OFFSHORE COORDINATION

Sensitivity study on the effect of change in the starting date of offshore grid coordination

National Grid ESO

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Customer:	National Grid ESO	Tel: +31 26 356 2370
Customer contact:	Luke Wainwright	National HVDC Centre 11 Auchindoun Way, Wardpark, Cumbernauld, G68 0FQ
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Project No.:	10245682	EPNC
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Objective: Sensitivity study on the effect of shifting the starting date of integration in offshore grid design.

Prepared by:	Reviewed by:	Verified by:
Oluwole Daniel Adeuyi	Bridget Morgan	Maksym Semenyuk
Benjamin Marshall		
Víctor García Suárez		

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1 INTRODUCTION

1.1 Purpose of this Sensitivity Study

This sensitivity study is supplementary to the assessment that was reported in the ESO's Offshore Coordination project's Holistic Planning Report[1] and Cost Benefit Analysis ('CBA') Report[2]. One key assumption for that assessment was that the implementation of integrated offshore network designs would start from 2025.

The purpose of this additional sensitivity analysis was to assess potential impacts of a change to the assumption made in respect of the implementation date of integrated offshore network designs. This sensitivity study considered the potential impacts on conceptual offshore network designs, transmission system onshore boundary flows and CBA, if implementation of integrated offshore network designs began in 2030.

As part of this report, a case study using an alternative 2030 start date for implementation of integrated offshore transmission networks is compared against the base case of a 2025 start date considered in the Holistic Planning Report.

Figure 1-1 is an illustration of the regional offshore wind growth across 6 different regions in GB using the 2020 Future Energy Scenarios ('FES')[3] Leading the Way ('LW') Scenario data and provides a high level insight of the effect of changes to the start date assumption. By 2030, not just the infrastructure for the connected projects by that date are present, but also the infrastructure for large areas of wind farms to be connected in full by 2032 are also present and relevant to our consideration.

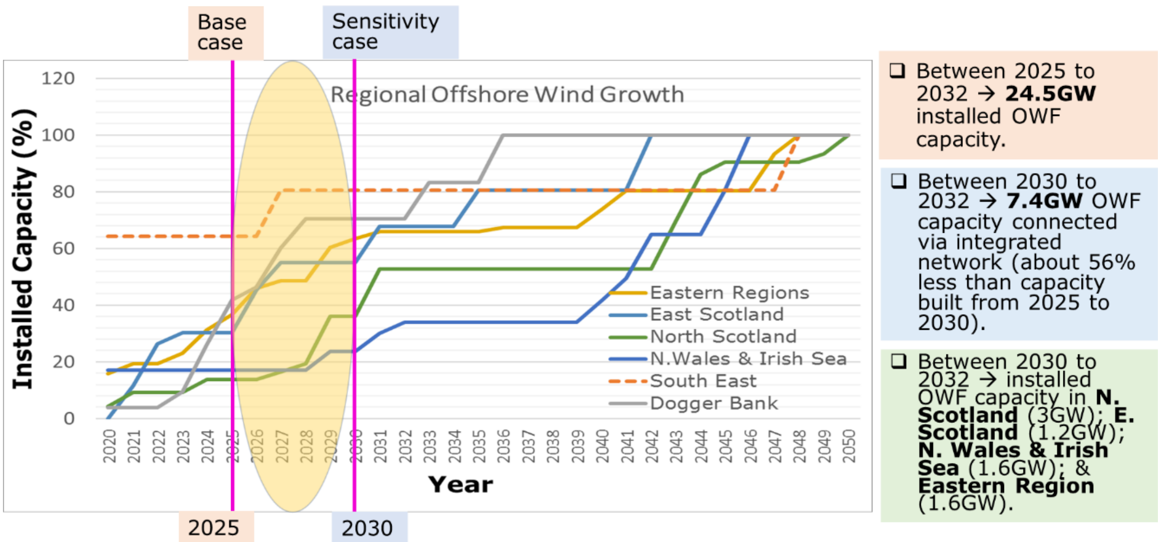

Figure 1-1 Regional offshore wind growth in GB for 2025 and 2030 start dates for integrated offshore networks

The total installed offshore wind capacity in the LW Scenario between 2025 and 2032 is 24.5 GW, of which 17.1 GW is expected to be installed from 1st January 2025 until end of December 2029, and an extra 7.4 GW is expected to be installed from 1st January 2030 until end of 2032. Based on this data, the offshore

[1] Holistic Approach to Offshore Transmission Planning in Great Britain (DNV GL, National HVDC Centre, EPNC). https://www.nationalgrideso.com/document/177221/download

[2] Cost-Benefit Analysis of Offshore Transmission Network Designs (DNV GL, National HVDC Centre, EPNC; 2020). https://www.nationalgrideso.com/future-energy/projects/offshore-coordination-project/documents

[3] ESO Future Energy Scenarios 2020. https://www.nationalgrideso.com/document/173821/download

wind capacity installed from 2030 to 2032 is expected to be about 56% less than the installed offshore wind capacity build expected from 2025 up to the end of 2029.

