107] The TPM therefore provides we do not have to model the change in LCE allocations for the high-value intervening BBIs (high-value post-2019 BBIs commissioned on or before 30 June 2023).

Common steps for clauses 51 and 52

326. There are a number of steps to calculate PVEMBD that are common to clauses 51 and 52.

Calculate present value EMBD

327. We calculate a market scenario-weighted EMBD by multiplying EMBD by the weighting for each market scenario and calculate EMBD as a present value in this step:

$$PVEMBD = \frac{1}{\sum W_s} \sum_s \sum_t \frac{EMBD_{t,s}}{(1 + discount\ rate)^t} \times W_s$$

where W_s is the probability weighting for the market scenario.

Remove PVEMBD for customers or large plant that do not currently exist

328. With the exception of potential future regional supply groups, before finalising EMBD for a regional customer group and market scenario, we remove EMBD attributable to customers or large plant (≥ 10 MW) that do not currently exist.[108] We do this in proportion to the size of the load relative to the size of the node. For example, if a regional customer group's EMBD is \$100m, the regional customer group's annual demand is 500 GWh, and the size of the new customer or large plant is 50 GWh, the regional customer group's EMBD will be \$90m. By removing these benefits or disbenefits, we allow individual NPB to be calculated correctly under clause 83 when the new customer or large plant connects to the grid.

Split loads with more than one customer at a connection location

329. We typically model loads at each connection location as a single load, even if there is more than one load customer at that connection location. Where this is the case, we will attribute the load portion of PVEMBD to each customer based on their offtake intra-regional allocator (IRA) as a proportion of the total of all customers' offtake IRAs at that connection location. Where one customer is a non-distribution customer and one customer is an electricity distribution business, we assume that the load growth at that connection location is wholly attributable to distributor customers, consistent with our demand forecasts for non-distributor customers which generally assume no load growth.

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107 [Market Brief - 21 December 2021 (ea.govt.nz).](#)

108 Except if the group is a future regional customer group, in which case need to retain the regional NPB for that group in order to calculate the individual NPB for customers entering the group when they connect to the grid.

3.3.6.11 Determine potential regional customer groups

330. Market regional NPB is calculated for a regional customer group. A proportion of the market regional NPB is then allocated to each customer within that group (see paragraphs 351 to 362).

331. A regional customer group is comprised of:

   a. a geographical region of the grid, and

   b. the GXPs or GIPs located within that region of the grid (a modelled region), and

   c. the customers connected at those GXPs or GIPs.

332. The purpose of a regional customer group is to identify the customers who receive similar benefits to one another and so that we can allocate a proportion of the regional NPB for the regional customer group to each customer based upon their historical grid offtake or injection. At this stage, we group GXPs and GIPs into potential regional customer groups and calculate regional NPB for each group. The regional customer groups may later be combined if they have similar benefits in proportion to their size (see section 3.3.6.13).

333. Having regional customer groups, rather than relying directly on the modelled benefits or disbenefits of each individual customer, allows us to limit the effect of false precision in our modelling. Potential regional supply groups are based on generating technology because we would expect plant with similar technology to have similar costs and to be dispatched similarly in the wholesale market, therefore gaining similar benefits from the BBI. The modelled dispatch, however, will be more sensitive to input assumptions compared to the wholesale market. Grouping these plants together removes the false precision associated with this sensitivity. For example, a 1 cent difference in operational costs between two marginal plants could lead to a significant difference in the modelled dispatch of one plant over the other.

334. In choosing regional customer groups it is also important to consider the effect of using historical IRAs. Regional demand groups are split into industrial and non-industrial offtake because non-industrial loads are likely to receive greater benefits in relation to their historical IRAs due to greater load growth compared to industrial loads. If industrial and non-industrial loads were grouped together, industrial loads would be paying for a portion of the benefits attributable to non-industrial loads in the relevant modelled region.

335. If a customer has both load and generation at the same connection location, we group them in either a supply or demand group based on their net private benefit, i.e. after offsetting generation disbenefits from load benefits (or vice versa). This is illustrated in the below table, in which all customers are at the same connection location and prices are decreasing due to the BBI. This results in a benefit for load customers and a disbenefit for generation customers. The disbenefit from generation is subtracted from the benefit from load for the customers with load and generation at the connection location (4 and 5).[109] Customers 1 and 4 would be allocated to the regional demand group and customers 2, 3, and 5 to the regional supply group.

109 The TPM does not allow for load and generation benefits and disbenefits to be combined across connection locations.

Customer	Node	Average load	Average generation	Load benefit or disbenefit	Generation benefit or disbenefit	Net benefit or disbenefit
1	ABC220	300MW	0MW	$300m	$0m	$300m
2	ABC220	0MW	100MW	$0m	-$100m	-$100m
3	XYZ220	0MW	100MW	$0m	-$100m	-$100m
4	DEF220	100MW	50MW	$100m	-$50m	$50m
5	UVW220	50MW	100MW	$50m	-$100m	-$50m

336. The potential load groups for each modelled region are:

a. industrial offtake

b. non-industrial offtake

c. load customers with significantly different benefits (but with the same sign) as other load customers in the same modelled region due to them having embedded generation.

337. The potential generation groups for each modelled region are:

a. wind generation

b. solar generation

c. geothermal generation

d. controlled hydro generation (all stations in the following hydro networks: Manapouri, Waitaki, Clutha, Waikaremoana, Waikato, Cobb, and Coleridge)

e. run-of-river hydro generation

f. thermal commitment generation

g. thermal peaker generation

h. battery storage

i. bio-fuelled generation

j. generation customers with significantly different benefits (but with the same sign) as other generation customers in the same modelled region due to them having embedded load.

338. We will separate a regional customer group into new and existing customers if:

a. we consider the benefits of the BBI primarily accrue to new customers. For example, an investment that primarily enables new generation may not have material benefits to existing generators (because the new generators would not exist without the BBI and therefore prices for existing generators in the same modelled region would be the same as or lower in the factual), or

b. the existing generation in the modelled region does not encompass all possible generation technologies so a new generator may not have a regional supply group to join.

339. Where create a regional customer group consisting entirely of new customers (a future regional customer group), we will determine a notional IRA for the group (see section 0).

3.3.6.12 Calculate PVMRNPB for potential regional customer groups

340. There are three steps required to calculate the present value of market regional NPB (**PVMRNPB**) for potential regional customer groups, detailed in the following sections.

Calculate PVMRNPB

341. The PVMRNPB for a potential regional customer group is the sum of the PVEMBD of all customers of the relevant type at connection locations within the modelled region for the regional customer group.

Remove regional customer groups with a negative PVMRNPB

342. Clause 47 requires that a customer's individual NPB only be calculated in respect of their regional customer groups with positive present values of regional NPB. As a consequence, the regional customer groups with negative present values of market regional NPB are excluded from the calculations of individual NPB and starting BBI customer allocations.

Convert quantity value of market regional NPB to dollars if required

343. Where we have calculated regional NPB for benefit classes other than market benefit and we have calculated market regional NPB under clause 51, we convert the quantity value of the market regional NPB for each regional customer group to dollars.

344. To do this we:

a. sum the positive market regional NPB for all regional customer groups calculated under clause 51

b. calculate the percentage of that total contributed by each regional customer group (X)

c. for the same regional customer groups, sum positive market regional NPB calculated under clause 52 at the same generating stations and nodes (Y)

d. multiply the dollar value of market regional NPB calculated at step 3 (Y) by each regional customer group's percentage contribution calculated at step 2 (X).

3.3.6.13 Finalise regional customer groups

345. We amalgamate potential regional customer groups to further reduce false precision where doing so will result in similar starting BBI customer allocations for the customers in those groups. This smooths out relatively insignificant variations between regional customer groups produced by the market model and helps ensure the starting BBI customer allocations are broadly proportional to EPNPB.

346. We apply three conditions when amalgamating potential regional customer groups:

a. the groups must be electrically adjacent or in the same modelled region prior to the amalgamation

b. we do not amalgamate regional supply groups with regional demand groups

c. we do not amalgamate groups across the North and South Islands if the difference in benefits relates to modelled constraints on the HVDC link.

347. We compare each potential regional customer group's PVMRNPB to total IRA ratio. This tells us whether customers' individual NPBs would be similar if groups are amalgamated compared to if they are not.

348. Starting with the potential regional customer group with the highest PVMRNPB/IRA ratio, we amalgamate groups (subject to the above constraints) with ratios 80% or more of that value. We then take the non-amalgamated group with the next highest ratio and amalgamate the non-amalgamated groups with ratios 80% or more of that value. We repeat this process until all potential regional customer groups have been considered.

349. This process is illustrated in the example below for regional supply groups, noting that for illustrative purposes we have reduced the number of generation groups from those listed in section 3.3.6.9.

