TRANSPOWER

BBI Assumptions Book v3

Workshop Webinar

20 May 2026

Agenda:

Intro – 5 min
Modelling using the Assumptions Book – 5 min
Generation updates – 10 min
Fuel cost and availability updates – 10 min
Wind and solar resource modelling – 5 min
Thermal operating costs – 5 min
Chapter 3 updates – 5 min
Conclusions and questions – 10 min

Intro

Some jargon

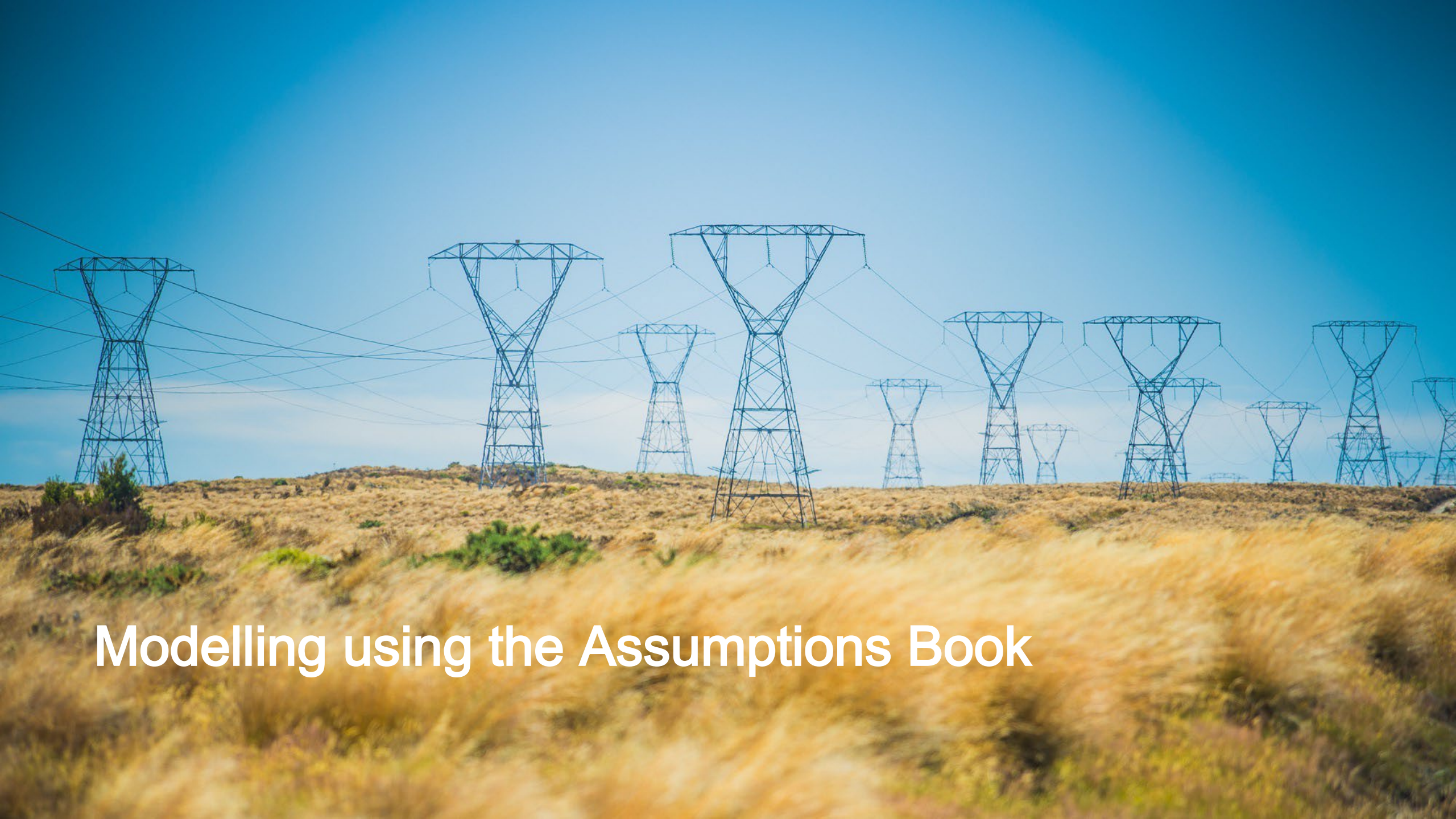
- Major Capital Project (**MCP**): Grid upgrade investments over $30m in value that are required for grid reliability or economic purposes
- Investment Test: An economic test that Transpower must apply when seeking Commerce Commission approval for an MCP
- Benefit Based Investments (**BBIs**): Major new transmission investments
- Benefit Based Transmission Charges (**BBCs**): Recover the cost of a BBI. Costs are allocated in proportion to a beneficiary's share of total expected benefits
- Market scenarios: Plausible electricity system futures based on MBIE's Electricity Demand and Generation Scenarios (**EDGS**)

What is the Assumptions Book?

- Contains detailed assumptions and methodologies that Transpower applies when calculating BBCs
- This workshop is focused on Chapter 2 of the Assumptions Book … which details modelling input assumptions used to calculate BBCs
- The same input assumptions are used when applying the Investment Test for MCPs
- Variations to Chapter 2 may be used for a specific project. These will generally be minor and will be consulted on

What does Assumption Book Chapter 2 not cover?

- Chapter 2 does not cover:
  - Project specific assumptions e.g. changes to the grid
  - Demand forecasts
- These assumptions are consulted separately for each project



