Appendix A

Detailed Options Methodology

Ramp Management (1A) | Pan-European Day Ahead Model

Ramp Management

Option Definition

Codify existing ramp rates (100MW/min) within interconnector agreements into the Grid Code. Subsequently introduce tripartite Ramp Management agreements that allow the ESO to reduce ramp rates at potential points of system stress.

Methodology

Define system trigger

- Define a System trigger level (ramp rate/flow change size) through analysis of current data and operational expertise. A trigger level of a 3500MW flow change was used in the analysis
- The System trigger defined by the maximum ramp rate/flow change size across all I/Cs the ESO control room can manage without extremely high consumer cost or operational challenges

Calculate average ramp rate across all I/Cs

- Using existing modelling data to determine the average ramp rate/flow change size of all I/Cs combined using contractual ramping arrangements and observed behaviour
- Note: the average is **not** the maximum ramp rate. This is determined by the sum of individual average ramp rates over +/- 5 mins of each hour

Determine # flow changes over system trigger

- Using our existing modelling data, apply the defined system trigger to identify all hour periods where the grouped I/C average flow change is greater than the system trigger, on the basis that the ESO would seek to enact the lower ramp rate then

Input results into CBA

- Once periods are identified we compare the flow change size and duration of these interconnectors when a lower ramp rate is imposed
- We then calculate the costs to all parties of imposing this lower ramp rate using both IC provided Imbalance data and Balancing Costs

Modelling Methodology used: Static Ramp Rate (2B)

Ramp Rate of 50MW/min

Option Definition

Change interconnector base rate ramp limit to match generators (50MW/min).

Methodology

Step	Description
Define ramp rate	▶ Define the ramp rate to to used by the interconnectors that are connected to the continental system (e,g, IFA, IFA2) as 50MW/min ▶ All other interconnectors use their default rates (e.g., EWIC, Moyle, NSL)
Run new PLEXOS model	▶ Change parameters in PLEXOS to enable static ramping through addition of ramping constraints ▶ Set time granualirty to 15 minutes to ensure that constraints will be imposed when required
Calculate Balancing Costs based on collective ramp rate	▶ Using modelling data, we determine the average ramp rate of all I/Cs combined based on PLEXOS outputs factoring in contractual ramping arrangements and observed behaviour. Note: the average is **not** the maximum ramp rate. This is determined by the sum of individual average ramp rates over +/- 5 mins of each hour ▶ We calculate the volume of Balancing actions needed for Ramp Management actions
Input results into CBA	▶ We input results into our CBA which compares this option to our counterfactual

Modelling Methodology used: Static Ramp Rate (2C)

Ramp rate of 100MW/min (status quo)

Option Definition

Codify existing ramp rates (100MW/min) within interconnector agreements into the Grid Code.

Methodology

Define ramp rate

- Define the ramp rate to to used by the interconnectors that are connected to the continental system (e,g, IFA, IFA2) as 100MW/min
- All other interconnectors use their default rates (e.g., EWIC, Moyle, NSL)

Run new PLEXOS model

- Change parameters in PLEXOS to enable ramping through addition of ramping constraints
- Set time granualirty to 15 minutes to ensure that constraints will be imposed when required

Calculate Balancing Costs based on collective ramp rate

- Using modelling data, we determine the average ramp rate of all I/Cs combined based on PLEXOS outputs factoring in contractual ramping arrangements and observed behaviour. Note: the average is **not** the maximum ramp rate. This is determined by the sum of individual average ramp rates over +/- 5 mins of each hour
- We calculate the volume of Balancing actions needed for Ramp Management actions

Input results into CBA

- We input results into our CBA which uses this data as the counterfactual

Modelling Methodology used: Dynamic Ramp Rate (3.1)

Ramp Management

Option Definition

ESO dynamically manage ramp rate to meet system needs. A base ramp rate is applied to I/Cs at all times (50MW/min) with increased ramp rates (100MW/min) made available when system conditions allow for this. In principle all I/Cs should follow base ramp rate when moving opposite to demand.

Methodology

Define dynamic time intervals

- ▶ Define dynamic intervals based on historical demand movements (e,g, SP 13 -15 morning pickup)
- ▶ This will also be based on periods when the IC ramp when they ramp in same direction as demand
- ▶ See Appendix C for details of periods of different ramps and rates

Run new PLEXOS model

- ▶ Change parameters in PLEXOS to enable dynamic ramping through addition of time-based constraints

Calculate Balancing Costs based on collective ramp rate

- ▶ Using modelling data, we determine the average ramp rate of all I/Cs combined based on PLEXOS outputs factoring in contractual ramping arrangements and observed behaviour. Note: the average is **not** the maximum ramp rate. This is determined by the sum of individual average ramp rates over +/- 5 mins of each hour
- ▶ We calculate the volume of Balancing actions needed for Ramp Management actions

Input results into CBA

- ▶ We input results into our CBA which compares this option to our counterfactual