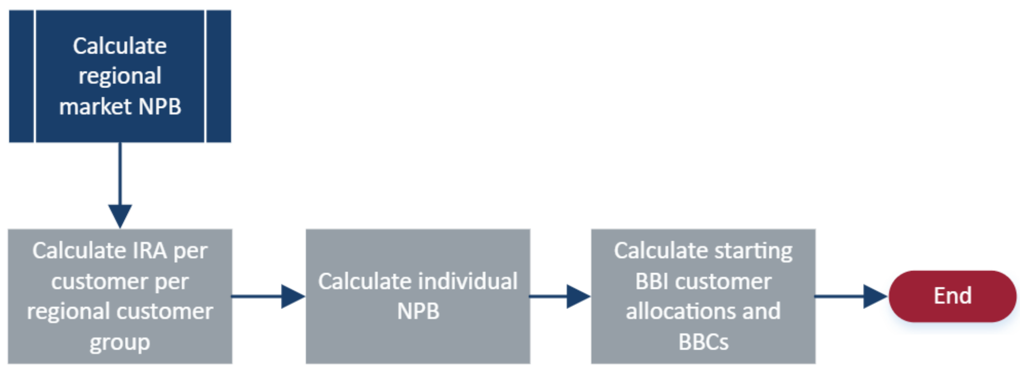
Modelled region	Generation group	PVMRNPB ($m or GWh)	IRA (GWh)	PVMRNPB/IRA ratio
LNI	wind gen	6	2	3.00
CNI	hydro gen	10	4	2.50
SI	hydro gen	20	10	2.00
UNI	thermal gen	3.5	2	1.75
UNI	hydro gen	1	3	0.33

350. In this example, the LNI wind gen regional supply group has the highest ratio of 3, 80% of which is 2.4. The LNI wind and CNI hydro gen groups will be amalgamated because the CNI hydro gen group's ratio is greater than 2.4 and the modelled regions of these two groups are electrically adjacent. All other ratios are lower than 2.4. We then move down to the next non-amalgamated group, the SI hydro gen group with a ratio of 2, 80% of which is 1.6. The UNI thermal gen group is the only non-amalgamated group with a ratio greater than 1.6, but its modelled region is not adjacent to the modelled region for the SI hydro gen group, and therefore cannot be amalgamated. Continuing this process, we find no more groups can be amalgamated.

3.3.7 Calculate individual NPB and starting BBI allocations

3.3.7.1 Introduction

351. The final step in the price-quantity method is to allocate positive regional NPB calculated for each regional customer group between the customers in that group and then use those individual NPBs to calculate starting BBI customer allocations for the BBI. This requires us to complete a series of three calculations, as illustrated below. The following sections describe how each calculation is performed.



Calculate individual NPB and *starting BBI customer* allocations

3.3.7.2 Calculate IRA per customer per regional customer group

352. To calculate a customer's individual NPBs for the regional customer groups it is a member of, we must calculate their IRA for each regional customer group. Clauses 65 to 67 relate to the calculation of IRAs.

353. For market and reliability BBIs, the IRA for regional demand groups can be either mean historical annual offtake (for non-peak BBIs) or mean historical coincident peak offtake (for peak BBIs), both measured in kWh. The IRA for regional supply groups is always mean historical annual injection (clause 65(1)).

354. Clause 65(8) requires use of between 1 and 100 peak offtake trading periods per capacity year to calculate mean historical coincident peak offtake, with the number of peak offtake trading periods referred to as T. We use a T=100 for the following reasons:

    a. while peak BBIs may initially only provide benefits during a small number of trading periods, as demand grows over time we expect the number of trading periods in which the capacity is used to grow. Therefore, using a low T value risks sending a price signal that is too strong – incentivising economically inefficient peak avoidance

    b. using a low T value would risk customers receiving a higher or lower starting BBI customer allocation for a peak BBI due to chance. A higher T value will reduce the sensitivity of the calculation and be a more reliable measure of average offtake during peak periods.

355. Clause 65(2) specifies the IRAs for ancillary service regional customer groups.

Specified ancillary service	Type of ancillary service regional customer group	IRA
Instantaneous reserve	Regional supply group	Mean historical annual injection
Frequency keeping	Regional demand group	Mean historical annual offtake
Voltage support	Regional demand group	Mean peak kVar

356. IRAs are calculated based on injection or offtake (per trading period) or nominated peak kVar (per capacity year) for the five complete capacity years immediately preceding the final investment decision date for the BBI (CMP B) (clauses 65(5) to 65(9)).

357. 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, injection or mean peak kVar) (clauses 66 and 83(3)(a)).

358. 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 in accordance with clause 67. This is necessary so that the adjustment provisions in the TPM will work correctly when new customers join the group.

3.3.7.3 Calculate individual NPB

359. A customer's individual NPB for the BBI is the sum of the present value of net private benefit (**PVRNPB**) for each regional customer group with positive PVRNPB of which the customer is a member, multiplied by the customer's IRA for the group as a proportion of the total of all customers' IRAs for the group (clause 47).

3.3.7.4 Calculate starting BBI customer allocations and BBCs

360. The starting BBI customer allocations for the BBI are calculated as each customer's individual NPB divided by the sum of all customers' individual NPBs (clause 43(1)).

361. Note that customer allocations are fixed over the lifetime of the BBI, except to the extent they are adjusted when specific adjustment events occur, such as a new customer or large plant entering or exiting.

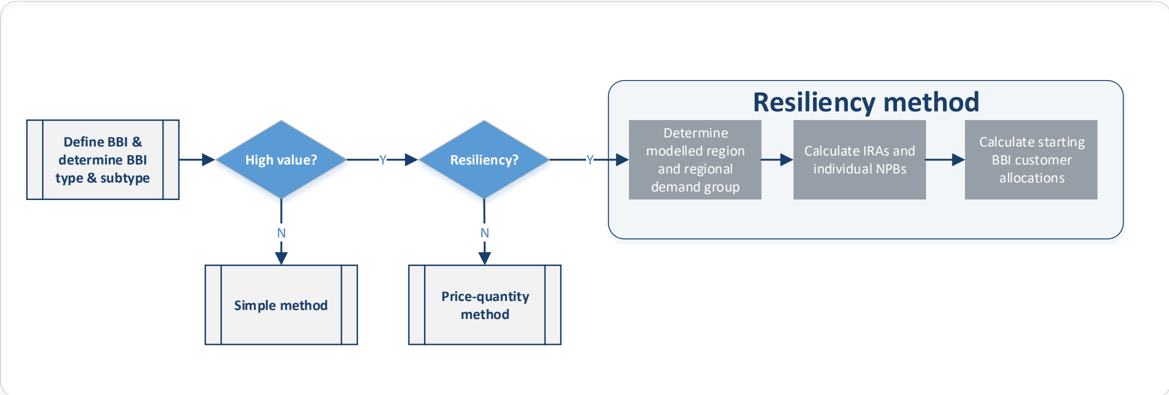
362. A customer's BBC for the BBI is calculated by multiplying the BBI's covered cost by the customer's BBI customer allocation (clause 35(2)).

3.4 The resiliency method (standard method)

3.4.1 Introduction

363. The resiliency method is used to calculate EPNPB when we determine that a high-value post-2019 BBI's primary investment need relates to mitigating the risk of a HILP event or cascade failure. The criteria applied in order to make this determination is discussed in section 3.2.4. In this case the BBI is referred to as a resiliency BBI.

364. The resiliency method requires three processes to be performed, as illustrated in the diagram below.



365. Sections 3.4.1.1 to 3.4.1.3 provide a description of each process.

3.4.1.1 Determine modelled region and regional demand group

366. Conceptually, resiliency BBIs are very similar to reliability BBIs (refer paragraphs 254 to 270). However, for resiliency BBIs there is only one modelled region and one regional customer group (clause 58).

367. The modelled region is the region that would be affected by the HILP event or cascade failure without the BBI. This region will be either:

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

b. the region in which the risk of the HILP event is mitigated.

368. Once the modelled region is determined, the regional customer group (a regional demand group) will be comprised of all offtake customers located within the modelled region, except grid-connected batteries.

369. As an example, take a region that is currently supplied by a single line, which is vulnerable to extended interruptions if a tower were to fail due to flooding. If a new line is built on a different route, supply into the region will be more resilient. Therefore, the regional demand group will be all loads supplied by the new line.

3.4.1.2 Calculate IRAs and individual NPBs

370. For resiliency BBIs, the individual NPB for each beneficiary customer is equal to each customer's IRA.

371. The IRA for the resiliency method is mean historical annual offtake (clause 65(3)). This IRA is calculated based on the customer's average historical annual offtake at all connection locations in the modelled region during the five complete capacity years before the final investment decision date for the BBI (CMP B) (clause 65(5)).

372. 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, injection or mean peak kVar) (clauses 66 and 83(3)(a)).