Modelling using the Assumptions Book

Calculating benefits: the modelling end goal

Repeat for each market scenario

CALCULATING COSTS
- Over a 20 year horizon

Least cost generation expansion plan model → System capex costs

Least cost dispatch simulation model → System opex costs

Reliability model (for example) → Reliability costs

CALCULATING BENEFITS

Counterfactual - *no grid upgrade* - costs

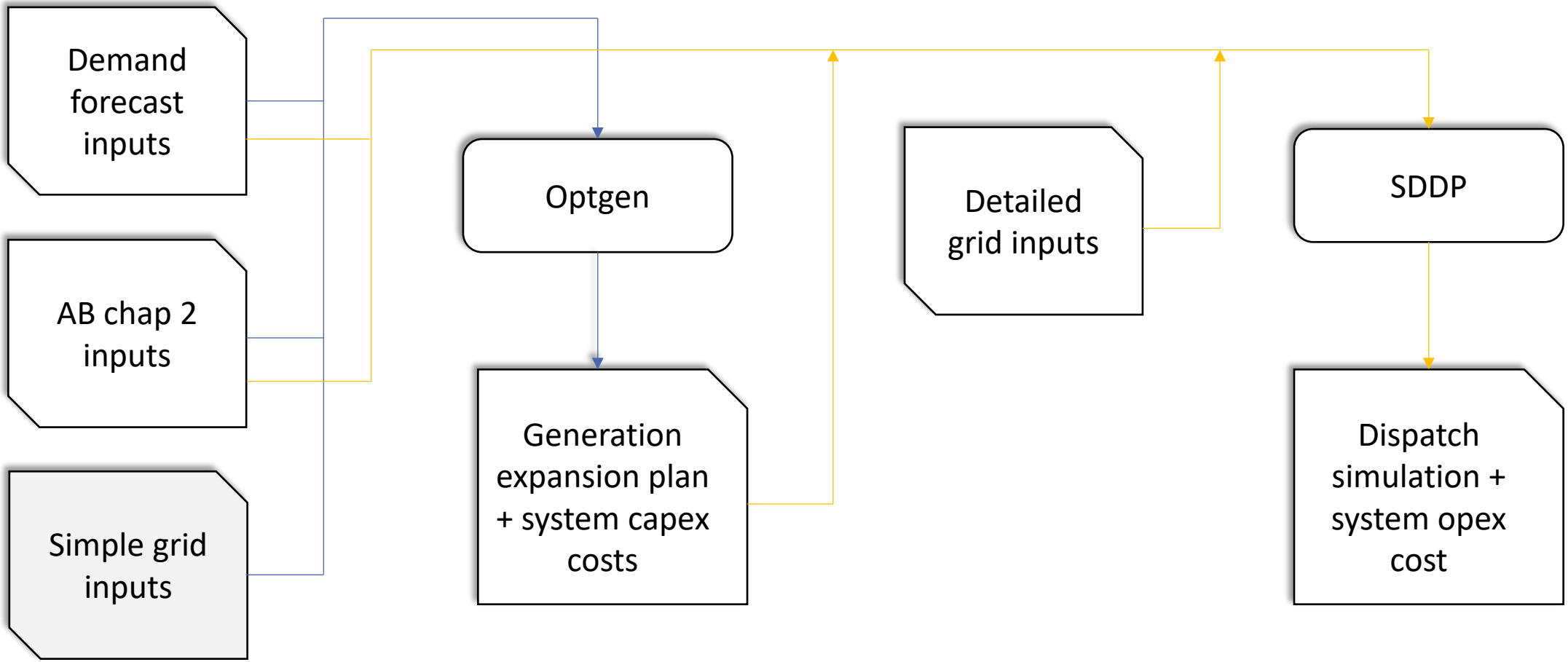
−

Factual - *with grid upgrade* - costs

=

Benefits

Modelling overview: Focusing on inputs

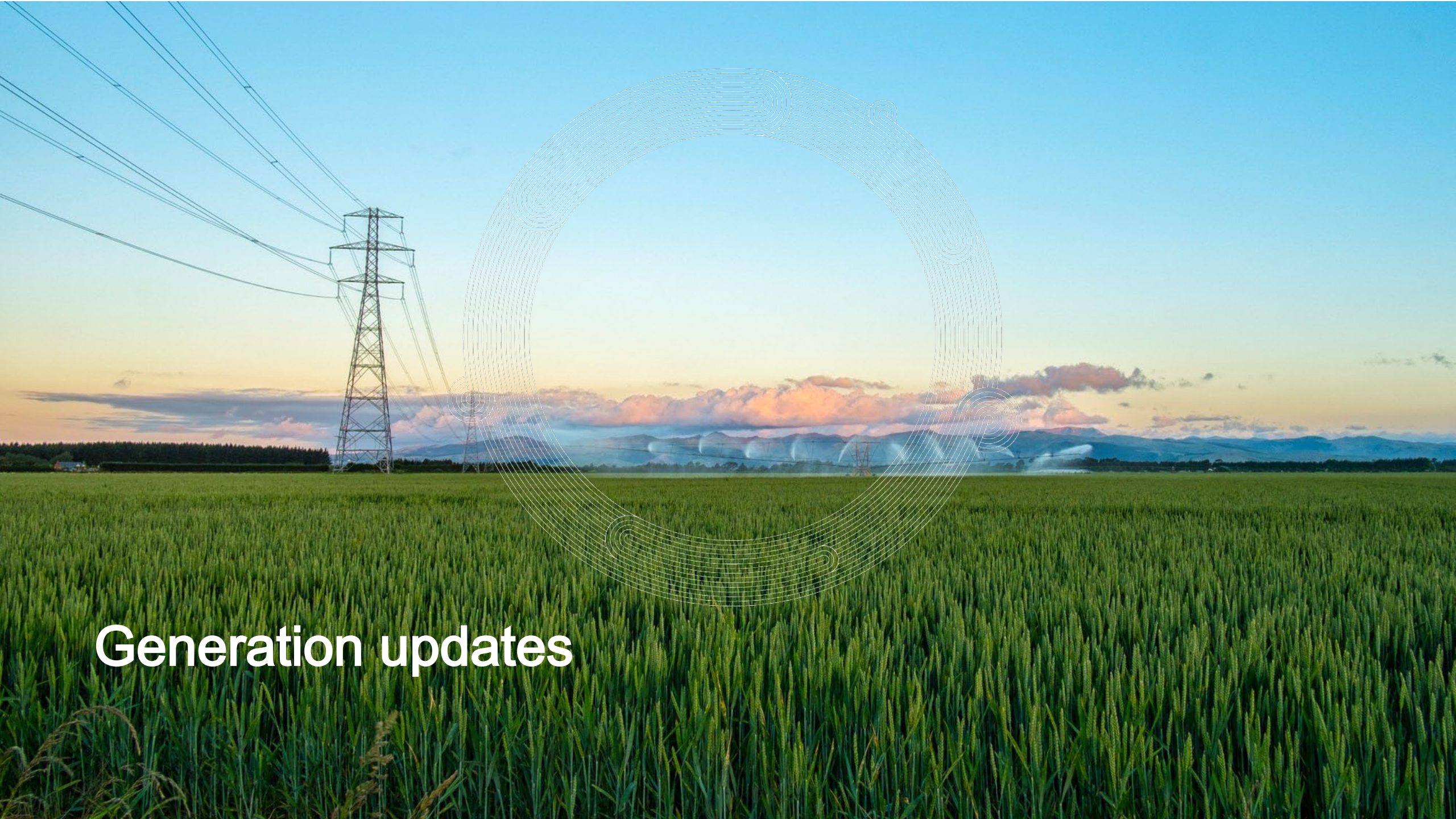


Market scenarios: Intro

- We calculate costs and benefits for up to five market scenarios
- Market scenarios are based on the MBIE's 2024 EDGS:
  - **Reference** : Current trends continue
  - **Growth** : Accelerated economic growth
  - **Constraint** : Slower economic growth
  - **Environmental** : Sustainable transition
  - **Innovation** : Improved technologies are developed

Market scenarios and the Assumption Book

- Market scenarios cover plausible futures for both electricity demand and supply
- Reasonable variations to MBIE's EDGS are allowed– the Assumption Book defines what these are for the supply side
- Many Assumption Book input assumptions vary across market scenarios
- This is to ensure our proposed grid upgrades are well tested against a diverse range of both demand and supply futures



Generation updates

Generation updates

Existing generation

+

Candidate generation
("the stack")

Existing generation

All plants commissioned as of 1 Jan 2025 (*ABv2: 2023*)

Capacities derived from:

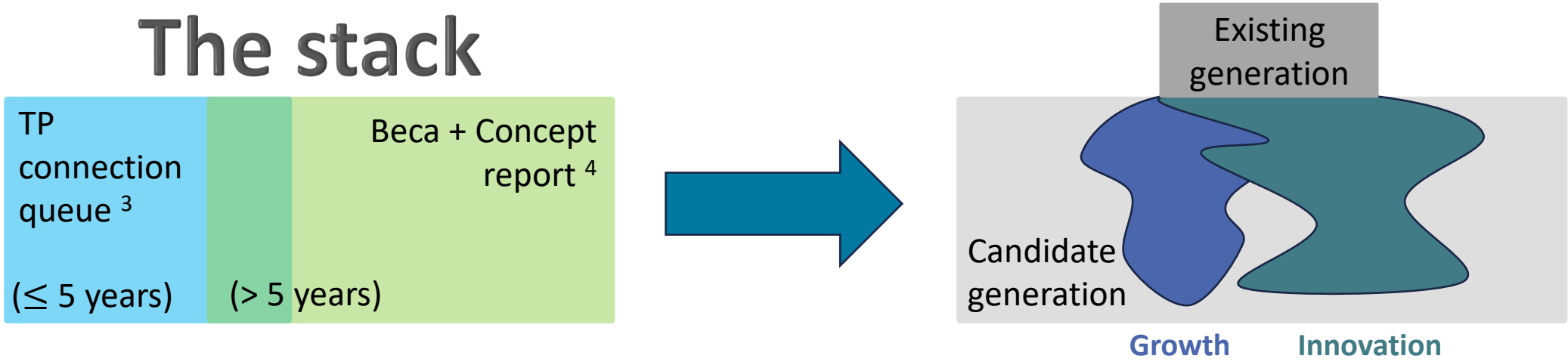
- System Operator's 2025 *Security of Supply assessment* [1]

  or

- em6 generation data [2]

1 Security of Supply Assessment | Transpower
2 https://app.em6.co.nz/generation

Candidate generation



[3] What's the latest with grid connections? | Transpower

[4] 2025 Generation Stack Report | Beca and Concept (2025). Commissioned by Transpower.

Cost and timeline

- **Updated cost assumptions**
  - Capital and O&M refreshed
  - Updated cost decline assumptions
  - Beca and Concept Report [4]

- **Improved project development timelines**
  - 1 yr development lag for new generation projects
  - Geothermal construction periods shortened to 3 yrs

[4] 2025 Generation Stack Report | Beca and Concept (2025). Commissioned by Transpower.

Candidate BESS

$$\Sigma \text{ BESS} = p \times \Sigma \begin{pmatrix} \text{wind} \\ + \\ \text{solar} \end{pmatrix}$$