Baringa

Option 3.1 - Dynamic Ramp Rate

The dynamic periods are based on 24 * 1-hour periods

0	1	2	3	4	5	6	7	8	9	10	11
50MW	50MW	50MW	50MW	50MW	50MW	More ramping allowed (import only)	More ramping allowed (import only)	More ramping allowed (import only)	More ramping allowed (import only)	50MW	50MW

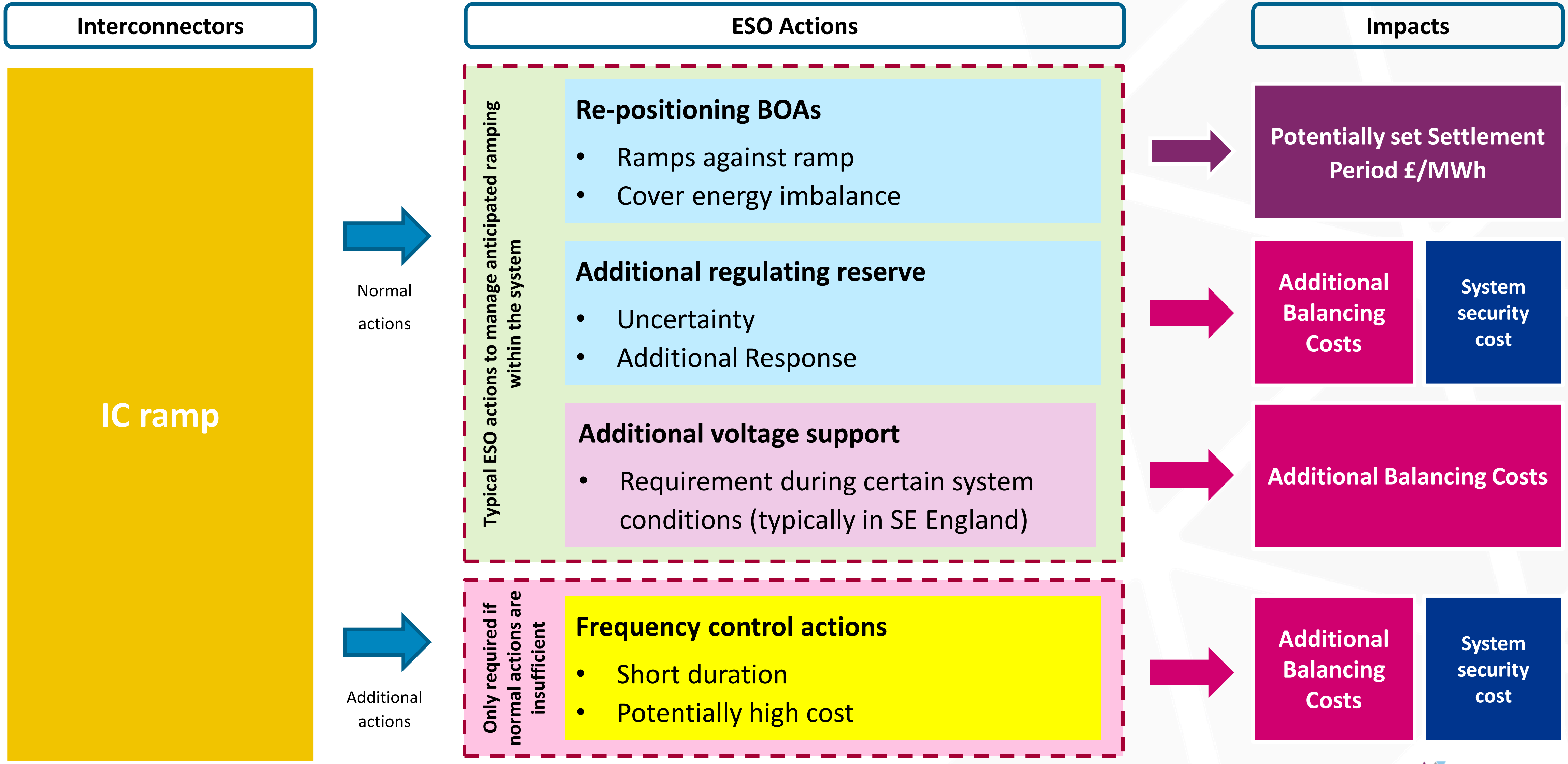
12	13	14	15	16	17	18	19	20	21	22	23
50MW	50MW	50MW	50MW	More ramping allowed (import only)	More ramping allowed (import only)	More ramping allowed (import only)	More ramping allowed (export only)	More ramping allowed (export only)	More ramping allowed (export only)	More ramping allowed (export only)	50MW

Appendix B

Detailed Balancing Actions Cost Methodology

ESO Ramp Management Actions

Mapping various ESO Balancing actions to manage interconnector ramping and their associated impacts



Balancing Costs Methodology

We used various public datasets to assess the relationship between I/C Ramping and Balancing actions

Calculate the volume of Balancing actions required for Ramp Management in 2022 using public data and operational insights