3.4.1.3 Calculate starting BBI customer allocations and BBCs

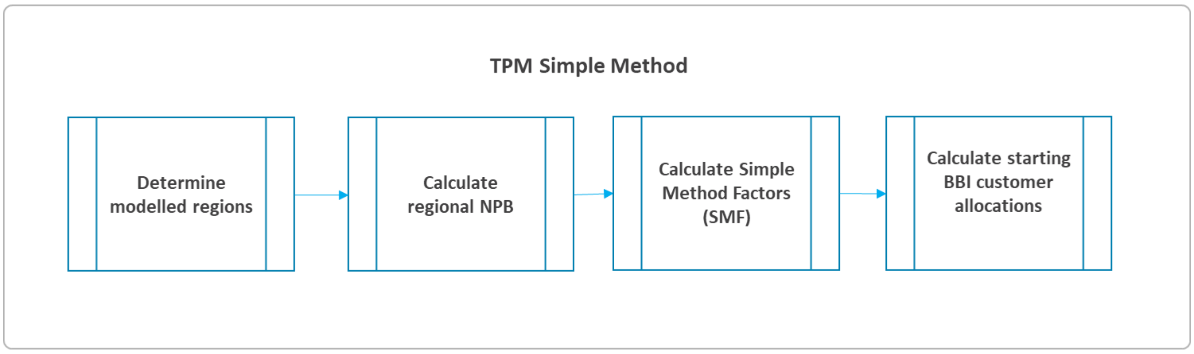
373. The starting BBI customer allocations for the BBI are calculated as each customer's individual NPB divided by the sum of all customer's individual NPBs (clause 43(1)).

374. A customer's BBC for the BBI is calculated by multiplying the BBI's covered cost by the customer's BBI customer allocation (clause 35(2)).

3.5 The simple method

375. The simple method is used to calculate EPNPB for a low value BBI.[110]

376. The simple method requires a series of five processes to be performed, as illustrated in the diagram below.



377. Clauses 59 to 67 contain the rules for these processes.

378. Unless there is an adjustment event (Part F), the simple method uses the same regional and individual customer allocators (NPBs) for the whole simple method period to which the allocators relate (i.e. the simple method allocators are not calculated per BBI but rather per simple method period). A simple method period is a period of, typically, five years (clause 60).

379. The simple method modelled regions and allocators for the first simple method period are published in chapter 4 of this assumptions book.

3.5.1 Determine modelled regions

380. The modelled regions for the simple method are connection regions and the HVDC link (clause 62(1)).

381. Connection regions are determined by analysing historical half hourly data used to set market prices (Arcflow data).[111] The connection regions for a simple method period are determined from the Arcflow data for a five capacity year period preceding the start of the simple method period (CMP C). CMP C for the first simple method period is 1 September 2016 to 31 August 2021.[112]

382. Clause 62(4) details how Transpower determines the connection regions. The process we use when doing so is represented in the diagram below.

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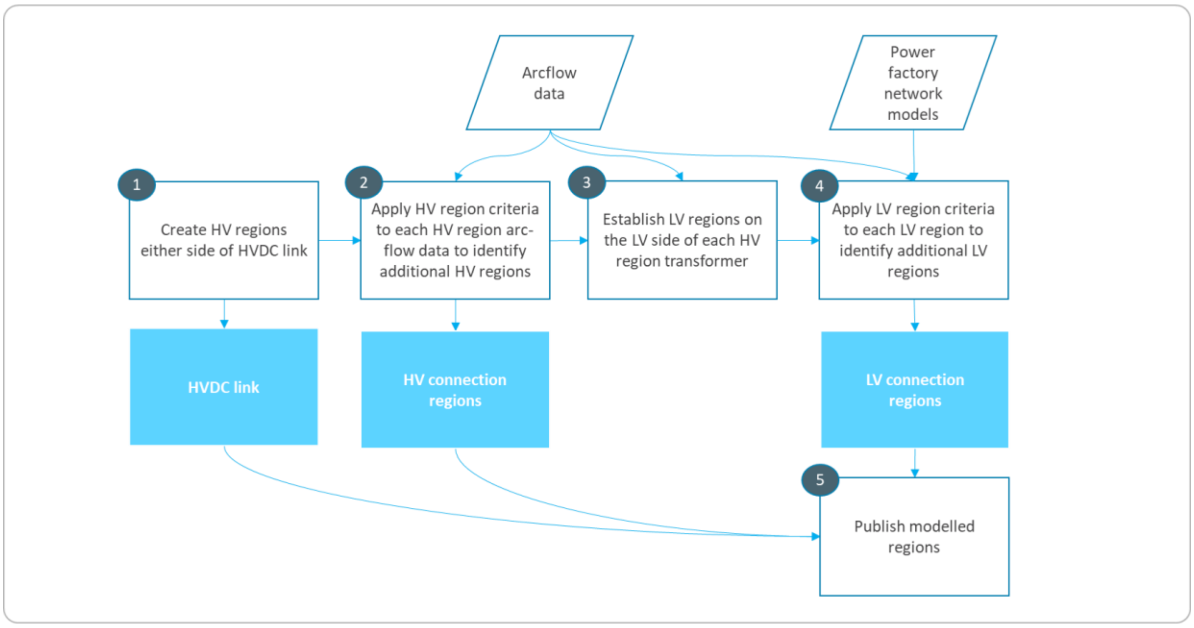
110 The process used to determine that a BBI is low-value is detailed in section 210.

111 The Arcflow data is the MW flow scheduled along an arc in the transmission network. Arcflow data is the MW flows calculated in the market clearing engine (SPD) and used in the determination of final wholesale electricity nodal prices.

112 The first simple method period started on 24 July 2019 so that all low value post-2019 BBIs are captured in it. This means CMP C for the first simple method period overlaps.



383. The connection regions that result from this process and the HVDC link are the modelled regions for the simple method period.

3.5.1.1 Determine high voltage connection regions (steps 1 and 2)

384. High voltage (**HV**) connection regions comprise grid assets greater than or equal to 220kV.

385. HV connection regions are defined on either side of the HVDC link by analysing Arcflow data.

386. Possible HV connection region boundaries are drawn across a set of interconnection branches (interfaces) that would electrically separate two parts of the grid at the HV level.[113]

387. A final HV connection region boundary is established where the electricity flow across an HV interface satisfies two criteria:

a. first, there is a prevailing electricity flow across the interface. This criterion is satisfied if, for at least 95%of the trading periods over CMP C, the electricity flow for all branches in the interface is in the same direction as the total flow across the interface[114]

b. second, once a prevailing directional flow has been established across the interface, we test to determine if the prevailing flow can be isolated. We conclude that it can be isolated if the directional flow of electricity on the "other side" of the boundary bus(es) is variable.[115] The other side of the boundary bus refers to the HV branches

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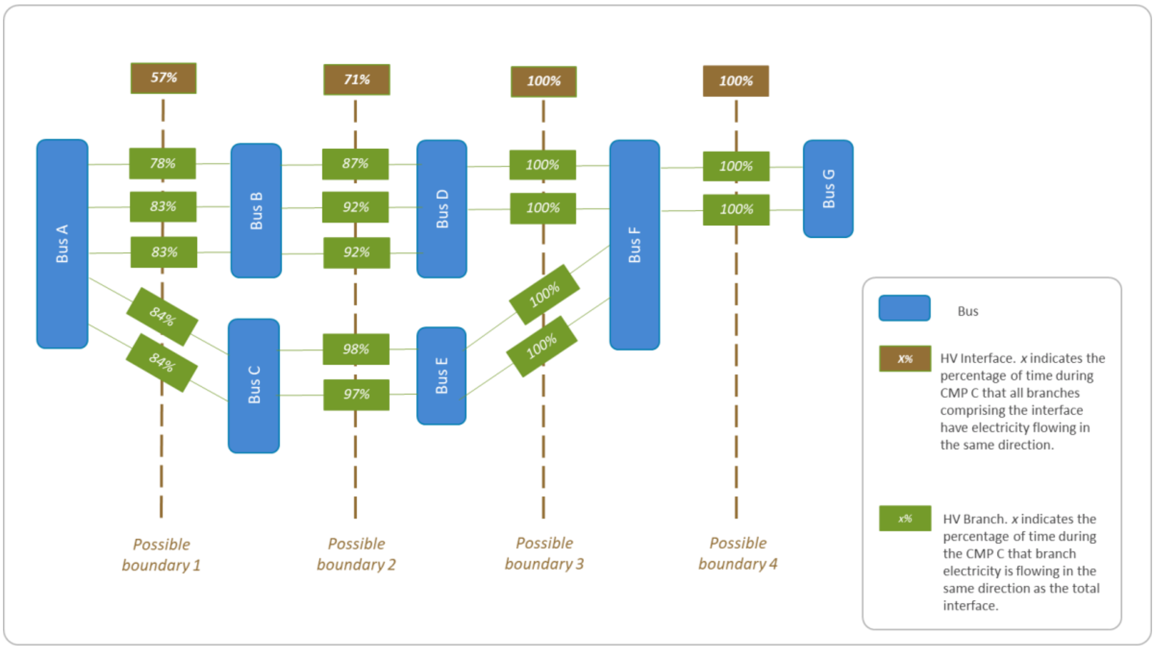
113 An interface is a collection of branches. A branch is an electrical link between two market nodes. Branches in the context of the simple method only apply to interconnection branches. Interface branch assets that make up the HV connection region boundary are allocated to each HV connection region in proportion to the electricity flows across the interface.