p is EDGS-dependent %

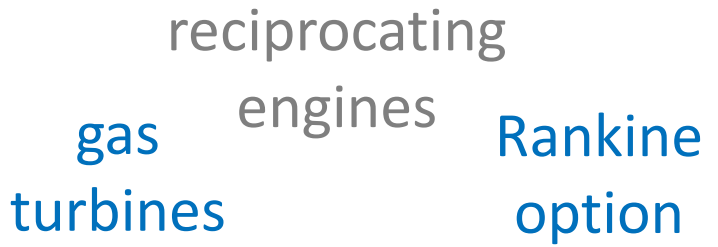
14 Grid Zones

8 North Island

6 South Island

Candidate Thermal

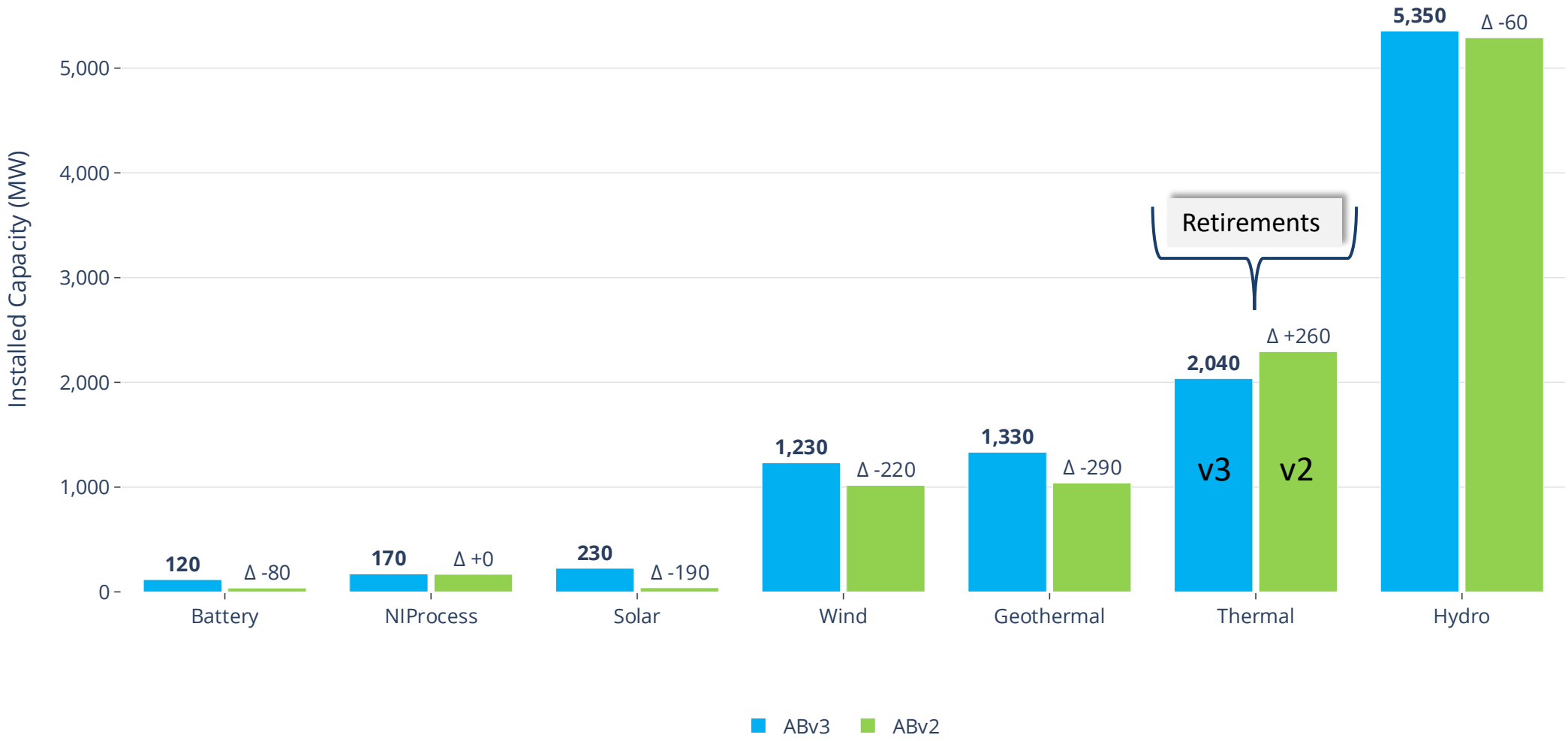
- **Broader thermal build options**



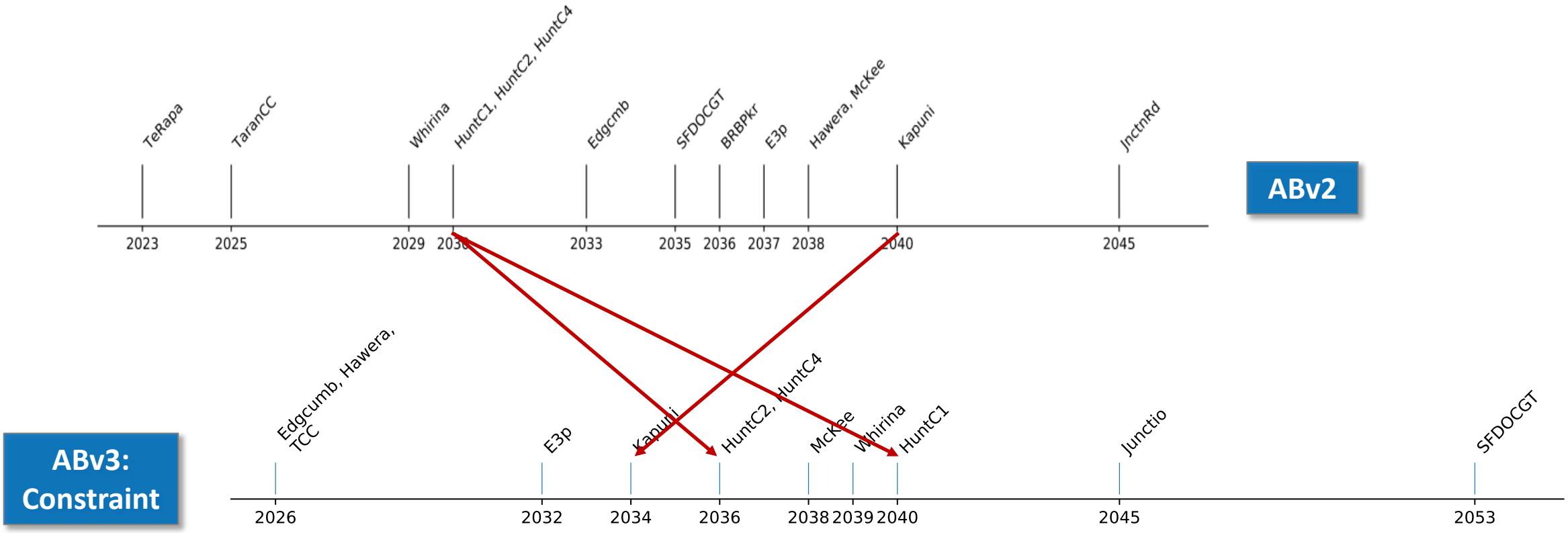
- Expanded multi-fuel assumptions
  - up to 3 fuels / plant