↓

Assess whether a relationship exists between volume required and I/C average ramp rate

↓ **A statistically significant correlation was found**

Apply this relationship to our DA I/C modelled flows 2023-2030

↓

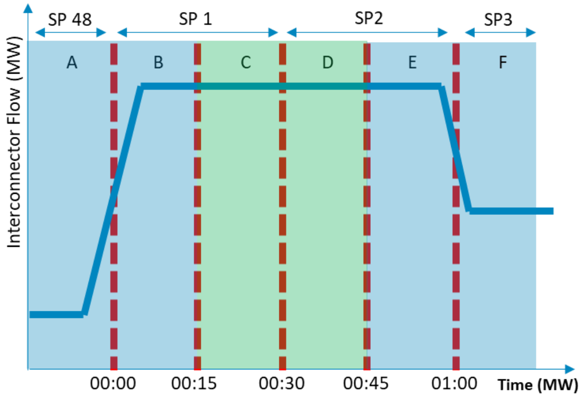
Input estimated Balancing Costs into CBA

- To assess affect of ramping on Balancing actions we explored the existing relationship between high ramp rates and volume of Balancing actions required to manage the ramp
- Using public data, we developed an approach to calculate the volume of Repositioning, Response, Frequency Control and other short term energy actions needed for a given average cumulative ramp rate
- We found a statistically significant relationship exists based on reviewing actions +/- 15 mins to each hour compared to actions taken outside that time
- We further developed a methodology to calculate long-term reserve (where actions needed to be taken between 15-45 mins before an I/C flow change) using operational experience
- Our methodology is described in further detail in Appendix B
- *Note: We have used datasets which can be publicly sourced in our analysis (e.g., ESO Data Portal, ElecLink, RNP)*

Two analytical concepts used

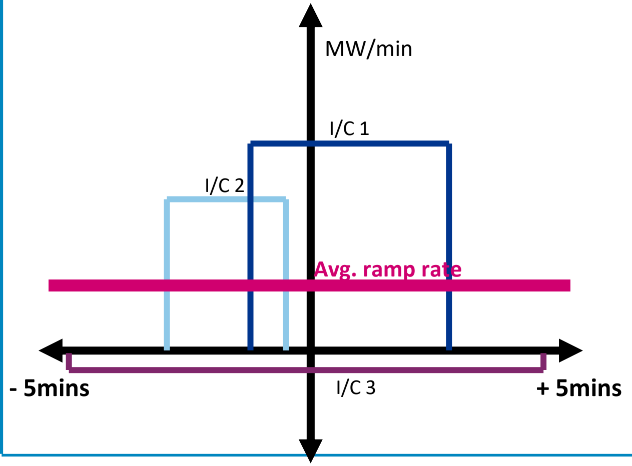
Highlighting two key methodological concepts used to calculate Ramp Management Balancing Costs

Sub-settlement periods



- To determine affect of I/C flow changes on Response, Frequency Control and other short-term actions we divided each hour into four sub-settlement periods
- 15-minute granularity has been chosen to capture difference between GREEN periods where we expect little cost affect of I/C flow changes and BLUE periods where we expect costs to be affected by flow changes

Average Total Ramp Rate



- Interconnectors over 2022 ramp at different times
  - e.g. IFA2 and ElecLink ramped evenly over +/- 10 mins compared to NEMO and BritNed that ramped at 100 MW/min for a certain duration. All can spill if ramping over 1000MW across 10 mins
- We need to determine the total average ramp rate to assess how costs across sub-settlement periods differed based on ramp rate
- Using contractual principles and operational experience we calculated an average ramp rate that would be experienced over 10 mins (+/- 5 mins to each hour)
- This method incorporates flow change size and duration – as such we believe it is the best estimate we can use however it may dampen the affect I/Cs could have on Balancing Costs