114 We use a 95% threshold to determine a prevailing flow and allow for up to 5% of trading periods to be impacted by abnormal conditions such as maintenance outages while still capturing the prevailing flow concept.

115 For a potential boundary interface, the boundary bus(es) for that interface are the electrical bus(es) that connect branch(es) that form part of that interface and connect branch(es) that do not form part of that interface.

that are connected to the boundary bus but are not part of the interface and do not directly connect the boundary buses (in the case with two boundary buses). Each branch is tested for variable directionality by analysing its Arcflow data. The upper and lower 5th percentiles of Arcflow data are removed.[116] If the remaining electrical flow across the branch is not all in the same direction, then that branch is considered variable. There must be at least one variable branch at each boundary bus to satisfy this criterion.

388. The first criterion above (prevailing flow of electricity across a possible boundary) is illustrated in the following simplified example.



389. In this example:

a. Possible boundary 1 is comprised of three HV branches between Bus A and Bus B and two HV branches between Bus A and Bus C. These five branches form the HV interface across the potential boundary. In this case, the five branches are all flowing in the same direction 57%[117] of the time during CMP C (as shown in the brown box). This does not meet the 95% criterion for a prevailing electricity flow across the interface and so possible boundary 1 is discarded.

b. Possible boundary 2 is also comprised of five HV branches, three between Bus B and Bus D and two between Bus C and Bus E. These five branches form the HV interface across the potential boundary. In this case, the five branches are all flowing in the

116 The rationale for using the upper and lower 5th percentiles is the same as that explained in footnote 24 above

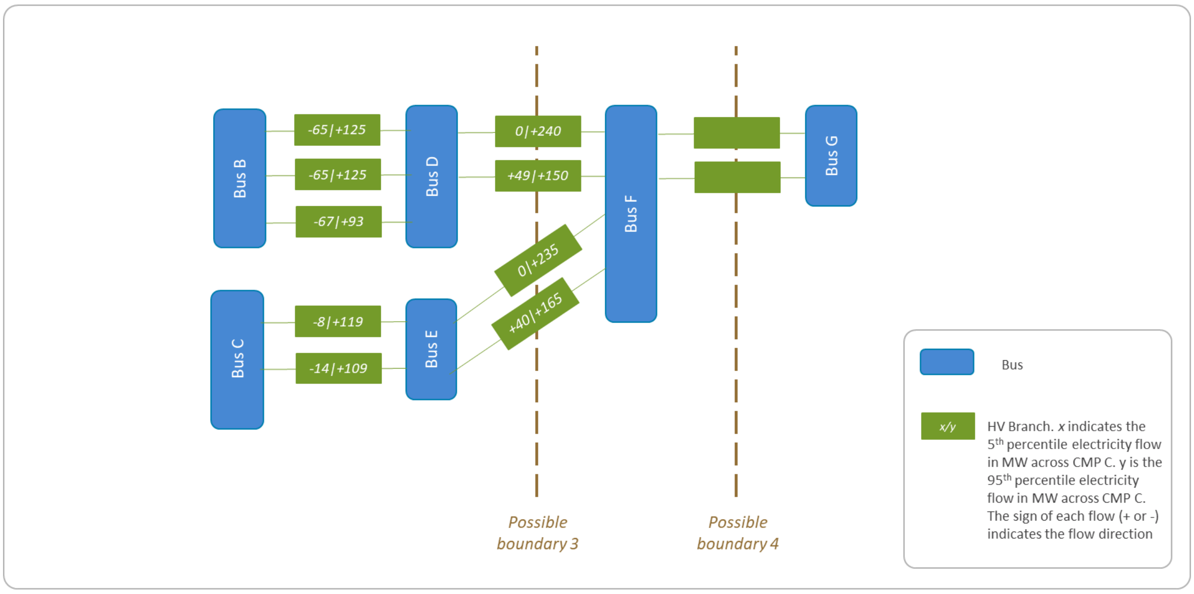
117 We calculate the percentage of time that all branches in an interface are flowing in the same direction by considering the state in each CMP C trading period. There are approximately 87,600 trading periods in CMP C. For possible boundary 1, the electricity flow across the five HV branches were all in the same direction as the HV interface flow (be they from left to right or right to left) in 49,932 (57% of 87,600) trading periods. The threshold for satisfying the prevailing electricity criteria is 83,220 (95% of 87,600) trading periods where all interface branches are moving electricity in the same direction as the interface.

same direction 71% of the time during CMP C (as shown in the brown box). This does not meet the 95% criterion for a prevailing electricity flow across the interface and so possible boundary 2 is discarded.

c. Possible boundary 3 is comprised of two HV branches between Bus D and Bus F and two HV branches between Bus E and Bus F. These four branches form the HV interface across the potential boundary. In this case, the four branches are all flowing in the same direction 100% of the time during CMP C (as shown in the brown box). This exceeds the 95% criterion for a prevailing electricity flow across the interface. Possible boundary 3 progresses to the second criterion to determine whether this prevailing flow can be isolated.

d. Possible boundary 4 is comprised of two HV branches between Bus F and Bus G. These two branches form the HV interface across the potential boundary. In this case, the two branches are flowing in the same direction 100% of the time during CMP C (as shown in the brown box). This exceeds the 95% criterion for a prevailing electricity flow across the interface. Possible boundary 4 progresses to the second criterion to determine whether this prevailing flow can be isolated.

390. The second criterion above tests the two possible boundaries that satisfy the first criterion (possible boundary 3 and possible boundary 4) to determine if the prevailing flows across the relevant HV interfaces can be isolated.



391. In this example:

a. For possible boundary 3, the boundary buses are Bus D and Bus E. We test the three HV branches between Bus D and Bus B and the two HV branches between Bus E and Bus C to see if both boundary buses (D and E) have at least one branch where the electricity flow is variable across CMP C. These five branches are "on the other side" of possible boundary 3 because they are connected to Buses D and E and are not interface branches. In this case, all the five branches have variable flow because the 5th percentile flow is negative and the 95th percentile flow is positive (in a directional sense) in all cases.[118] We conclude that the prevailing electricity flow across the HV interface can be isolated and an HV region is established on either side of boundary 3.

b. For possible boundary 4, the boundary bus is Bus F. The prevailing electricity flow across possible boundary 4 can be isolated if at least one of the two HV branches between Bus F and Bus D is variable and at least one of the two HV branches between Bus F and Bus E are variable. In this case, none of the four branches are variable as the 95th percentile is positive in each case and the 5th percentile is either zero or a positive value. We conclude that the prevailing electricity flow across the HV interface cannot be isolated from the prevailing electricity flow across the HV interface for boundary 3.

c. This results in the confirmation of a single HV to HV boundary at boundary 3 (where there is a prevailing electricity flow across the HV interface that can be isolated). An HV connection region is established on either side of boundary 3.

3.5.1.2 Determine low voltage connection regions (steps 3 and 4)

392. Low voltage (**LV**) connection regions comprise grid assets less than 220kV and include the LV nodes and branches from the interconnecting substation (including the interconnecting transformer).

393. LV connection regions are initially established on the LV side of each interconnecting transformer branch that connects part of the LV interconnected grid to an HV connection region (clause 62(4)(c)).

394. If an LV connection region is connected to more than one HV connection region then it is necessary to split the LV connection region at the branch where there is the lowest average electricity flow (the minimum transfer branch). We use Arcflow data to rank the LV branches within the LV connection region and create separate LV connection regions on either side of the minimum transfer branch. We repeat this exercise until all LV connection regions are connected to only one HV connection region (clause 62(4)(d)).

395. If after that process there is more than one HV to LV interconnection branch into an LV connection region, we need to evaluate if the LV connection region could be further split into separate LV connection regions. This could occur at the branch with the lowest average electricity flow in the LV connection region based on Arcflow data (the minimum transfer branch) (clause 62(4)(e)). This possible boundary would be confirmed if the electricity flow across the minimum transfer branch is low relative to total electricity flows between the interconnecting transformers within the LV connection region.