- Updated cost and performance data

Existing generation: 2025 vs 2023

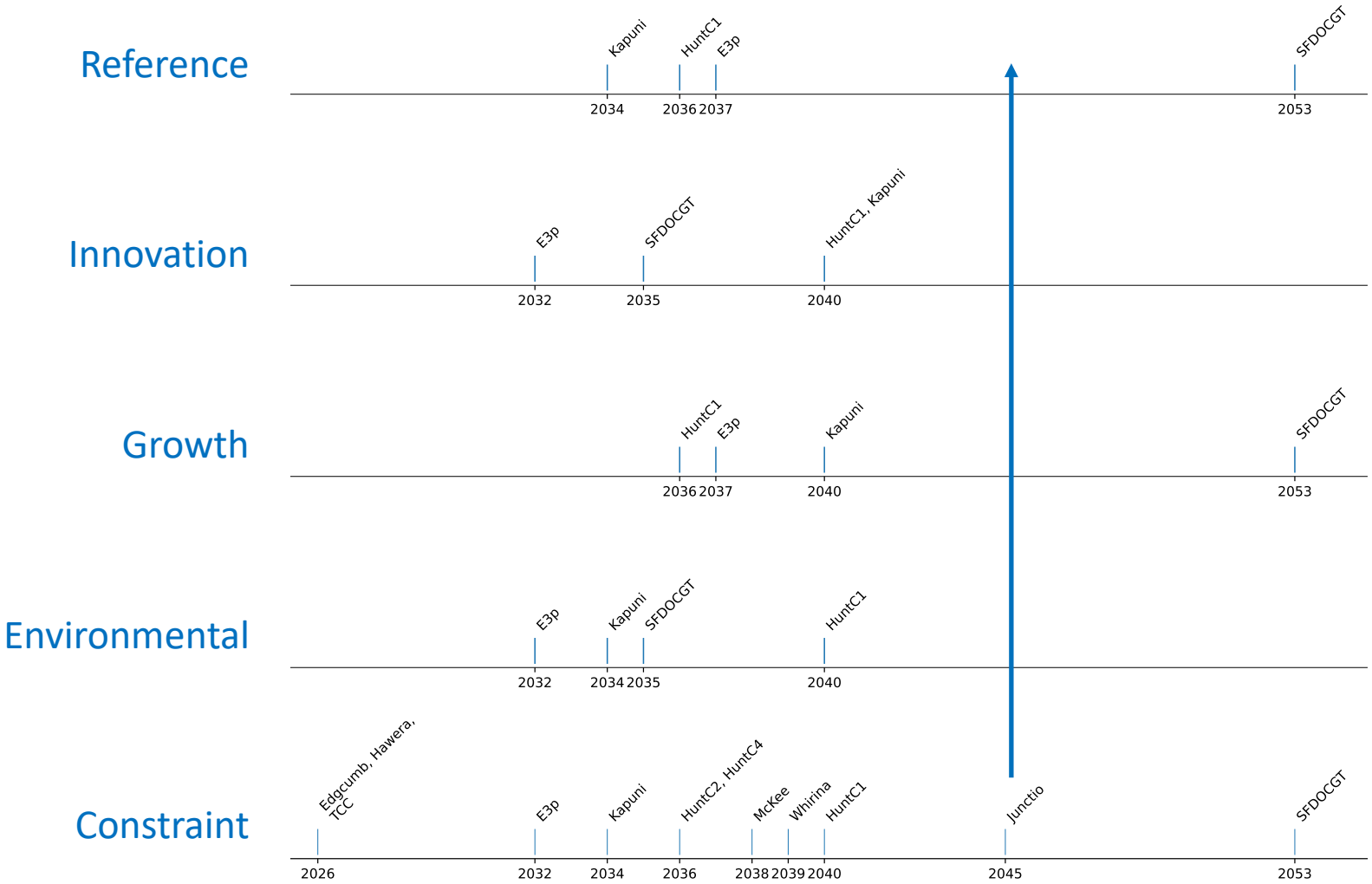


Thermal retirements

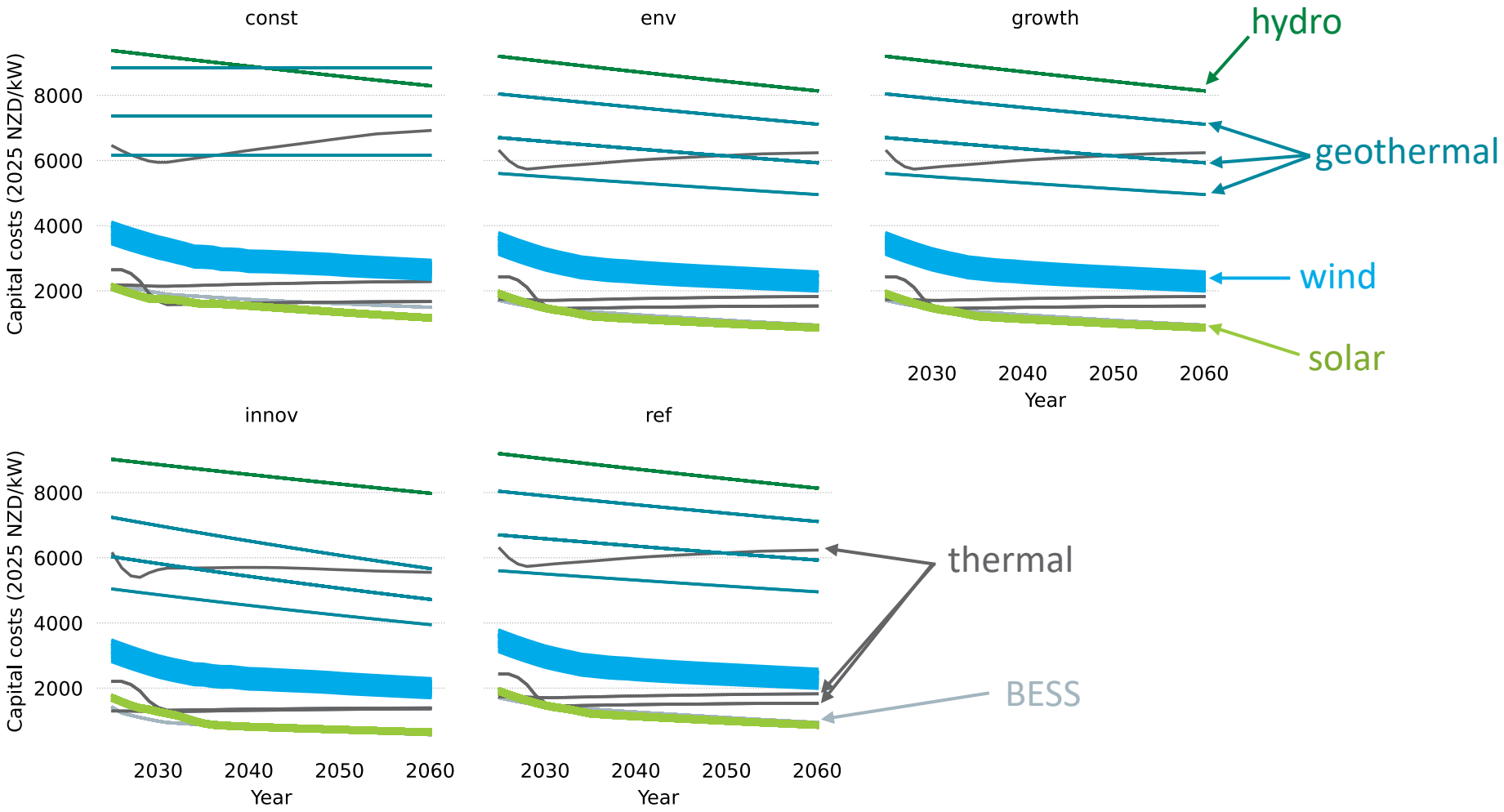


updated from recent market information

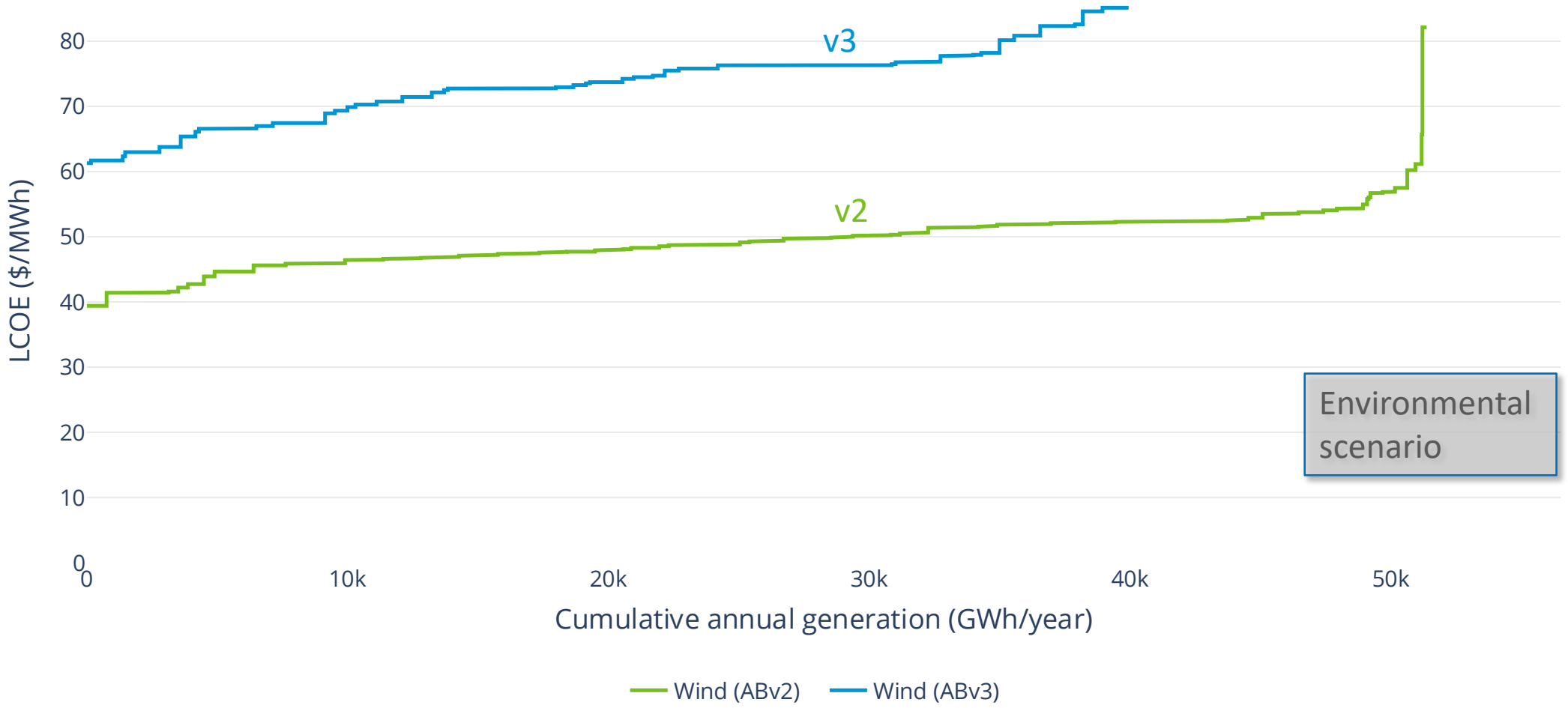
Thermal retirements: EDGS variation



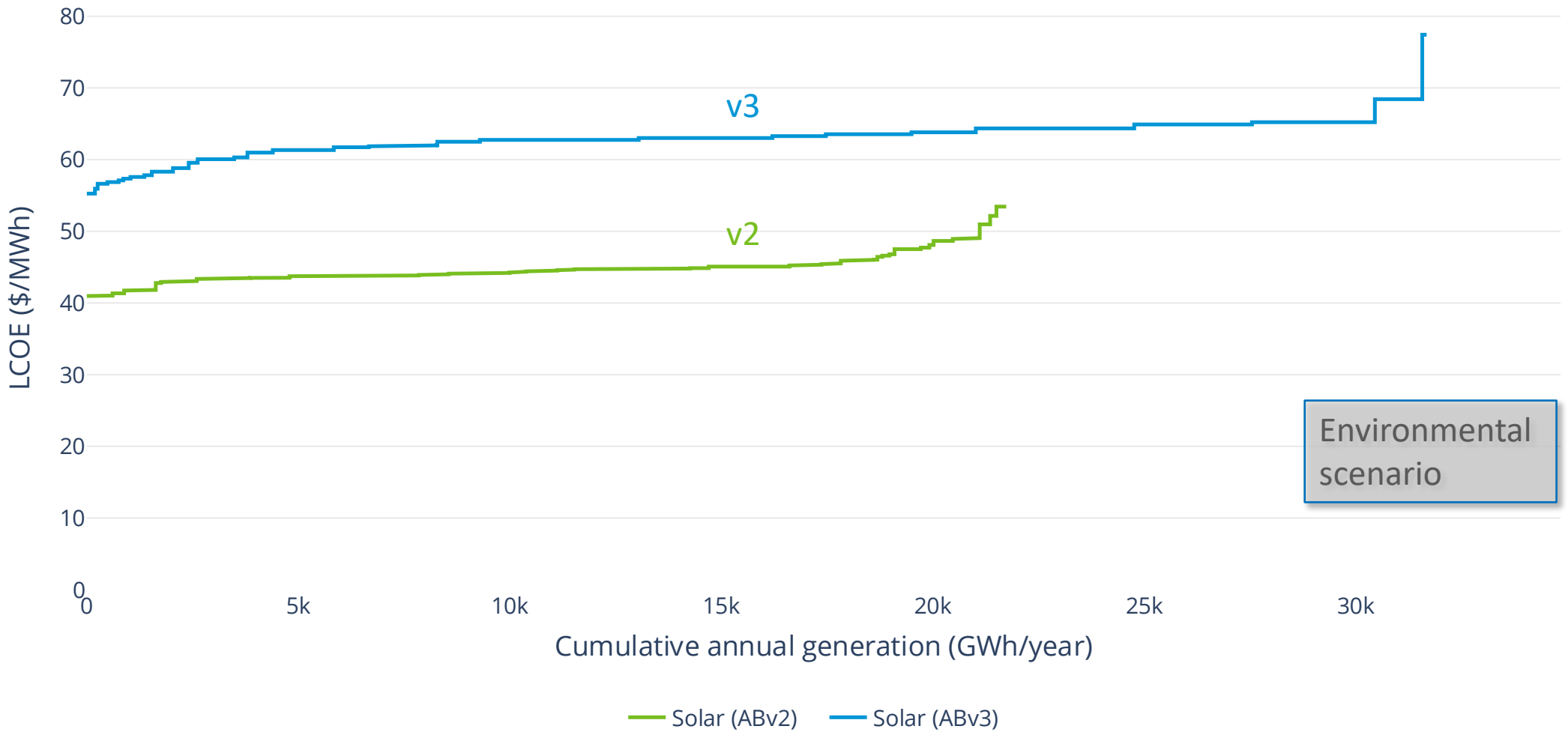
Cost declines



Levelised cost of energy: Wind 2035



Levelised cost of energy: Solar 2035



Fuel cost and availability updates

Change highlights – gas availability

- Natural gas supply was unconstrained in ABv2.
- **Gas supply is restricted in ABv3 with multiple supply tranches.**
  - To reflect scarcity of domestic natural gas supply we restrict natural gas availability for power generation.
    - Availability = production forecast[1] + contingent resource development – non-power generation consumption[2]
  - Ahuroa gas storage reservoir is modelled allowing consumption to be offset from production.
  - LNG is assumed to be available for the Reference and Growth scenario from 2028.
  - Small volumes of biomethane are available in the Environmental scenario from mid 2030s.

1. MBIE 2025 production forecast
2. Estimated from scenario fuel switching assumptions

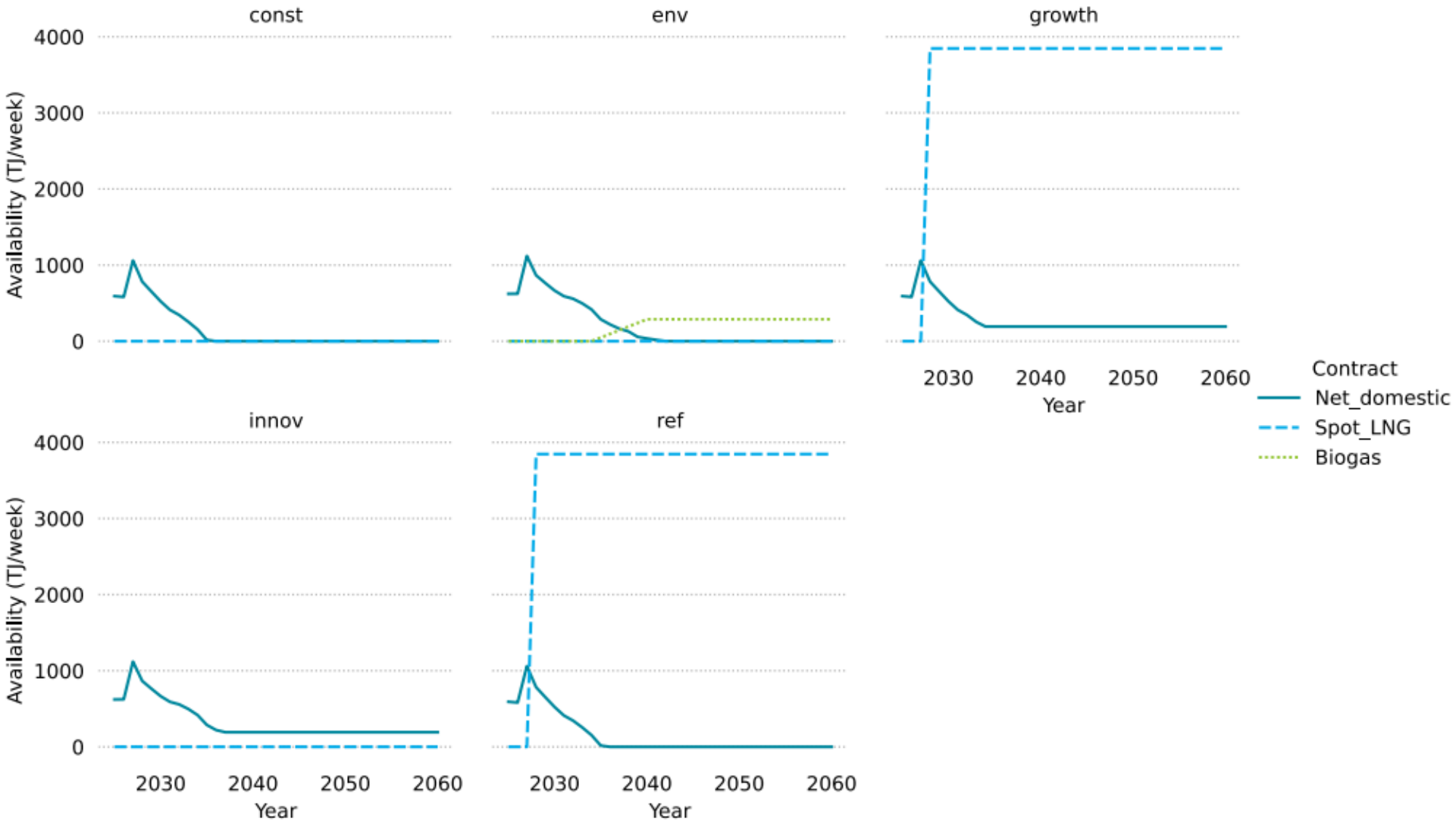


Figure 12: Gas and biofuel contract availability[57]

Other fuel availability

- Biomass pellets are available for use in Rankine units for the Environmental and Innovation scenarios.
- In the Environmental scenario diesel is available until 2040. In other scenarios diesel supply is unrestricted. Diesel can only be consumed in peaker plants.
- Biodiesel is available in the Environmental scenario from the mid 2030s.