1.2 Regional Zones

For ease of comparison, the results of the sensitivity analysis (e.g. asset count, boundary power transfers, cost, etc.) are provided on a regional zone basis, which is similar to that used for the Offshore Coordination Project's Holistic Planning Report and CBA Report. The regional zones are North Scotland, East Scotland, Dogger Bank, Eastern Regions, South East and North Wales and Irish Sea. This is illustrated in Figure 1-2 below:

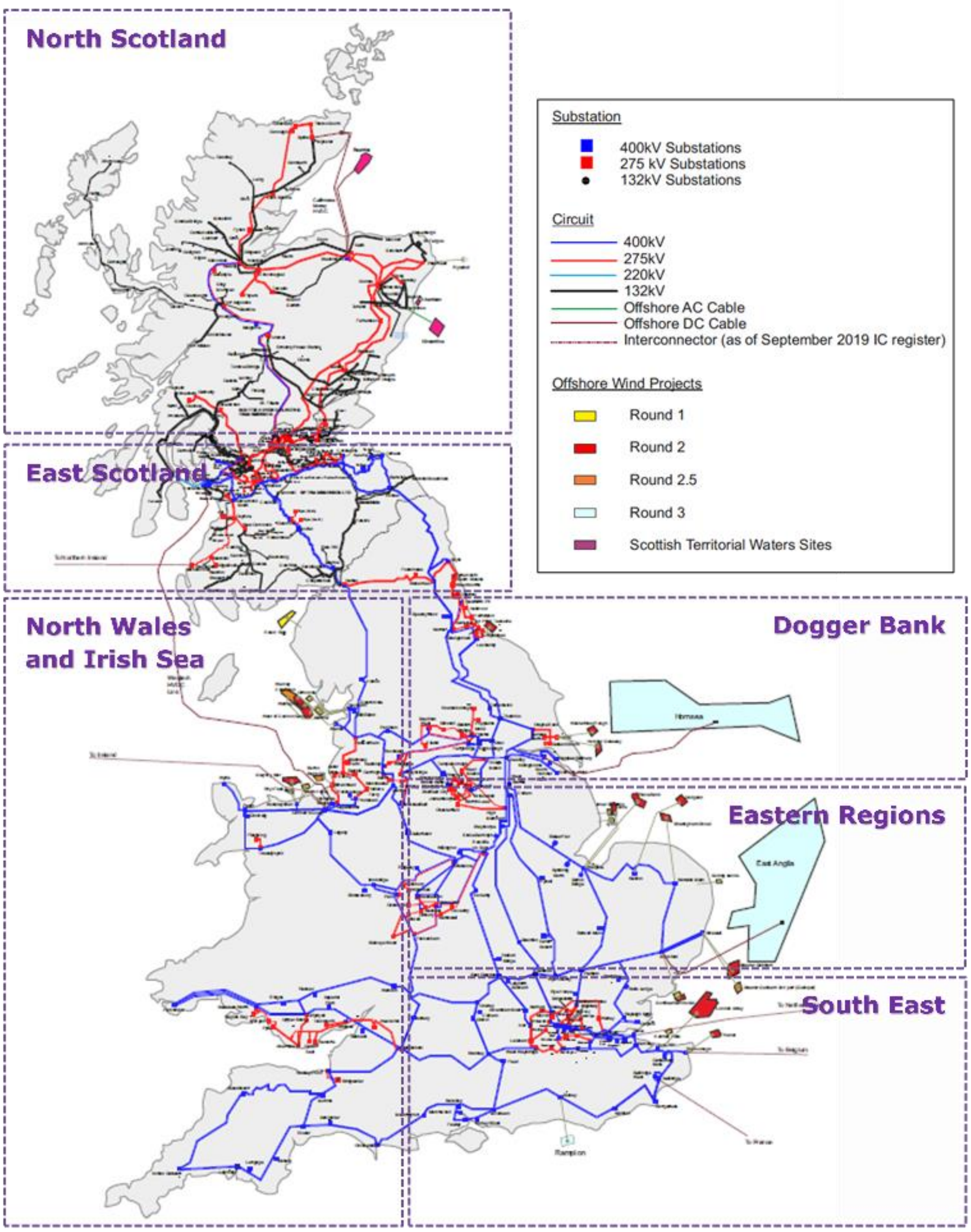

Figure 1-2 GB's existing transmission system and considered regional zones.