396. To determine whether the electricity flow across the minimum transfer branch is low relative to total electricity flows between the interconnecting transformers within the LV connection region we apply an injection test to a pair of HV to LV interconnecting sites (substations where the HV to LV interconnecting transformers are located) using a PowerFactory model.[119] The test involves adding 10MW of generation at the HV node of one of the interconnecting sites then adding a 10MW load at the LV node at the other interconnecting site. We observe the change in electricity flow across the minimum transfer branch and

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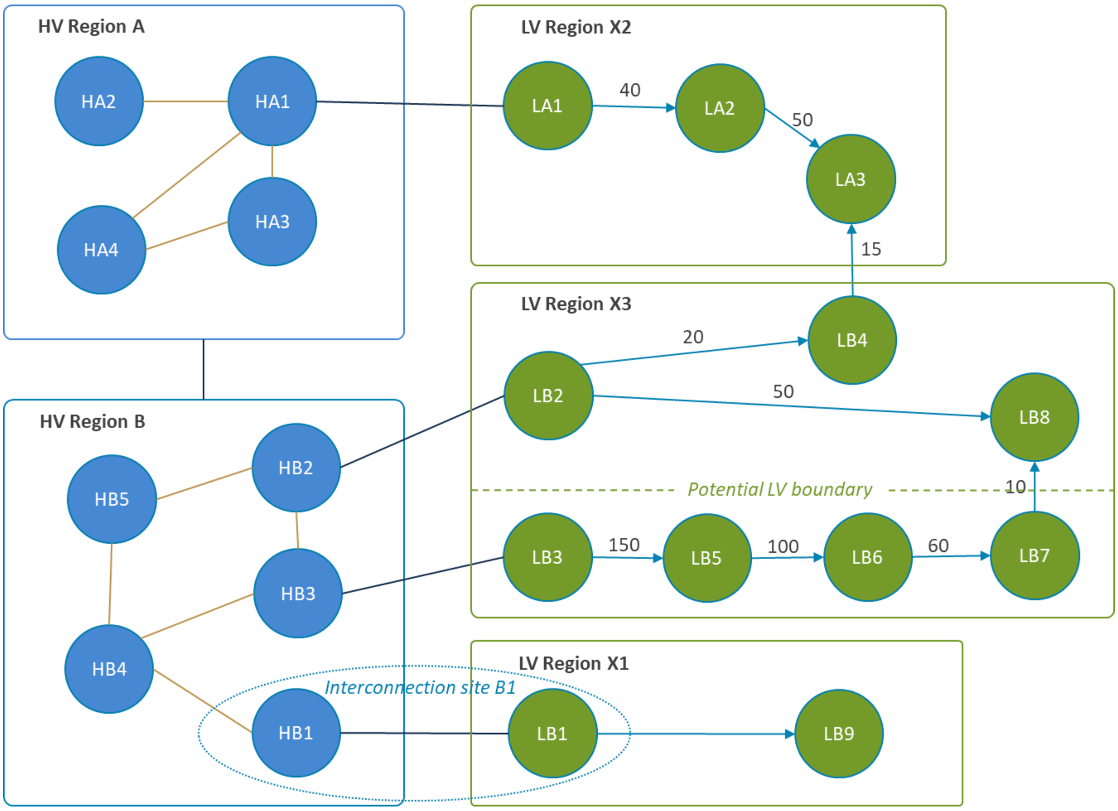
118 The interface branches for possible boundary 3 are the two branches between Bus D and Bus F and the two branches between Bus E and Bus F.

119 We use the most recently published Electricity Market Information (EMI) model at the time that we determine our connection regions for each simple method period.

conclude that the electricity flow is low if it changes by 1MW or less (i.e. 10% or less). We repeat the test in the opposite direction.

397. Below is a simplified example of how LV connection regions are determined.



a. LV Region X1 can be established as an LV connection region without further analysis of electricity flows as LV Region X1 is connected[120] to only one HV connection region (HV Region B) and is connected by only one HV to LV interconnection branch.

b. The interconnection branch transformers LA1 and LB2 are part of one LV interconnected grid that is connected to more than one HV connection region (HV Region A and HV Region B). Separate LV connection regions must be established either side of the minimum transfer branch so that each LV connection region is connected to only one HV connection region. The minimum transfer branch is between LA3 and LB4 where the average electricity flow magnitude is 15MW. Creating two LV connection regions, LV Region X2 and LV Region X3, either side of this branch ensures the two LV connection regions are each connected to only one HV connection region.

c. LV Region X3 includes two HV to LV interconnection sites (LB2 and LB3) so it is necessary to determine if LV Region X3 should be split into separate LV connection regions. Separate LV connection regions can be established on either side of the minimum transfer branch within LV Region X3 if electricity flow on that branch is low relative to total electricity flows between interconnecting sites in LV Region X3. The

120 "Connected" in the context of the simple method connotes an electrical connection. The electrical connection is based on the connection in the power flow case used in the PowerFactory model referenced in section 3.5.1.2.

minimum transfer branch within LV Region X3 is between LB7 and LB8 where the average electricity flow magnitude is 10MW.

d. Separate LV connection regions are established on either side of the minimum transfer branch (LB7_LB8) if average electricity flow magnitude on the branch is low relative to total electricity flows between interconnection sites B2 and B3. To assess this:

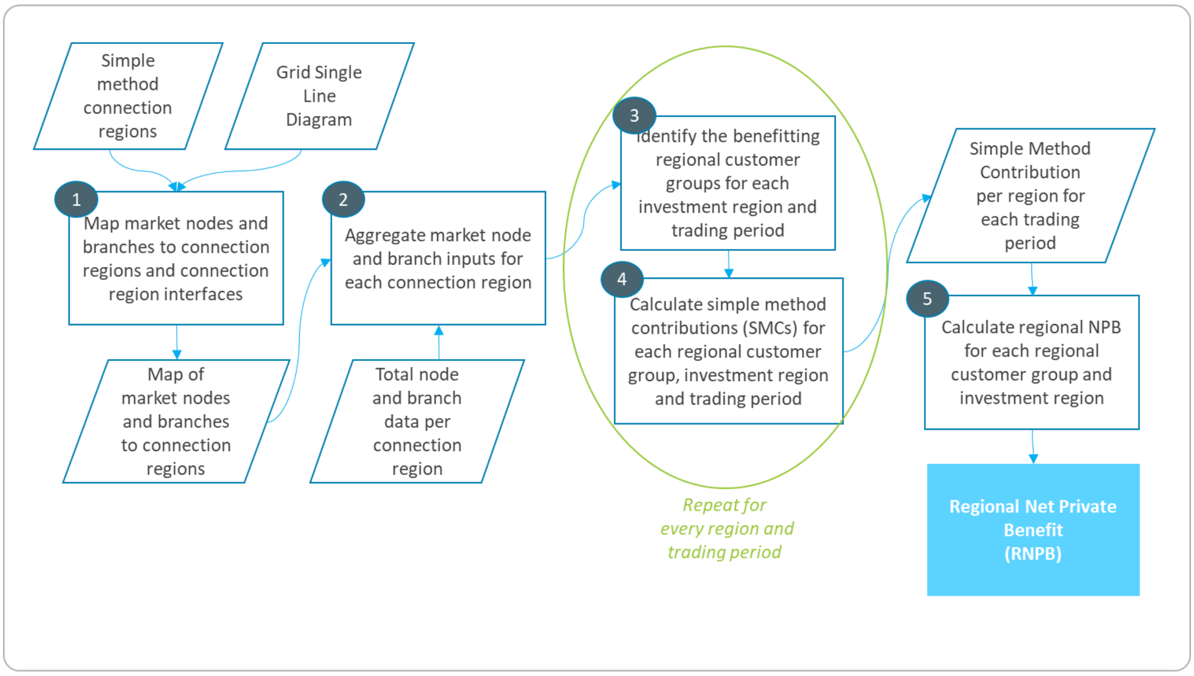
- Injection test 1: Generation into LV Region X3 is increased at node HB2 by 10MW and offtake is increased at node LB3. If the flow of electricity across branch LB7_LB8 is impacted by less than 10% of the additional 10MW (i.e. falls to no less than 9 MW) then we conclude that the flow is low relative to total electricity flows between the nodes in the HB2_LB3 direction.
- Injection test 2: The test is repeated in the opposite direction. Generation is increased by 10MW at node HB3 and load is increased by 10MW at node LB2. Electricity flow across branch LB7_LB8 is low relative to total electricity flows between the nodes in the HB3_LB2 direction if it increases to no more than 11MW.
- If the average of both injection tests result in no more than a 1MW change in electricity flow across branch LB7_LB8 then separate LV connection regions are created on either side of this boundary.

3.5.2 Calculate regional NPB

398. Regional NPB is calculated for each regional customer group. Each connection region will have two regional customer groups– a regional demand group (the offtake customers located within that connection region) and the regional supply group (the injection customers located within that connection region) (clause 63).

399. A regional customer group will have a different regional NPB value for each different investment region (the modelled region in which the BBI is located). Regional NPB is a weighted average of the regional customer group's simple method contribution (**SMC**) for an investment region over CMP C for the relevant simple method period.

400. The formulae used to calculate regional NPB are in clause 64. The process we follow when completing these calculations is depicted in the illustration below.



3.5.2.1 Map market nodes and branches to connection regions and connection region interfaces (step 1)

401. Using the SPD diagram that was current at the end of the CMP C for the simple method period and the connection region determination, we map: [121]

  a. each market node to the connection region in which it is located

  b. each branch to the connection region interface it pertains to. [122]

3.5.2.2 Aggregate market node and branch inputs for each connection region (step 2)

402. The raw offtake and injection data we use for this step are the wholesale market final pricing ”nodal prices and volumes” datasets published on the Authority’s website. We use the datasets published at the time we calculate regional NPB.

403. To calculate offtake and injection at market nodes, embedded generation cleared in the market is netted off against market load data at the same electrically equivalent market node(s) to produce net generation (injection) or net load (offtake) at that these market nodes.