Change highlights – fuel costs

- Imported fuel costs (diesel, LNG, coal) are based on the IEA's STEPS scenario. These commodity prices are adjusted to give delivered costs for a power plant.
- For domestic natural gas we assume a 2% p.a. increase in production costs as the size of the industry reduces.
- Biofuel costs are based on a range of sources.

- **Note that price discovery for fuels occurs within the SDDP model**

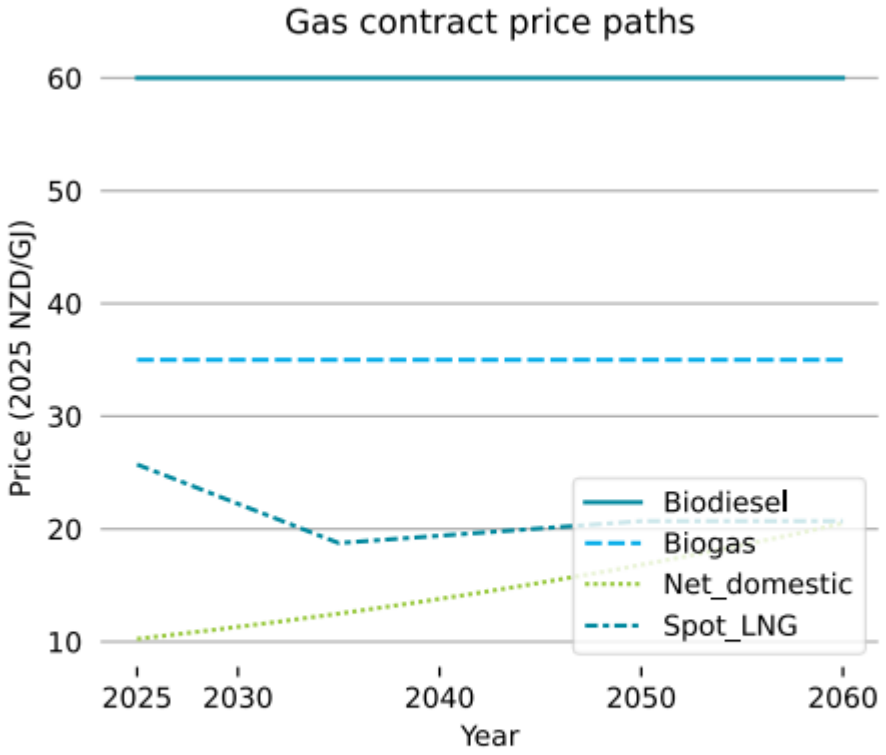


Figure 11: Gas and biofuel contract price paths

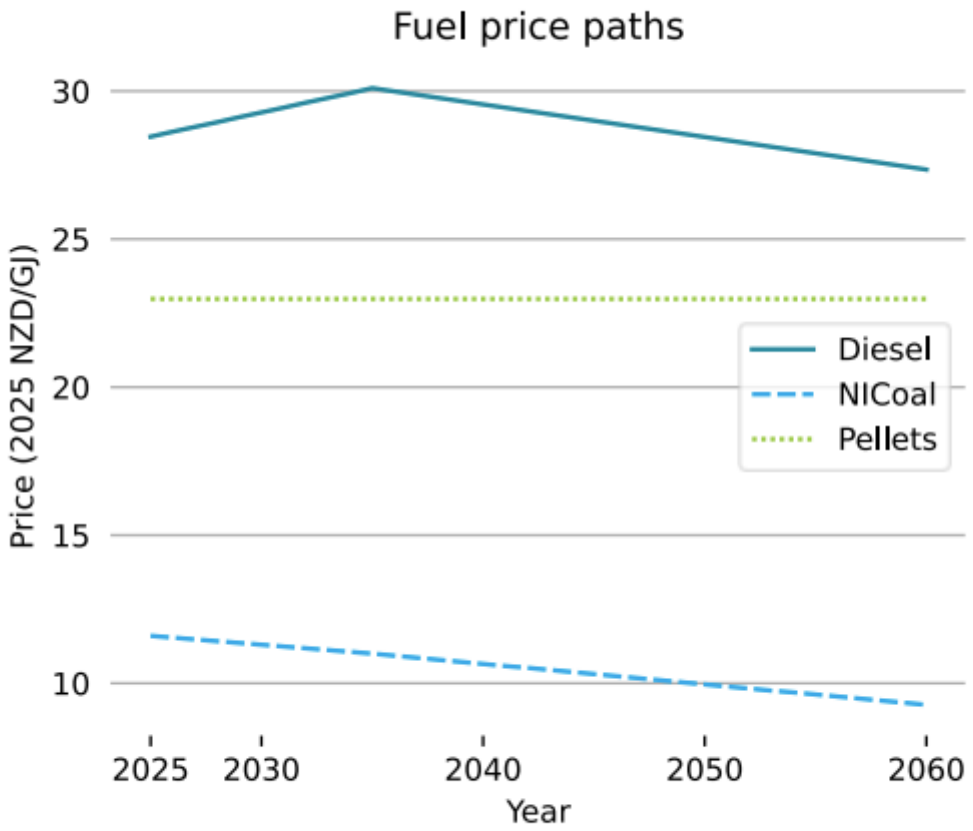
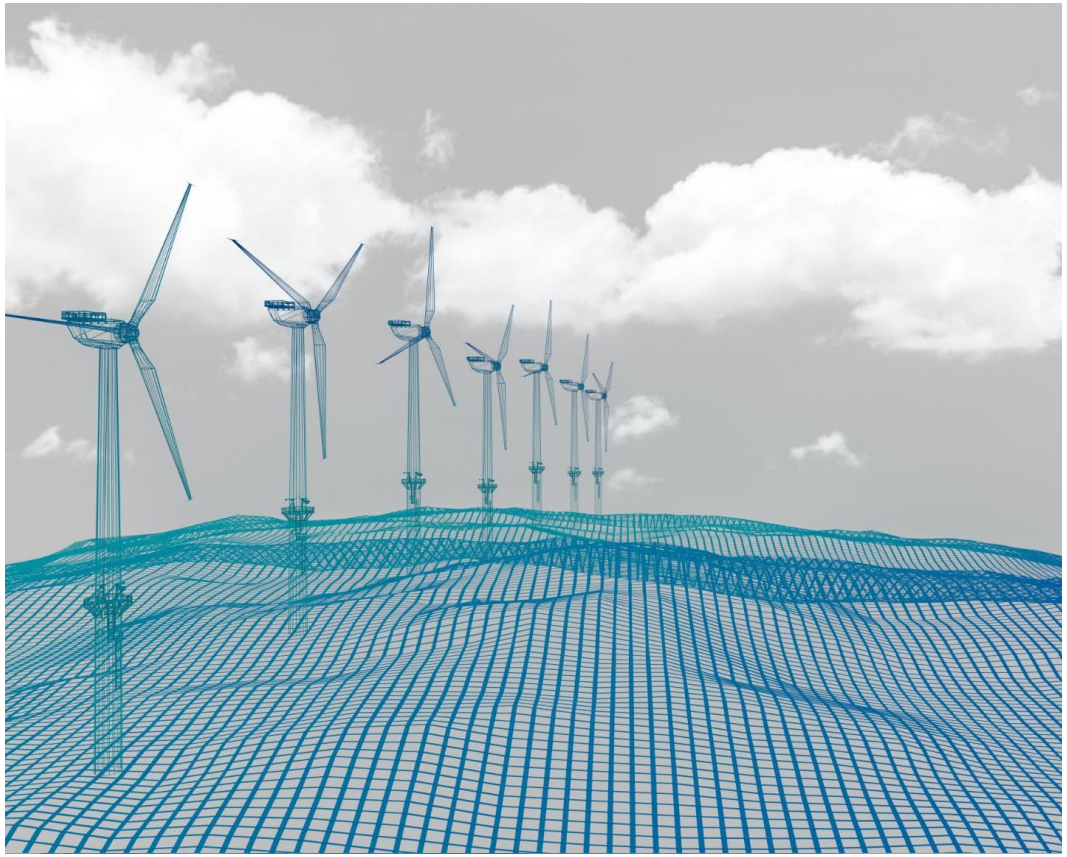