Our Methodology

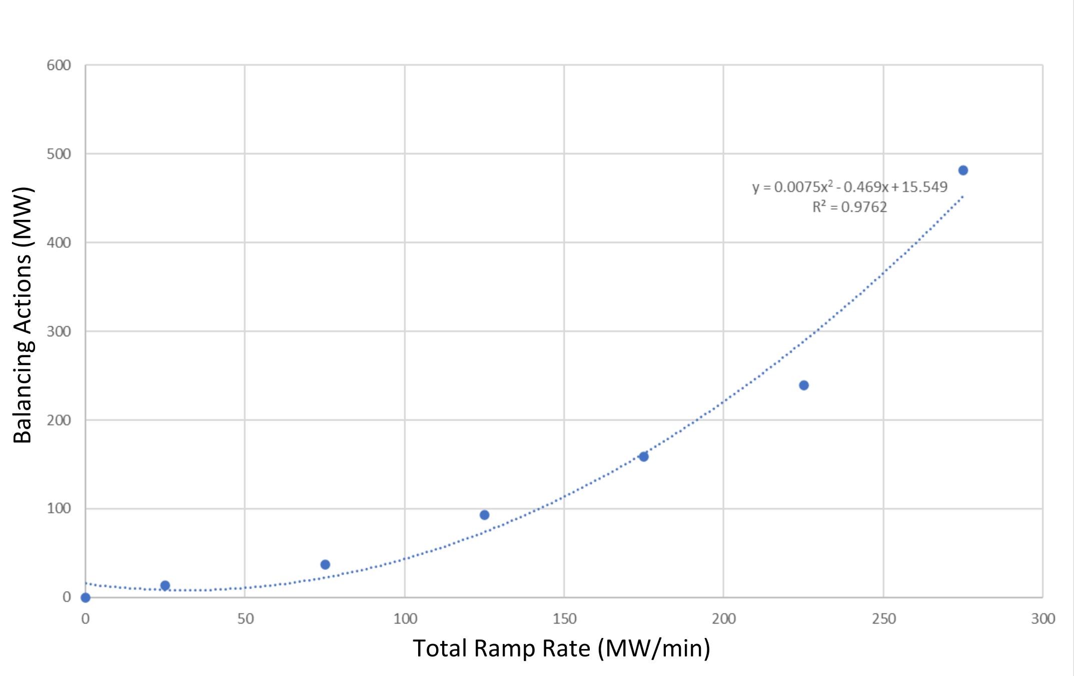
This approach applied to public data

Inputs	Analysis				Outputs
BOA Data (Categorised based on instruction time across 96 sub-SPs)	Repositioning	Filter BOAs for repositioning bids (excluding “Response”, “System”, “Constrained Loss”)	Calculate repositioning cost for each action	Determine average cost for each sub-settlement period	Average volume of Balancing actions per sub-settlement period in 2022 based on flow change intervals of 400MW
	Response	Filter BOAs for “Response” bids. Exclude any actions <5 mins	Calculate response cost for each action	Determine average cost for each sub-settlement period	+
	Freq Control	Filter BOAs for <5 mins duration	Calculate cost for each action	Determine average cost for each sub-settlement period	Average volume of Balancing actions per average ramp rate experienced in 2022
ASDP Data (Categorised based on instruction time across 96 sub-SPs)	Freq Control	Filter ASDP for “Fast Response” and “STOR”	Calculate cost for each action	Determine average cost for each sub-settlement period	
Operational expertise	Reserve	Establish with operation teams how much reserve would be required for a given flow change size and ramp rate. Note the duration of time reserve is required varies on flow change size	Designed equation to calculate this Reserve required.		Average cost of reserve per given I/C flow change

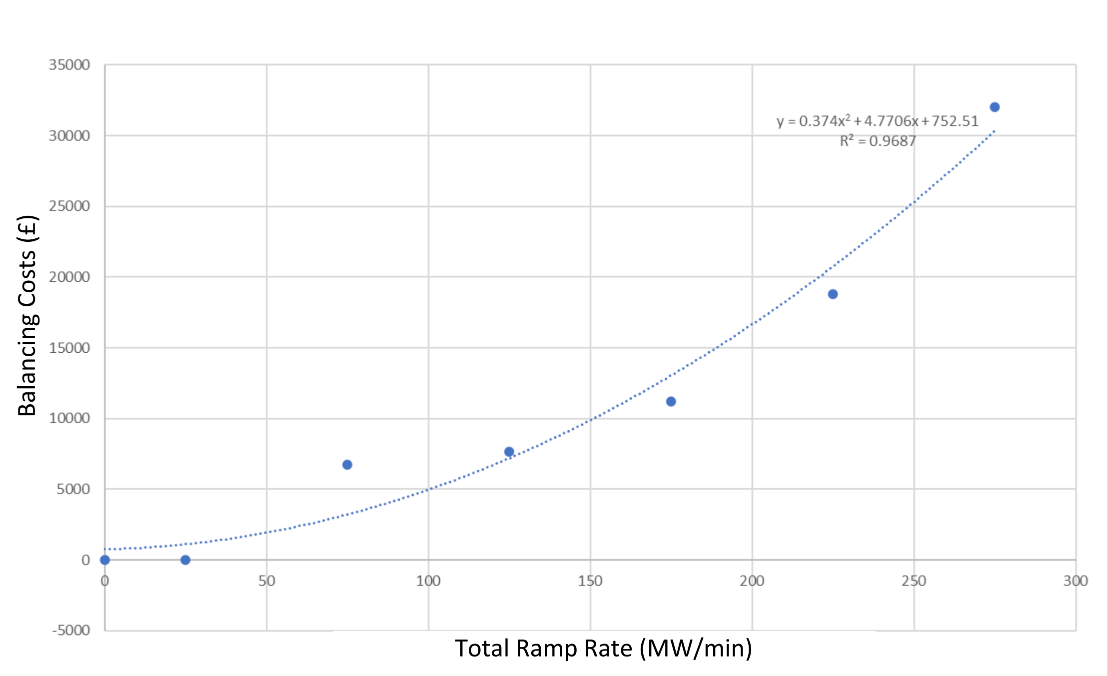
Relationships existed for Repositioning, Response and Frequency Control Actions