The following sections of this report summarise the key findings of the sensitivity study carried out and describes the:

- modified integrated offshore network design approach that was developed;
- additional power system analysis carried out, and
- results from the associated CBA.

2 MODIFIED INTEGRATED NETWORK DESIGN APPROACH

A modified network design is developed for the sensitivity study, comprising a combination of the current (project-specific) approach with the integrated transmission approach. The approach is summarised as:

- Status quo project-by-project decisions built up as before to 2030.
- Integration begins ahead of 2030 addressing decisions needed to support connections between 2030-2032 which overlap in construction with status quo. For these, the study:
  - Examines the extent of original integrated solutions that may be adapted or modified to accommodate the additional onshore GB power flow and boundary requirement.
  - If this is not possible, offshore network designs and onshore landing points are adapted where relevant to minimise further onshore network effect. This may in turn drive different offshore network ratings to transfer more power further south into the onshore network.
  - Where areas of transition network may be incomplete or not present to support the generation in the way it was before in an integrated approach, alternative connection options are identified which complement the above two objectives.

The current approach is used for connection of 17.1 GW of installed offshore wind capacity between 2025 and 2030, with the remaining 7.4 GW of installed offshore wind capacity between 2030 and 2032 connected using an integrated transmission approach. The sensitivity study considers that:

- Transmission solutions based on the current approach with the associated onshore reinforcements are implemented on a year-on-year basis between 2025 to 2029;
- Integrated transmission network is available to support connection of installed offshore wind farm capacities from 1st January 2030 up to 2050;
- Transmission network capacity is available at least 2 years ahead of offshore wind generator commissioning; and
- Options for de-rating transmission capacity within the integrated designs presented in Holistic Planning report is explored first, prior to any major modifications to the conceptual design topology, if required.

In the base case, a 2030 integrated network approach is used for connecting the total installed offshore wind capacity of 24.5 GW between 2025 and 2032. Also, the integrated transmission network approach is used for connection of offshore capacity beyond 2032 up to 2050.

The key inputs to the sensitivity study and the base case are:

- Installed offshore wind farm capacity from 2025 to 2050 background on the Leading the Way Scenario of the 2020 Future Energy Scenario;
- Onshore network reinforcements with proceed signal in the 2020 Network Option Assessment[4] report is implemented in system studies, but not illustrated in the simplified conceptual network diagrams; and
- Offshore transmission connections and extra onshore reinforcements required in addition to those outlined in the 2020 NOA report are illustrated on the 2030 and 2050 network designs (seen in section 3).

[4] ESO Networks Options Assessment 2020: https://www.nationalgrideso.com/document/162356/download

2.1 Modified Network Design for 2030

Figure 2-1 is an illustration of the 2030 integrated network designs. The counterfactual case is show in Figure 2-1 a, Integrated approach supporting offshore wind connections with a start date of 2025 is shown in Figure 2-1 b and the sensitivity study case of Integrated schemes to support offshore wind connections with 2030 start date is presented in Figure 2-1 c.