Figure 10: Price paths for Coal, Diesel, and Pellets

Wind and solar resource modelling

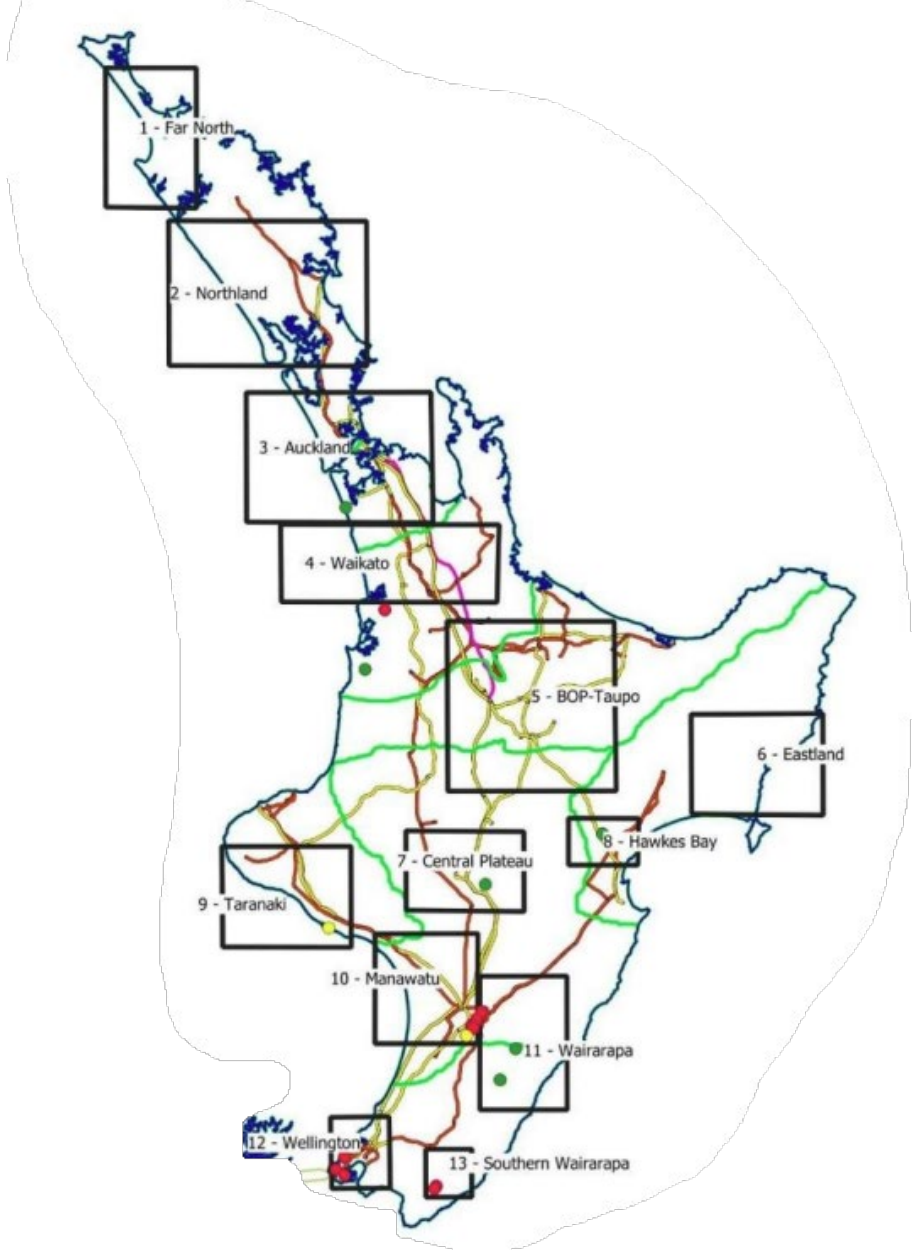
Renewable Resource Modelling – Time Series Lab

- **Key change:** We have shifted renewable resource modelling to PSR's Time Series Lab.
- **Unchanged:** Renewable Ninja and NASA MERRA2 database.
- Historical records for 1980 – 2024.
- Synthetic scenarios.



Wind Modelling

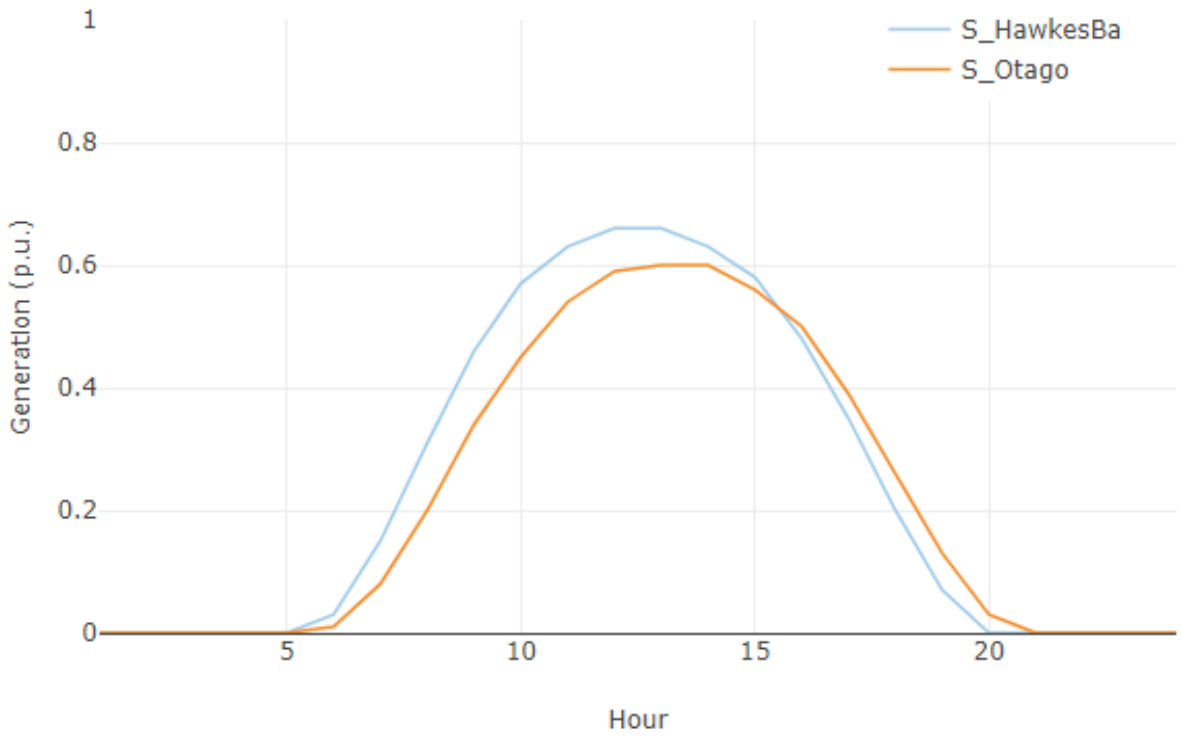
- Renewable Ninja's Virtual Wind Farm (VWF) model.
- We use target capacity factors to scale the output of the wind farm based on location.
  - MBIE/Roaring40s Wind Generation Stack.



Source: MBIE - Wind Generation Stack update V2.0_Final_30 June 2020

Solar Modelling

- **Key change:** Regional approach to capacity factors.
- Global Solar Energy Estimator (GSEE) model.
- Capacity factors between 20 - 25%.



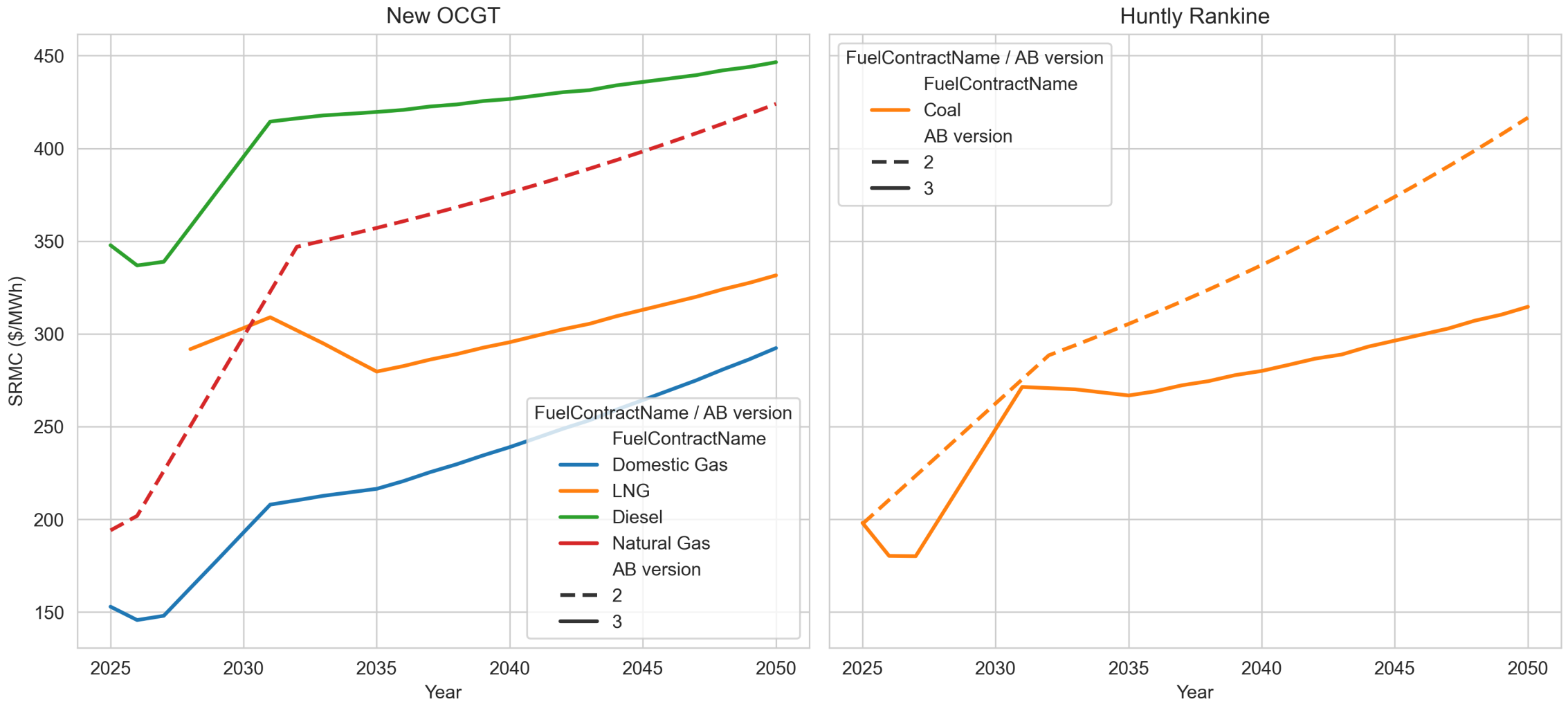
Thermal operating costs

Thermal operating costs

- System opex costs – estimated by SDDP – are heavily influenced by thermal operating costs (**SRMCs**)
- SRMCs in turn depend on plant efficiencies, fuel costs, carbon costs, variable opex costs and fuel availability.
- Our updates have changed all of these factors