404. We calculate regional demand group offtake for each trading period during CMP C by aggregating net market load data from all market nodes mapped to a connection region.[123]

405. We calculate regional supply group injection for each trading period during CMP C by aggregating net market generation data from all market nodes mapped to a connection region.

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121 The SPD diagram can be found at https://www.transpower.co.nz/system-operator/key-documents/maps-and-diagrams

122 A connection region interface is an interface that connects one connection region to another.

123 We will exclude any trading periods for which we do not consider we have reliable data.

406. We calculate regional interface electricity flows for each connection region and each trading period during CMP C by summing the market branch flow data for all interface branches mapped between connection regions.

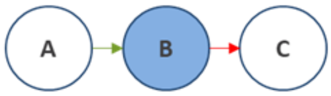
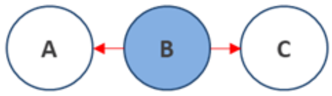
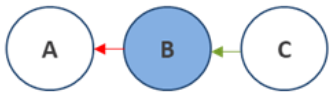
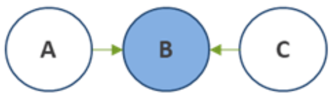
3.5.2.3 Identify the benefitting regional customer groups for each investment region and trading period (step 3)

407. For each investment region in each trading period during CMP C, we use the regional interface electricity flows to identify the benefitting regional customer groups, being:

a. regional demand groups that import electricity from the investment region either directly or indirectly

b. regional supply groups that export electricity to the investment region either directly or indirectly.

408. The benefitting regional customer groups for an investment region may change from trading period to trading period depending on the directional flow of electricity between connection regions. This is illustrated in the following example which is a variation of the simple three connection region illustration in clause 64:

Trading period	Flow pattern	Benefitting regional customer groups
1		Supply$_b$ Demand$_b$ Demand$_c$ Supply$_a$
2		Supply$_b$ Demand$_b$ Demand$_a$ Demand$_c$
3		Supply$_b$ Demand$_b$ Demand$_a$ Supply$_c$
4		Supply$_a$ Supply$_b$ Demand$_b$ Supply$_c$

3.5.2.4 Calculate simple method contributions (SMCs) for each regional customer group, investment region and trading period (step 4)

409. We use the inputs calculated in step 2 and the regional customer groups determined in step 3 to calculate the SMC for each regional customer group, investment region and trading period during CMP C. The SMC formulae are in clause 64(5) for the simple three connection region example in that clause.

410. For each regional customer group and investment region, we calculate the weighted average of SMC across all trading periods during CMP C. Each trading period can have a different weighting as determined by Transpower.[124] For the first simple method period we have weighted all trading periods equally.

411. The weighted average SMCs represents the generalised electricity flow state for all connection regions across the relevant simple method period.

3.5.2.5 Calculate regional NPB for each regional customer group and investment region (step 5)

412. The weighted average SMC calculated in step 4 for a regional supply group and investment region is the regional supply group's regional NPB for the investment region.

413. The weighted average SMC calculated in step 4 for a regional demand group and investment region multiplied by the demand factor is the regional demand group's regional NPB for the investment region. The demand factor scales up regional NPB for regional demand groups relative to regional NPB for regional supply groups.[125] The demand factor is, effectively, 1.67 (clause 64(4)).

3.5.3 Calculate simple method factors

414. A customer has a simple method factor (**SMF**) calculated for each regional customer group it is a member of (clause 61(2)).

415. The process we follow for these calculations is depicted in the illustration below and described in the following sections.

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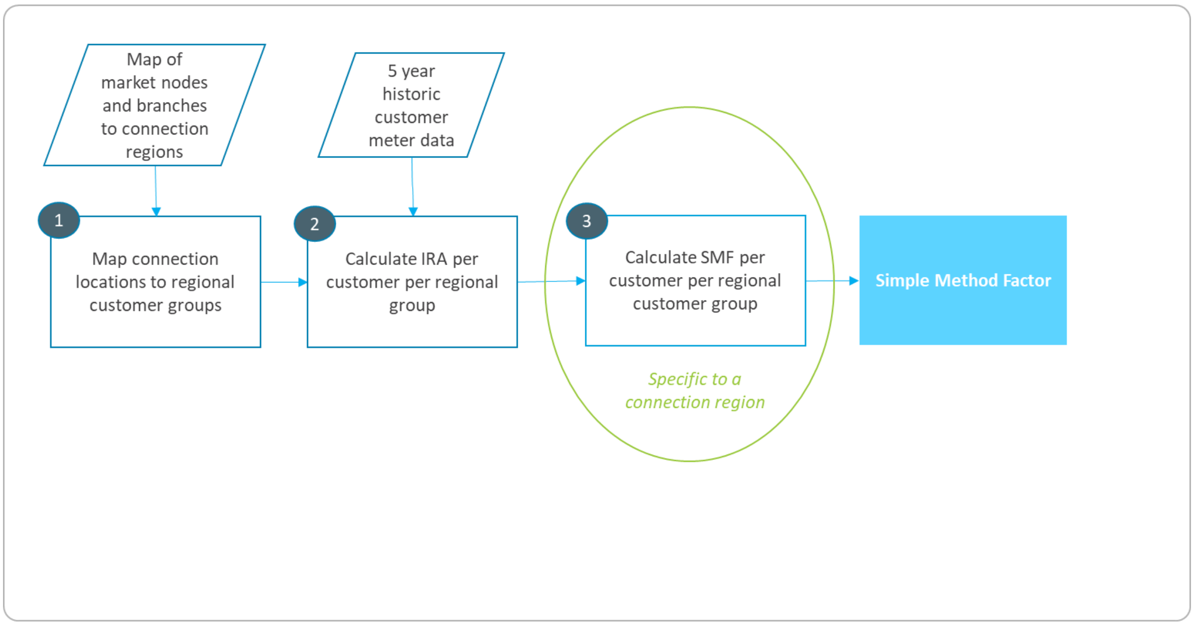
124 The ability to apply a different weighting to trading periods is included in the TPM to avoid the need to change the TPM in the event it is reasonable to apply different weightings in order to ensure BBI customer allocations are broadly proportionate to EPNPB (clause 64(4)). For example, if there are trading periods within CMP C that have no data available at the time of calculation, we can weight those trading periods as zero without a change to the TPM.

125 The Authority's rationale for the demand factor is in paragraphs 5.44 to 5.62 of its Transmission Pricing Methodology 2022: Decision paper.



3.5.3.1 Map connection locations to regional customer groups (step 1)

416. We map each market node to a connection location.

417. We map each connection location to a connection region using the map of market nodes to connection regions (see paragraph 401).

3.5.3.2 Calculate IRA per customer per regional customer group (step 2)

418. To calculate a customer's SMFs for the regional customer groups it is a member of, we must calculate their IRA for each regional customer group. Clauses 65 to 67 relate to the calculation of IRAs.

419. For BBIs under the simple method, the IRA for regional demand groups is mean historical annual offtake. The IRA for regional supply groups is mean annual historical injection (clause 65(4)).

420. IRAs are calculated based on injection or offtake (per trading period) over CMP C (clauses 65(10) and 65(11)).

421. New customers and recent customers (customers connected for less than two full capacity years during CMP C) have their IRAs estimated (but, for recent customers, taking into account any available information about their offtake or injection) (clauses 66 and 83(3)(a)).

3.5.3.3 Calculate SMF per customer per regional customer group (step 3)

422. We calculate each customer's SMF for each regional customer group by dividing the customer's IRA for the regional customer group by the total of all customers' IRAs for the regional customer group.

3.5.4 Calculate individual NPB and starting BBI customer allocations

3.5.4.1 Calculate individual NPB

423. A customer's individual NPB for the BBI is the sum of the of the regional NPB (for the relevant investment region) for each regional customer group of which the customer is a member multiplied by the customer's SMF for the group (clause 61(1)).

3.5.4.2 Calculate starting BBI customer allocations and BBCs

424. The starting BBI customer allocations for the BBI are calculated as each customer's individual NPB divided by the sum of all customers' individual NPBs (clause 43(1)).

425. A customer's BBC for the BBI is calculated by multiplying the BBI's covered cost by the customer's BBI customer allocation (clause 35(2)).

3.5.4.3 Apportioning between investment regions

426. If the BBI is in more than one investment region, the above calculations are done separately for each investment region, with an appropriate apportionment of the BBI's covered cost between the investment regions.

427. For this purpose, the allocation of grid assets to connection regions is relevant. Under clause 62(4)(f):

    a. where a grid asset is part of an HV to HV branch, the grid asset is allocated between the HV connection regions in proportion to the total electricity flows during CMP C

    b. where a grid asset is part of an HV to LV branch, the grid asset is attributed to the LV connection region

    c. where a grid asset is part of an LV to LV branch, the grid asset is allocated 50% to each LV connection region.

Chapter 4
Regions and factors for the simple method

4.1 Introduction

428. This chapter of includes the simple method modelled regions and the simple method customer allocation model.

429. The model includes the simple method factors (**SMF**), regional NPB (**RNPB**), demand adjustment factor (**F**) and BBI customer allocation (**CA**) values for the for the first simple method period.