Balancing actions procurement costs and volumes were correlated to the average total ramp rate

Volume



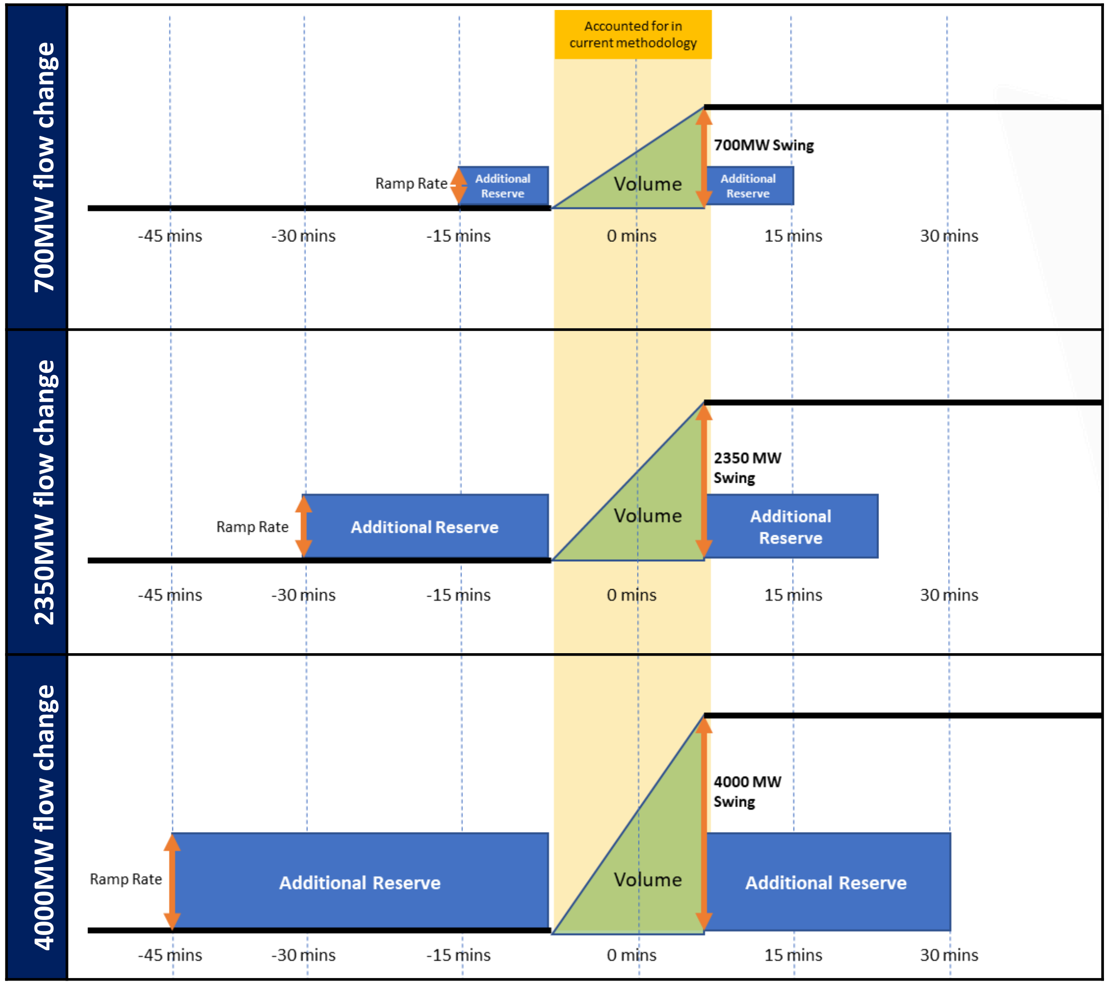
Cost



**Note only 13 flow changes occurred over 300-450MW/min. As such these results have been removed from analysis to ensure data reliability*

Reserve Calculation

Operational expertise and experience informed the approach designed to calculated Reserve requirements



- Due to the complexity of ramp management, it is not always possible to untangle the reserve requirement due to interconnectors from other activities
- Therefore, we have reviewed the theoretical basis for requiring reserve to cover uncertainties (inc. energy imbalance)
- For any 700MW flow change across continental I/Cs, this additional reserve would be procured within +/- 15 mins of a flow change and last less than 30 mins. As such it would be captured by our existing methodology
- However, for overall flow change sizes between 700MW – 4000MW additional reserve would be required
- All flow changes above 4000MW would follow the same calculation as 4000 MW
- This would match the total I/C ramp rate, as this would be the anticipated reserve volume requirement

Calculating 2023 – 2030 Balancing Costs

Applying Ramp Management Balancing Costs to modelled flows

1

Calculate the Total Ramp Rate and flow change size for each hour (2023-2030)

- Using PLEXOS modelled I/C hourly positions we determine the total flow change size of continental I/Cs and the total ramp rate (using same methodology outlined in "Our Methodology" slide)