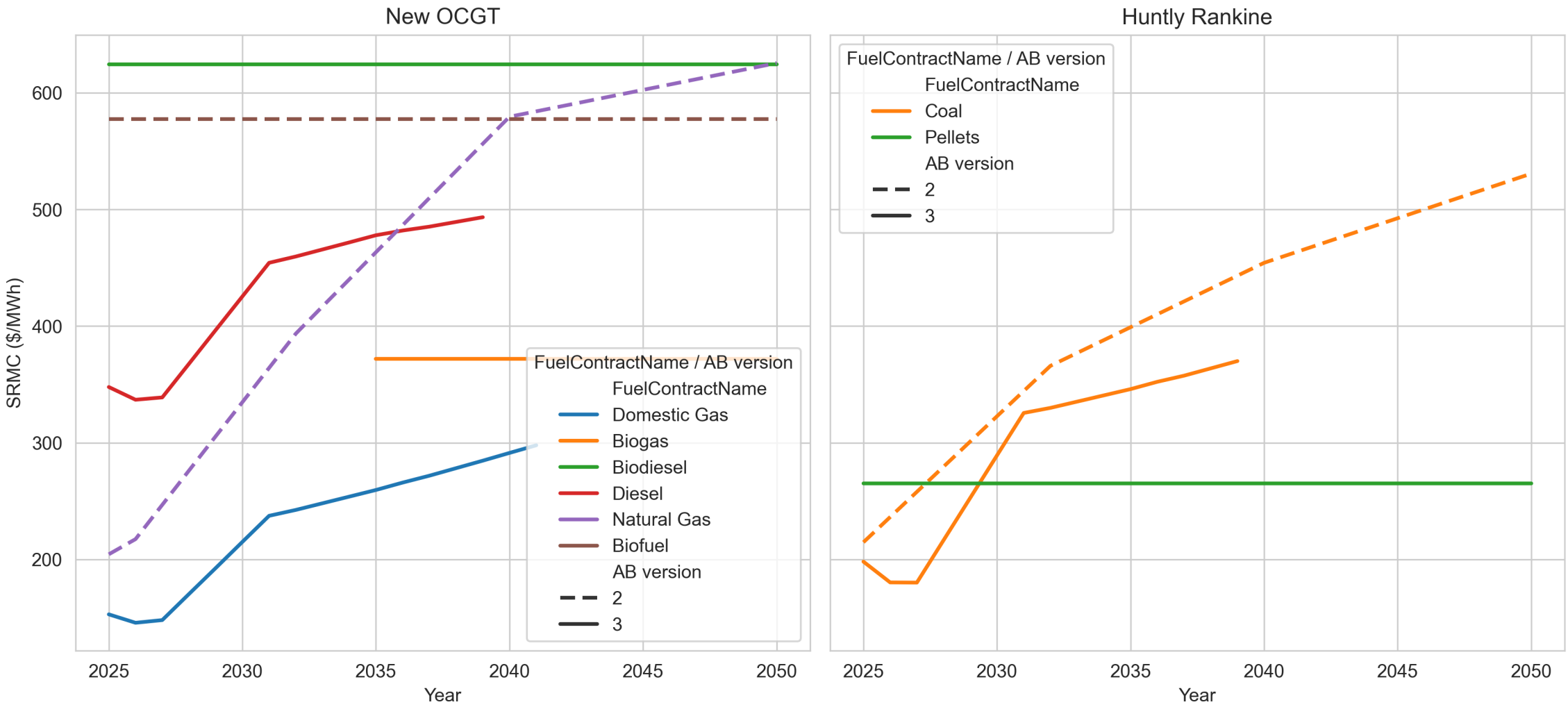
SRMCs for the Growth Scenario

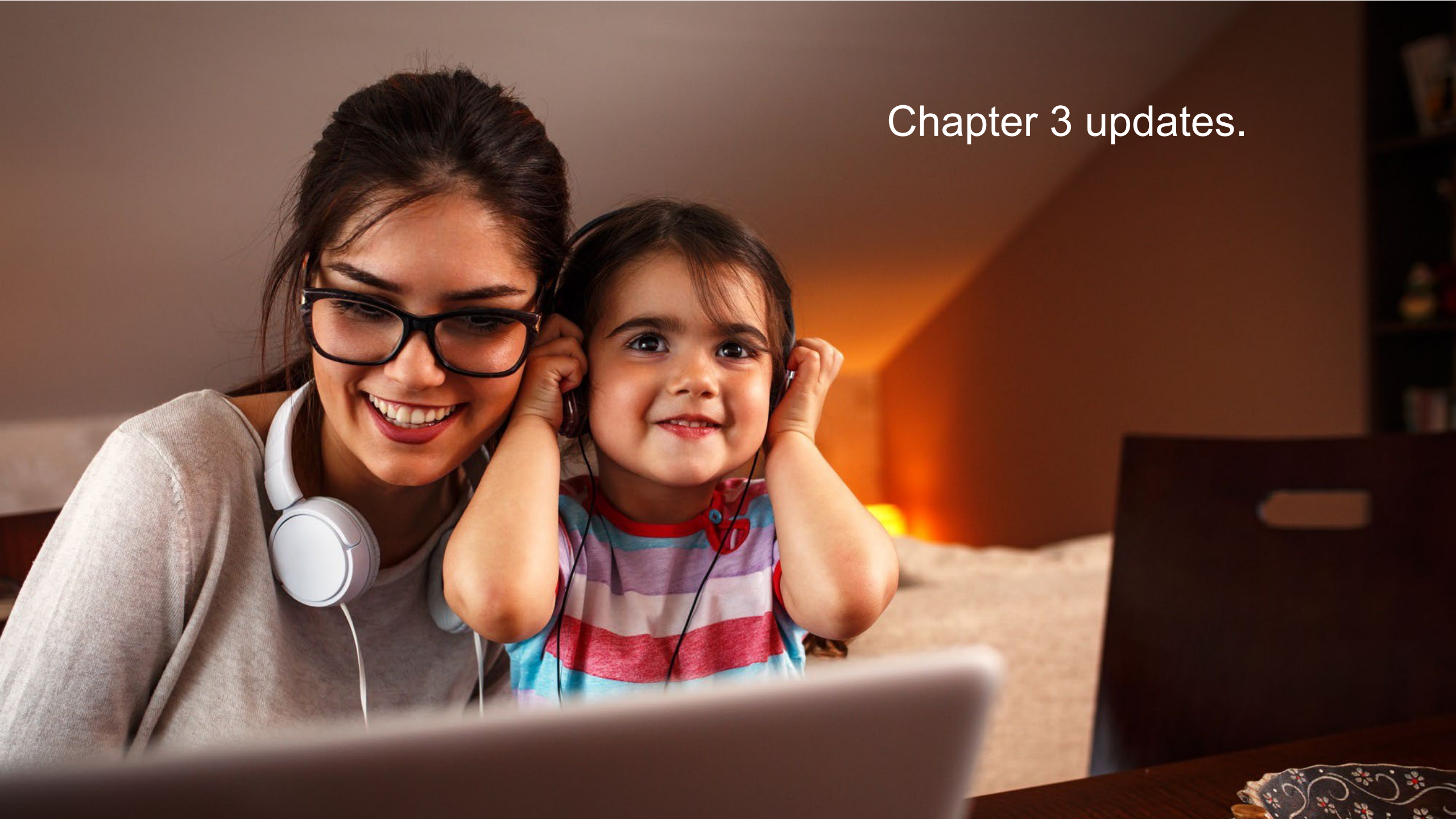
Costs are real and in $2025



SRMCs for the Environmental Scenario

Costs are real and in $2025



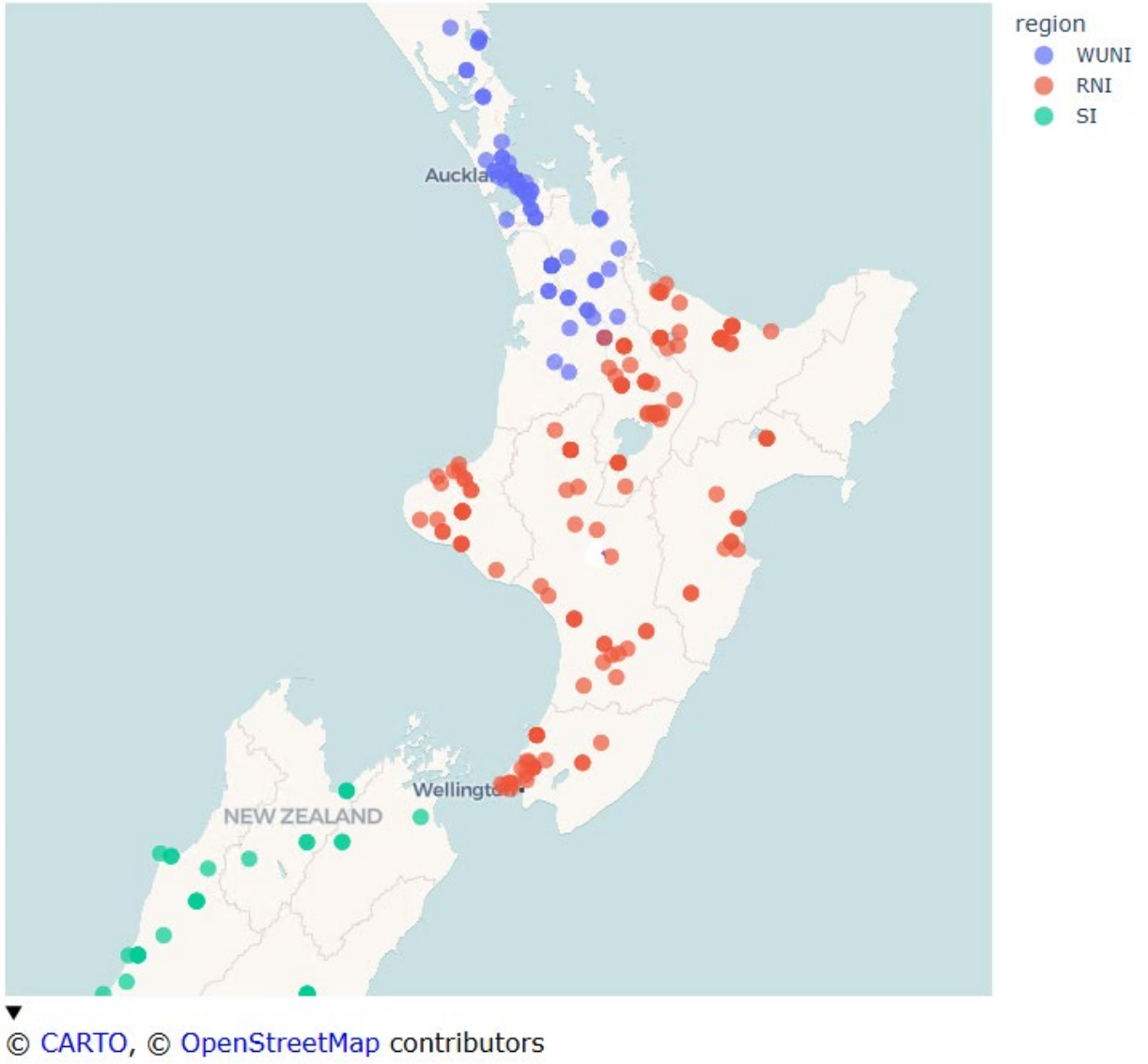

Chapter 3 updates.