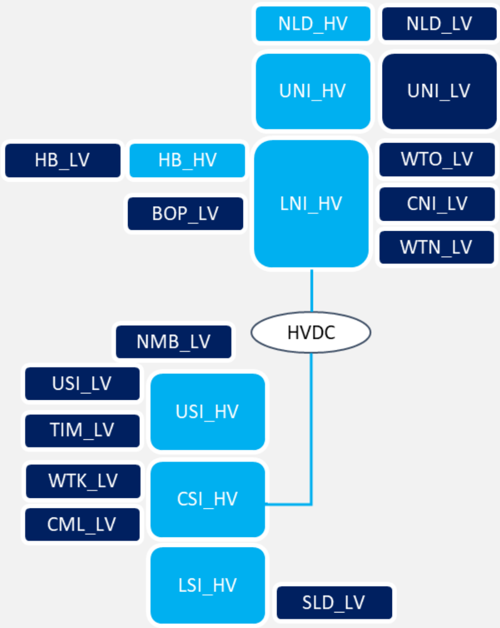
430. The assumptions book must contain the simple method modelled regions (clause 62(2)), the simple method factors for each regional customer group (clause 61(5)) and the regional NPB for each regional customer group with respect to each investment region (clause 64(1)).

431. This chapter will be updated with the simple method modelled regions and simple method customer allocation model for each subsequent simple method period prior to the commencement of that period.

4.2 Modelled regions

4.2.1 Table of regions

433. The table below contains the modelled regions for the first simple method period. These regions were determined using the process detailed in section 3.5.1 of chapter 3.



Region ID	Region Description
NLD_HV	Northland high voltage
UNI_HV	Upper North Island high voltage
LNI_HV	Lower North Island high voltage
HB_HV	Hawke's Bay high voltage
LSI_HV	Lower South Island high voltage
CSI_HV	Central South Island high voltage
USI_HV	Upper South Island high voltage
HVDC	HVDC link
NLD_LV	Northland low voltage
UNI_LV	Upper North Island low voltage
WTO_LV	Waikato low voltage
CNI_LV	Central North Island low voltage
WTN_LV	Wellington low voltage
HB_LV	Hawke's Bay low voltage
BOP_LV	Bay of Plenty low voltage
SLD_LV	Southland low voltage
CML_LV	Cromwell low voltage
WTK_LV	Waitaki low voltage
TIM_LV	Timaru low voltage
USI_LV	Upper South Island low voltage
NMB_LV	Nelson-Marlborough low voltage

4.2.2 HV connection regions

434. Transpower is not required to assess electricity flows over the entire high-voltage grid when determining connection regions (clause 62(5)(a)) and did not do so when we determined the initial boundaries to be assessed.

435. Instead, we considered the geographical and electrical similarity of the nodes in each region in order to determine the location we considered it possible a boundary could exist. We identified thirteen potential HV connection regions in the North Island and eleven potential HV connection regions in the South Island. We then tested these boundaries using the rules set out in section 3.5.1.1.

4.2.3 North Island HV connection regions test result

436. The following table summarises how the thirteen potential North Island HV connection regions were evaluated using the two tests described in 3.5.1.1 of chapter 3 and how that process resulted in the final four HV connection regions:

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
Northland	BRB-HPI	BRB_HPI1.1	Passes	Passes	Northland High Voltage (NLD_HV)
	HPI-MDN	HPI_MDN1.1			
North Shore	ALB-HEN-3	ALB_HEN3.1	Fails		Upper North Island High Voltage (UNI_HV)
	HEN-HPI	HEN_HPI1.1			
	HOB-WRD	HOB_WRD1.1			
North Isthmus	HEN-OTA	HEN_OTA.1	Passes	Fails	
	OTA-SWN	OTA_SWN.1			
	HOB-WRD	HOB_WRD1.1			
South Auckland	OTA-PEN 5&6	OTA_PEN5.1	Passes	Fails	
		OTA_PEN6.1			
	HEN-OTA	HEN_OTA.1			
	OTA-SWN	OTA_SWN.1			
	PAK-PEN-3	PAK_PEN3.1			
Upper North Island	BHL-WKM-1&2	PAK_WKM1.2	Passes	Passes	Lower North Island High Voltage (LNI_HV)
		PAK_WKM2.2			
	HLY-TAT-2	HLY_OTA2.1			
	DRY-HLY	DRY_HLY1.1			
	OHW-OTA 1&2	OHW_OTA1.1			
		OHW_OTA2.1			
	OTA-WKM 1&2	OTA_WKM1.1			

		OTA_WKM2.1			
WUNI	BHL-WKM-1&2	PAK_WKM1.2	Fails		
		PAK_WKM2.2			
	HLY-SFD	HLY_SFD.1			
	TMN-TWH	TMN_TWH1.1			
	OHW-WKM	OHW_WKM1.1			
	HAM-WKM	HAM_WKM.1			
	OTA-WKM 1&2	OTA_WKM1.1			
		OTA_WKM2.1			
Wairaki Ring North	HLY-SFD	HLY_SFD.1	Fails		
	TMN-TWH	TMN_TWH1.1			
	TKU-WKM 1&2	TKU_WKM1.1			
		TKU_WKM2.1			
	WRK-WKM	WKM_WRK1.1			
	THI-WKM	THI_WKM1.1			
	ATI-OHK	ATI_OHK.1			
	EDG-TRK 1 &2	EDG_TRK1.1			
		EDG_TRK2.1			
WRK Ring South	HLY-SFD	HLY_SFD.1	Fails		
	TMN-TWH	TMN_TWH1.1			
	TKU-WKM 1&2	TKU_WKM1.1			
		TKU_WKM2.1			
	WRK-WKM	WKM_WRK1.1			
	THI-WRK	THI_WRK1.1			

	OHK-WRK	OHK_WRK.1			
CNI	HLY-SFD	HLY_SFD.1	Fails		
	TMN-TWH	TMN_TWH1.1			
	TKU-WKM 1&2	TKU_WKM1.1			
		TKU_WKM2.1			
	RPO-WRK	RPO_WRK1.1			
Bunnythorpe	BPE-TKU 1&2	BPE_TKU1.1	Fails		
		BPE_TKU2.1			
	BPE-TNG	BPE_TNG1.1			
	BPE-BRK 1&2	BPE_BRK1.1			
		BPE_BRK2.1			
Wellington	BPE-PRT-1	BPE_PRM_HAY1.1	Fails		
	BPE-PRT-2	BPE_PRM_HAY2.1			
	BPE-TWT-1	BPE_TWC_LTN1.1			
	BPE-LTN-1	BPE_WIL1.1			
Hawkes Bay	RDF-WRK	RDF_WRK.1	Passes	Passes	Hawkes Bay High Voltage (HB_HV)
	WHI-WRK	WHI_WRK1.1			
Bay of Plenty	ATI-WKM	ATI_WKM.1	Fails		
	OHK-WRK	OHK_WRK.1			
Tarukenga	ATI-TRK 1&2	ATI_TRK1.1	Passes	Fails	
		ATI_TRK2.1			
	EDG-TRK 1&2	EDG_TRK1.1			
		EDG_TRK2.1			
	ATI-TRK 1&2	ATI_TRK1.1	Passes	Fails	

Western Bay of Plenty		ATI_TRK2.1			
	EDG-KAW-3	EDG_KAW3.1			

4.2.4 South Island HV connection regions test result

437. The following table summarises how the eleven potential South Island HV connection regions were evaluated using the two tests described in 3.5.1.1 of chapter 3 and how that process resulted in the final three HV connection regions:

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
Nelson	KIK-STK 1&2	KIK_STK1.1	Passes	Fails	Upper South Island HV (USI_HV)
		KIK_STK2.1			
North Canterbury	ISL-KIK	ISL_KIK1.1	Passes	Fails	
	CUT-WTT 2&3	ISL_KIK2.2			
		ISL_KIK3.2			
Top of South Island	ISL-KIK	ISL_KIK1.1	Passes	Fails	
	ISL-WTT 2&3	ISL_KIK1.2			
		ISL_KIK1.2			
Christchurch	ISL-TKB	ISL_TKB.1	Passes	Fails	
	ASB-ISL	ASB_ISL1.1			
	ASB-BRY	ASB_BRY.1			
	ISL-LIV	ISL_LIV.1			
Mid Canterbury	ISL-TKB	ISL_TKB.1	Passes	Fails	
	ASB-OPI 1&2	ASB_TIM_TWZ1.1			
	ISL-LIV	ASB_TIM_TWZ2.1			
		ISL_LIV.1			
USI	ISL-TKB	ISL_TKB.1	Passes	Passes	