2

Determine volume of Balancing actions required

- **Response, Frequency Control and Repositioning Reserve**: we use a cost lookup table based on total ramp rate intervals of 50MW
- **Reserve**: apply our formula to determine the length of time Balancing actions need to be procured

3

Apply Wholesale GB Price to calculated volume

- We apply modelled PLEXOS wholesale GB prices to Balancing actions volumes
- These are the best estimated prices that are likely to be experienced
- We acknowledge this may not fully reflect the premium paid to procure energy closer to real-time (based on experience this could be up to 10%)

Appendix C

PLEXOS Modelling Assumptions

Baringa PLEXOS reference case and ESO Future Energy Scenarios (FES)

The relationship between the two approaches

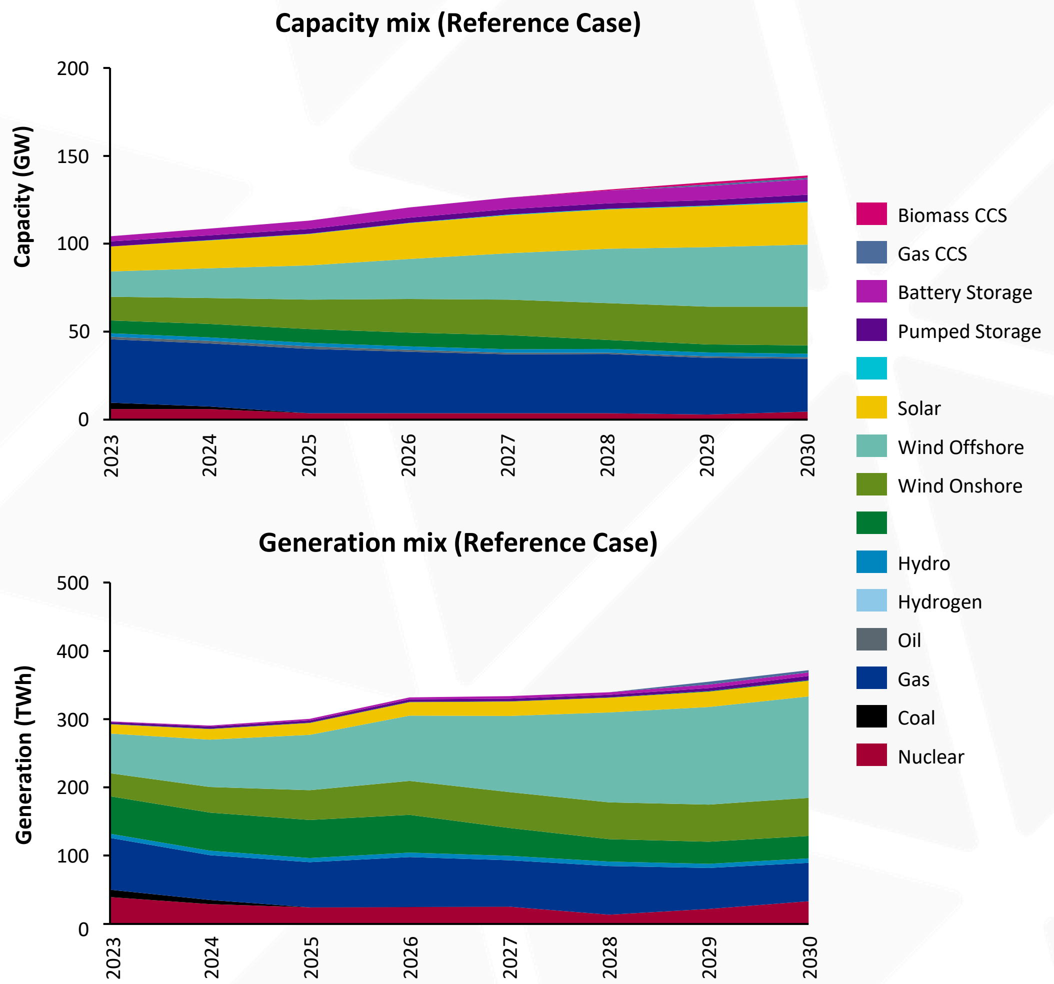
As part of our independent analysis of the study horizon (2023 to 2030) Baringa used the Baringa Reference Case as the core scenario for the analysis. We note that this is different to the ESO FES which is based on four different credible energy pathways. Whilst the Reference Case uses FES capacity build out assumption and demand projection, the scenario constructs are different.