Amalgamation of Potential Regional Customer Groups

- Final Regional Customer Groups can now only be formed from Potential Regional Customer Groups (PRCG) from the same Modelled Region
- Now the PRCGs with the closest ratio of Net Private Benefit to historical injection/offtake are amalgamated first.

Context: Modelled Regions

- Groups of GXP/GIP where the modelled price or quantity changes are in the same direction.
- Separated by modelled constraints



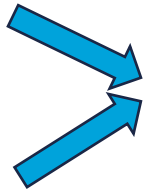
Regional Customer Groups

- Demand
  - Industrial
  - Non-Industrial
- Supply
  - storage hydro
  - wind
  - solar,…

New Amalgamation Method

The most similar PRCGs are amalgamated

Generation group	PVMRNPB ($m or GWh)	IRA (GWh)	PVMRNPB /IRA ratio	Percentage of previous
wind gen	60	20	3.00	
storage hydro gen	100	40	2.50	83%
run of river hydro gen	220	100	2.20	88%
solar gen	35	20	1.75	73%
thermal gen	10	30	0.33	19%



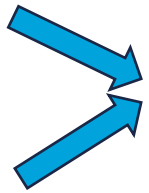
Generation group	PVMRNPB ($m or GWh)	IRA (GWh)	PVMRNPB /IRA ratio	Percentage of previous
wind gen	60	20	3.00	
hydro gen	320	140	2.29	76%
solar gen	35	20	1.75	75%
thermal gen	10	30	0.33	19%

repeat until no pairs are closer than 80%

Old Amalgamation Method

The most similar PRCGs end up in different RCGs

Generation group	PVMRNPB ($m or GWh)	IRA (GWh)	PVMRNPB /IRA ratio	Threshold to join
wind gen	60	20	3.00	2.4
storage hydro gen	100	40	2.50	
run of river hydro gen	220	100	2.20	1.76
solar gen	35	20	1.75	1.4
thermal gen	10	30	0.33	



Generation group	PVMRNPB ($m or GWh)	IRA (GWh)
wind and storage hydro gen	160	60
run of river hydro gen	220	100
solar gen	35	20
thermal gen	10	30

Just a single pass

Conclusion and questions

Conclusions

- Key updates for version 3:
  - Existing and future generation stack
  - Fuel costs
  - Renewable resource profiles
  - Carbon and deficit costs (… see the consultation for details)
- Consultation closes 29 May
- For more information: Assumptions book | Transpower
- Follow up questions grid.investments@transpower.co.nz
- Thanks for attending!

Questions

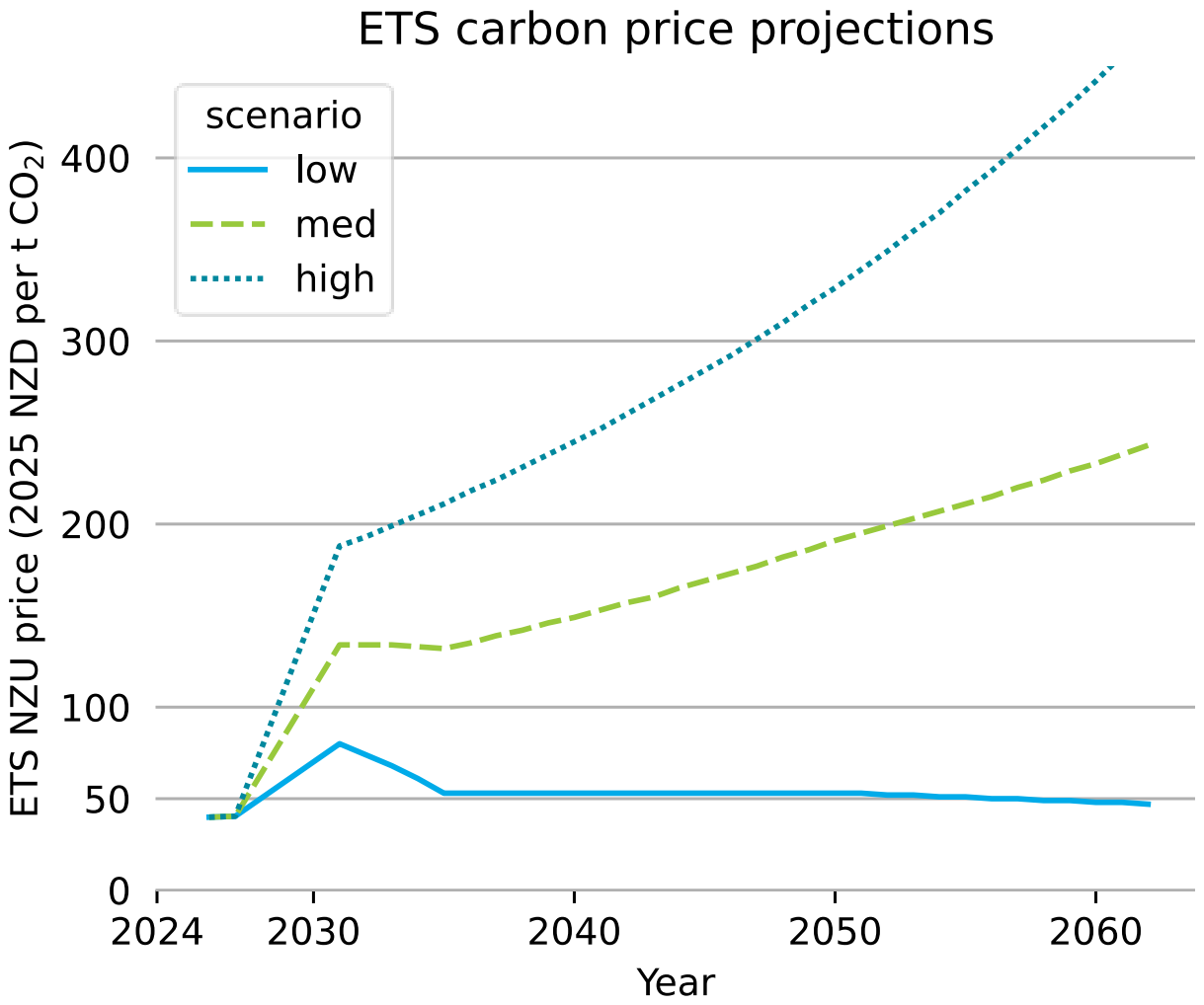
Thank you

TRANSPOWER.CO.NZ

Back-up slides

Carbon costs

- Short term carbon costs based on NZU prices and ASX futures
- Long term carbon costs based on emission values published by the Treasury

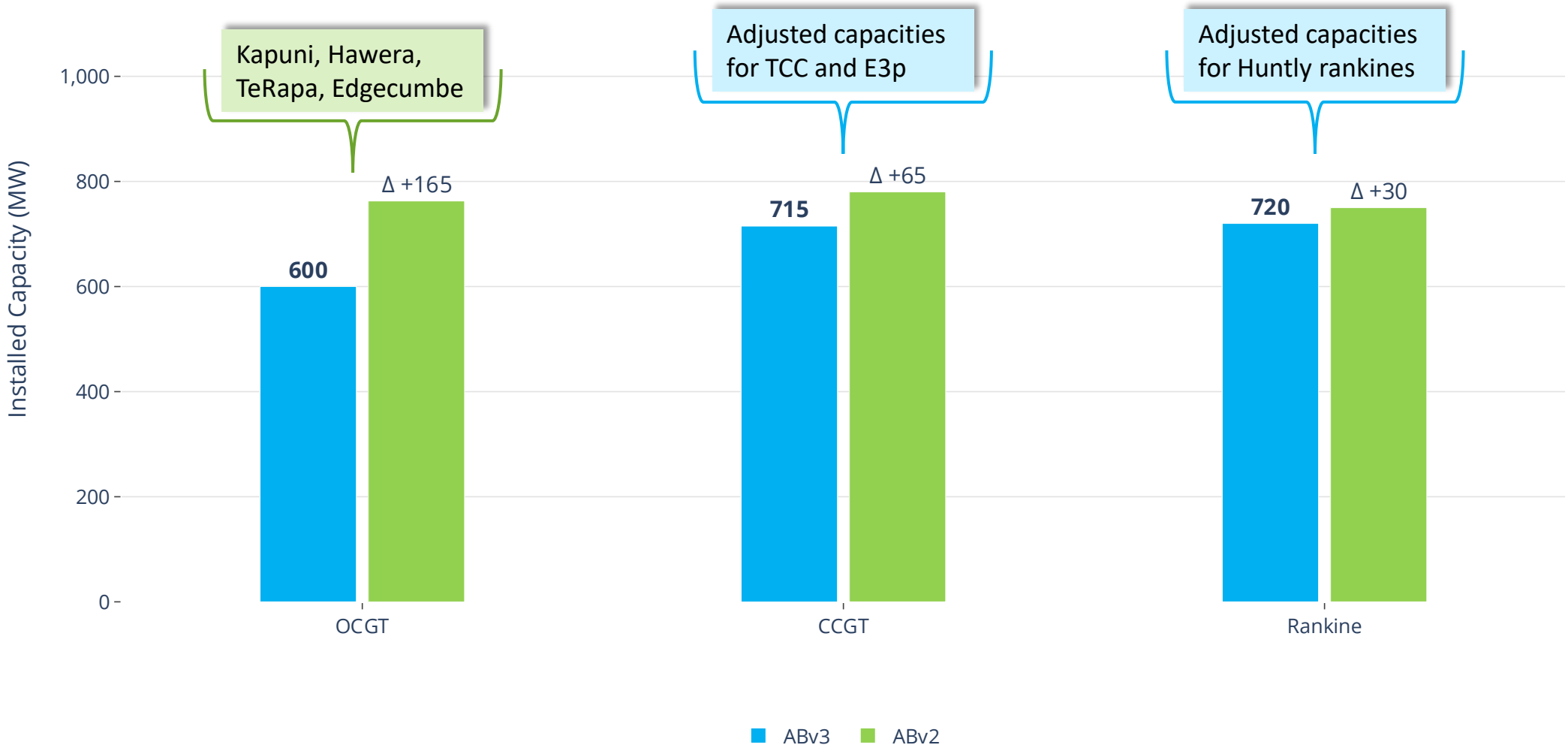


Deficit costs

Deficit as a proportion of Island hourly demand		Cost (2025$/MWh
Constraint, Growth, Reference and Environmental market scenarios	Innovation market scenarios	
First 2.25% of demand	First 2.75% of demand	700
Between 2.25% and 4.5% of demand	Between 2.75% and 5.5% of demand	950
Between 4.5% and 9.5% of demand	Between 5.5% and 10.5% of demand	4000
Greater than 9.5% of demand	Greater than 10.5% of demand	21,000

Existing and committed (2025) generation

Existing and committed thermal generation



Candidate generation