	OPI-TWZ 1&2	ASB_TIM_TWZ1.3			Central South Island High Voltage (CSI_HV)
	ISL-LIV	ASB_TIM_TWZ2.3			
		ISL_LIV.1			
Upper Waitaki Valley	CML-TWZ 1&2	CYD_TWZ1.2	Fails		
	OHB-TWZ	CYD_TWZ2.2			
	OHC-TWZ	OHB_TWZ.1			
	BEN-TWZ	OHC_TWZ.1			
	ISL-LIV	BEN_TWZ.1			
		ISL_LIV.1			
Lower Waitaki Valley	CML-TWZ 1&2	CYD_TWZ1.2	Fails		
	LIV-WTK	CYD_TWZ2.2			
	ISL-LIV	LIV_WTK.1			
		ISL_LIV.1			
Lower South Island	CML-CYD 1&2	CYD_TWZ1.1	Passes	Passes	Lower South Island High Voltage (LSI_HV)
	NSY-ROX	CYD_TWZ2.1			
		NSY_ROX.1			
Central Otago	CYD-ROX 1&2	CYD_ROX1.1	Fails		
	NSY-ROX	CYD_ROX2.1			
Southland	INV-ROX 1&2	INV_ROX1.1	Fails		
	GOT-TMH 1&2	INV_ROX2.1			
		NMA_GOR_TMH1.2			
		NMA_GOR_TMH2.2			

4.2.5 LV connection regions

438. The following table summarises how the final thirteen LV connection regions were determined using the process described in 3.5.1.2 of chapter 3:

North Island LV connection regions				
LV Region	**Connected HV region**	**Interface**	**Interface branches**	**Test**
NLD_LV	NLD_HV	NLD_HV_NLD_LV	MDN_T5.T5, MDN_T6.T6	HV:LV no split required
		UNI_LV_NLD_LV	HEN_MPE1.3_HEN_MPE2.3	HV:LV split at minimum transfer branch
UNI_LV	UNI_HV	UNI_LV_NLD_LV	HEN_MPE1.3_HEN_MPE2.3	HV:LV split at minimum transfer branch
		UNI_HV_UNI_LV	OTA_T2.T2, OTA_T3.T3, OTA_T4.T4, OTA_T5.T5, PEN_T10.T10, PEN_T6.T6, HEN_T1.T1, HEN_T5.T5, HOB_T12.T12, ALB_T4.T4	HV:LV split at minimum transfer branch
		WTO_LV_UNI_LV	BOB_OTA2.1, BOB_OTA1.1	HV:LV split at minimum transfer branch
WTO_LV	LNI_HV	WTO_LV_UNI_LV	BOB_OTA2.1_BOB_OTA1.1	HV:LV split at minimum transfer branch
		LNI_HV_WTO_LV	HAM_T6.T6, HAM_T9.T9	HV:LV split at minimum transfer branch
		CNI_LV_WTO_LV	ARI_ONG.2	LV:LV split at minimum transfer branch
CNI_LV	LNI_HV	CNI_LV_WTO_LV	ARI_ONG.2	LV:LV split at minimum transfer branch

		LNI_HV_CNI_LV	BPE_T1.T1, BPE_T2.T2, BPE_T3.T3, NPL_T8.T8, SFD_T10.T10, SFD_T9.T9	HV:LV split at minimum transfer branch
		WTN_LV_CNI_LV	MGM_MST1.1	LV:LV split at minimum transfer branch
WTN_LV	LNI_HV	WTN_LV_CNI_LV	MGM_MST1.1	LV:LV split at minimum transfer branch
		LNI_HV_WTN_LV	HAY_T5.T5, HAY_T2.T2, HAY_T1.T1, WIL_T8.T8	HV:LV split at minimum transfer branch
BOP_LV	LNI_HV	LNI_HV_BOP_LV	KAW_T12.T12, KAW_T13.T13, EDG_T4.T4, EDG_T5.T5, TRK_T2.T2, TRK_T3.T3, KMO_T2.T2, KMO_T4.T4	HV:LV no further valid split
HB_LV	HB_HV	HB_HV_HB_LV	RDF_T3.T3, RDF_T4.T4	HV:LV no split required

South Island LV connection regions				
LV Region	**Connected HV region**	**Interface**	**Interface branches**	**Test**
SLD_LV	LSI_HV	LSI_HV_SLD_LV	GOR_T11.T11, GOR_T12.T12, INV_T1.T1, ROX_T10.T10, HWB_T6.T6, HWB_T4.T4	HV:LV no further valid split
CML_HV	CSI_HV	CSI_HV_CML_LV	CML_T5A.M5A, CML_T5B.M5B, CML_T8.M8	HV:LV no further valid split
WTK_LV	CSI_HV	CSI_HV_WTK_LV	WTK_T23.T23WTK_T24.T24	HV:LV split at minimum transfer branch
		WTK_LV_TIM_LV	STU_TIM.1	HV:LV split at minimum transfer branch
TIM_LV	USI_HV	WTK_LV_TIM_LV	STU_TIM.1	HV:LV split at minimum transfer branch
		USI_HV_TIM_LV	TIM_T5.T5, TIM_T8A.T8A, TIM_T8B.T8B, TIM_T8.T8	HV:LV split at minimum transfer branch
USI_LV	USI_HV	USI_HV_NMB_LV	ISL_T3.T3, ISL_T6.T6, ISL_T7.T7, WPR_T12.T12, WPR_T13.T13	HV:LV split at minimum transfer branch
		NMB_LV_USI_LV	DOB_T11.M11, DOB_T12.M12	LV:LV split at minimum transfer branch
NMB_LV	USI_HV	NMB_LV_USI_LV	DOB_T11.M11, DOB_T12.M12	LV:LV split at minimum transfer branch
		USI_HV_NMB_LV	KIK_T1.T1, KIK_T2.T2, STK_T7.T7	HV:LV split at minimum transfer branch

Note 1 Each of the separate LV connection regions is connected to only 1 HV connection region (clause 62(4)(d))

Note 2 The 'Test' column indicates how each boundary has been established as outlined in the following table:

HV:LV no split required	Determined by cl 62(4)(c). Where there is an HV to LV interface through only one interconnection branch.
HV:LV no further valid split	Determined by cl 62(4)(c). And subsequent testing concluded cl 62(4)(e) did not apply
HV:LV split at minimum transfer branch	Determined by cl 62(4)(d) where LV:LV boundaries are defined at the minimum transfer branch to ensure each LV connection region connects to only one HV connection region.
LV:LV split at minimum transfer branch	Determined by cl 62(4)(c) or (d). And subsequent testing created a further LV:LV boundary under cl 62(4)(e).

4.3 Simple Method Customer Allocation Model

439. The Simple BBI customer and regional allocations model is published alongside our decision on this assumptions book v1.0.[126]

[126] The Simple BBI customer and regional allocations model is online here.

Chapter 5
Adjustments to both low-value and high-value BBIs

5.1 Benefit factors

440. A new customer arriving is a BBC adjustment event.

441. Under clause 83(6), benefit factors are used to calculate new customers' starting BBI customer allocations for the Appendix A BBIs (the seven historical BBIs in Appendix A of the TPM).

442. Benefit factors are calculated for each Appendix A BBI, Appendix A customer and connection location at which the customer is (or was) connected. A customer's benefit factor for an Appendix A BBI and a connection location is the part of the customer's Appendix A allocation for the BBI attributable to the connection location per kWh of the customer's injection or offtake at the connection location over CMP D, or our estimate of what that injection or offtake would have been (clause 83(7)).

443. The relevant benefit factor(s) for comparator customer(s) (customers of the same type as the new customer) are used to calculate the new customer's starting BBI customer allocations for each of the Appendix A BBIs.

444. Because the benefit factors are based on the Appendix A allocations and are only calculated for the Appendix A customers, the benefit factors are static.

445. There are many benefit factors because each Appendix A customer has a separate benefit factor for each Appendix A BBI and each connection location at which the customer is connected. Accordingly, we have published the benefit factors with this assumptions book in a separate spreadsheet – see "BBC Assumptions Book benefit factors" at https://www.transpower.co.nz/our-work/industry/grid-pricing/transmission-pricing-methodology/tpm-benefit-based-investment.

Appendix A
Record of Transpower's application of the TPM: material decisions and departures

A1 Purpose

A.1 Chapters 2 and 3 of this assumptions book detail the assumptions, processes and methodologies we use when applying the TPM in order to calculate a customer's benefit-based charge.

A.2 To support consistency of our application of the TPM to BBIs over time, this appendix records where, for a particular BBI:

a. we have made a potentially material decision in our application of a clause of the TPM; and

b. we have made a material departure from the contents of chapters 2 and 3 of this assumptions book and the rationale for the departure.

A.3 The record is contained in the table below.

A2 Record of Transpower's application of the TPM: material decisions and departures

BBI	Date	TPM Clause	Summary of application	Related documents
CUWLP	15 September 2022	51(1)(b) and 52(1)(b)(ii)	Having considered paragraphs 307 to 309 of the assumptions book (v1.0), we decided to use clause 51 for CUWLP because: • modelled prices either side of the constraint were sensitive to modelling assumptions, and • the CUWLP circuits are part of the core grid, and • our modelling clearly demonstrated a significant price impact both upstream and downstream regions.	• TPM Decision paper: CUWLP starting BBI customer allocations • Record of application of the standard method: CUWLP starting BBI customer allocations Available on the TPM decisions webpage.

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