- Baringa apply unit level insight to account for asset specific economics (assumptions on plant closure and investment decisions for example, base on market revenues and missing money) to develop a set of assumptions that account for top-down system needs as well as near-term commercial investment drivers
- The FES is required (by license condition) to take account of range of stakeholder views on capacity, i.e., if that's what stakeholders want to connect, then what does the network need to do to be ready. Our scenarios are economic in focus, i.e., focusing on capacity build out for given commodity prices and policy incentives
- Our independent best view on capacity build out assumptions typically sits within the envelope of the FES assumptions, noting that the FES scenarios are deliberately designed to test a set of future energy outcomes
- Baringa has a dedicated team who review and update the assumption on a regular basis, they also incorporate the latest FES data into their analysis as and when the ESO release their latest version of the FES

Capacity and generation mix – Reference Case

Our modelling scenario is underpinned by our assumptions on new generation capacity build and retirement

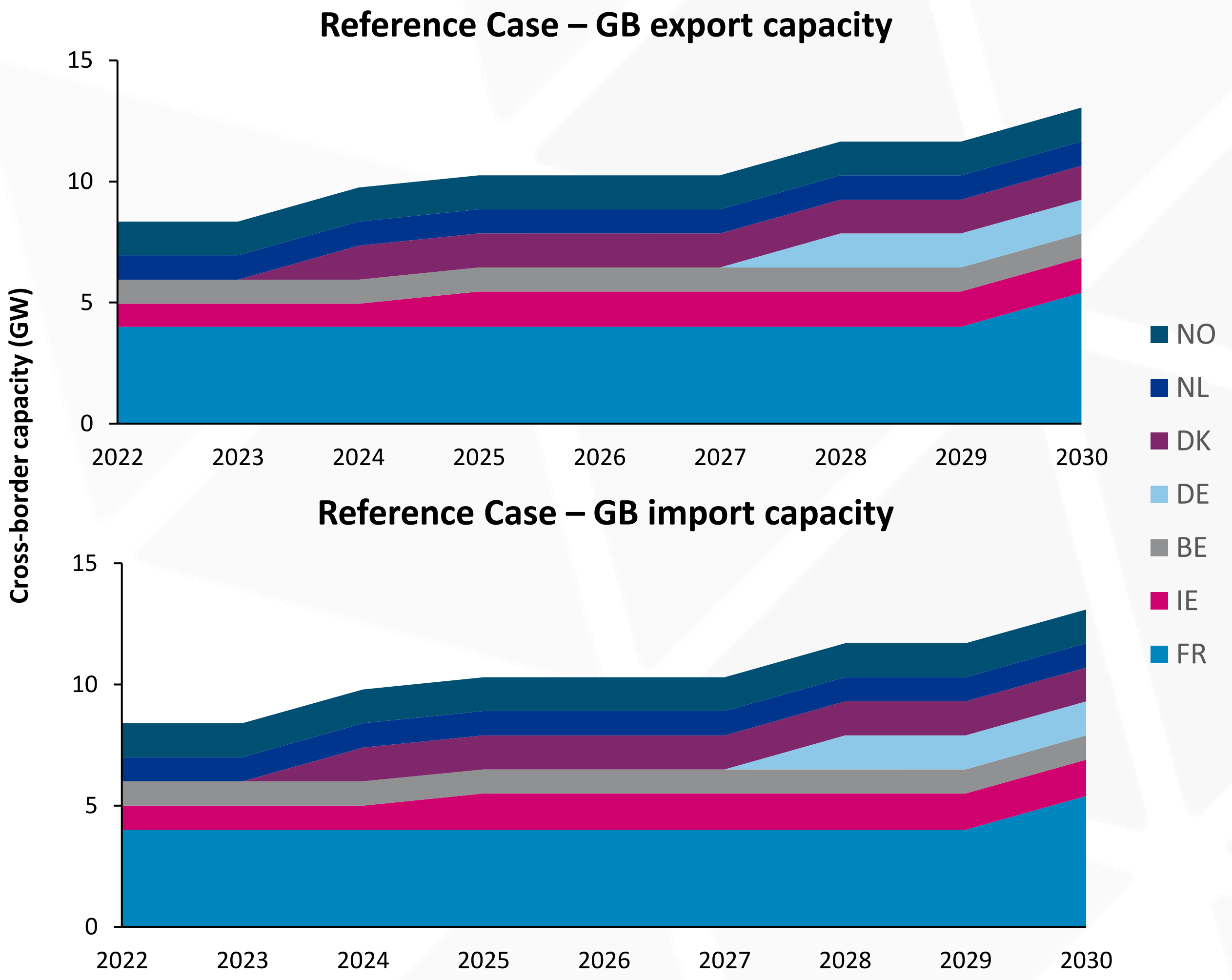
- The charts opposite show annual capacity and generation mix in GB in the Reference Case
- Investment and closure decisions drive changes in the capacity mix and in our modelling are based on a combination of national policy ambition or decisions, and the economics of individual units and generators in the market (i.e., a generator will close where it can no longer cover its costs from market revenues)
- In GB, wind and solar capacity increases significantly due to CfD support for offshore wind in the near term. We project wind capacity (onshore and offshore) to more than double from 27 GW in 2023 to 57 GW in 2030. Solar capacity also increases significantly, from 14 GW in 2023 to 24 GW in 2030
- Coal-fired generation is phased out by the end of 2024 despite some short-term delay to closures. There are also significant closures of existing gas capacity leading to a downward trend in the contribution of gas to both the capacity mix and generation. This, combined with increasing peak demand, is projected to lead to lower capacity margins
- A range of technologies are built in the Reference Case, including gas CCS, gas engines and batteries, to meet the target capacity margin of approximately 3% to 5% in the medium to long term. Some existing biomass capacity is converted with the addition of CCS in the late 2020s and nuclear capacity also increases from the late 2020s
- By 2030, 75% of generation comes from wind, solar, biomass, biowaste and hydro



Interconnector capacity – Reference Case

GB interconnection capacity is assumed to increase from 8.4 GW in 2023 to 13.1 GW by 2030

- In the short-term, new capacity build in the Baringa model is based on information on project status and progress, and profitability of each project over the assumed lifetime (in the long-term we rely on economic assessment alone). Our view is developed based on iteration of capacity build on each border. Where price differentials, and the resulting revenue for a new interconnector are sufficiently large to incentivise investment, we take this as a market signal for new investment
- Great Britain currently has an import and export capacity of 8.4 GW
- The capacity of interconnection is expected to increase in the future as existing projects in the pipeline come online supported by positive economics due to the hourly price differentials between markets
- Export and import capacity is assumed to increase to 13.1 GW by 2030 in the Reference Case. This is due to additional interconnection capacity with France and adding new interconnection capacity with Denmark and Germany. The NeuConnect interconnector with Germany is now projected to become operational by 2028
- We note that there are a number of additional projects that may come forward in Ofgem's Cap and Floor window 3 which have not been modelled explicitly in this study. Our approach to date has been to consider medium-term projects based on project economics rather than picking winners from the range of projects currently in the pipeline



Baringa DA PLEXOS Pan European reference case

Our yearly base assumptions

Baringa Reference Case
2022 Q4
Great Britain
Data is in real 1st Jan 2022 money unless stated otherwise

Prices - Fuels and Carbon		2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Brent	*$/bbl*	78.4	70.3	65.7	62.4	65.2	71.3	77.5	81.3
Coal CIF ARA	*$/tonne*	182.1	165.5	150.2	139.9	127.4	106.6	85.9	72.9
Gas NBP	*p/therm*	262.1	212.5	148.4	84.4	80.4	73.1	65.8	61.9
Carbon UKA+CPS	*£/tonne*	74.1	83.2	86.1	82.6	78.3	75.8	74.9	73.2
Carbon UKA**	*£/tonne*	58.1	67.8	71.2	69.1	67.7	68.1	70.1	71.4
Carbon CPS	*£/tonne*	16.0	15.3	14.9	13.6	10.6	7.7	4.8	1.8

Demand		2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand	*MW*	59,266	60,265	61,148	62,037	63,051	64,143	65,018	65,882
Annual Demand	*GWh*	310,755	316,314	322,039	327,568	333,075	338,710	347,550	356,707

Installed Capacity by type		2023	2024	2025	2026	2027	2028	2029	2030
Nuclear	*MW*	5,873	5,873	3,538	3,538	3,538	3,538	2,798	4,398
Coal	*MW*	3,764	1,500	0	0	0	0	0	0
Gas	*MW*	35,927	35,803	36,628	34,915	33,532	33,632	32,327	30,087
Gas CCS	*MW*	0	0	0	0	0	0	900	900
Oil	*MW*	1,472	1,506	1,480	1,104	878	878	878	878
Hydrogen	*MW*	0	0	0	0	0	0	0	0
Hydro	*MW*	2,017	2,027	2,037	2,047	2,057	2,067	2,077	2,087
Biomass and Waste	*MW*	7,263	7,689	7,789	7,889	7,989	5,200	4,655	4,755
Biomass CCS	*MW*	0	0	0	0	0	600	1,200	1,200
Wind Onshore	*MW*	13,519	14,794	16,730	19,042	20,242	20,917	21,442	21,967
Wind Offshore	*MW*	14,302	16,781	19,477	22,737	26,405	30,895	33,851	35,251
Solar	*MW*	14,242	15,842	17,792	20,392	21,592	22,367	23,266	24,165
Other Renewables	*MW*	125	170	215	260	305	350	395	440
Pumped Storage	*MW*	2,828	2,828	2,828	2,828	3,128	3,128	3,128	3,828
Battery Storage	*MW*	2,839	3,719	4,597	5,829	6,584	7,334	8,004	8,804

Interconnection Capacity		2023	2024	2025	2026	2027	2028	2029	2030
Import Capacity, Total	*MW*	8,400	9,800	10,300	10,300	10,300	11,700	11,700	13,100
Export Capacity, Total	*MW*	8,350	9,750	10,250	10,250	10,250	11,650	11,650	13,050

New interconnectors between 2023 – 2030 (study horizon)

Our model makes the following assumptions on new interconnectors. Please note this is based on our experience and does not reflect that we believe others will not be build and connected

Interconnector	Capacity (MW)	Connection Date in Model
Denmark	1400	2024
Ireland	500	2025
Germany	1400	2028
France	1400	2030

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