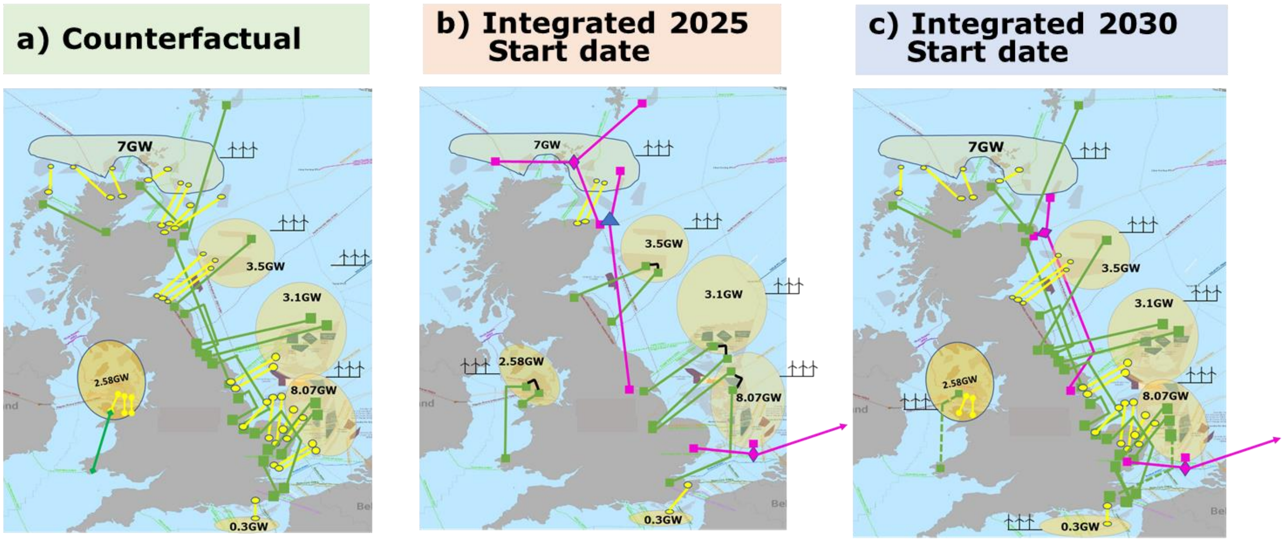

Figure 2-1 2030 Integrated Network Designs (a) Counterfactual. (b) Integrated with start in 2025 (c) Integrated with the start in 2030

Figure 2-2 shows the asset count of 2030 modified integrated network for offshore wind farms connections for the counterfactual case, Integrated with 2025 start date case and Integrated with 2030 start date case.

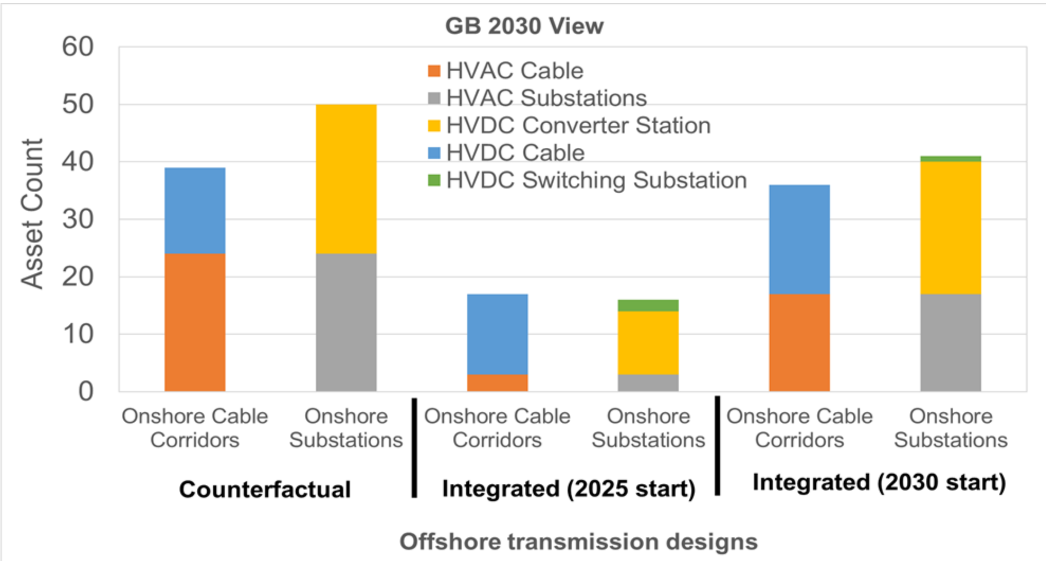

Figure 2-2 2030 network asset count comparison for counterfactual, base case (2025 start) and sensitivity case (2030 start)

The implementation of integrated transmission solutions to support offshore wind connections with a start date of 2030 could result in extra onshore landfall locations in the range of 40-60% by 2030 compared to the case of Integrated with a start date of 2025, as seen in Figure 2-2.

2.2 Modified Network Design for 2050

Figure 2-3 is an illustration of the 2050 integrated network approaches. The counterfactual case is shown in Figure 2-3 a, the Integrated with 2025 start date case is shown in Figure 2-3 b and the sensitivity study case of Integrated with 2030 start date is presented in Figure 2-3 c.

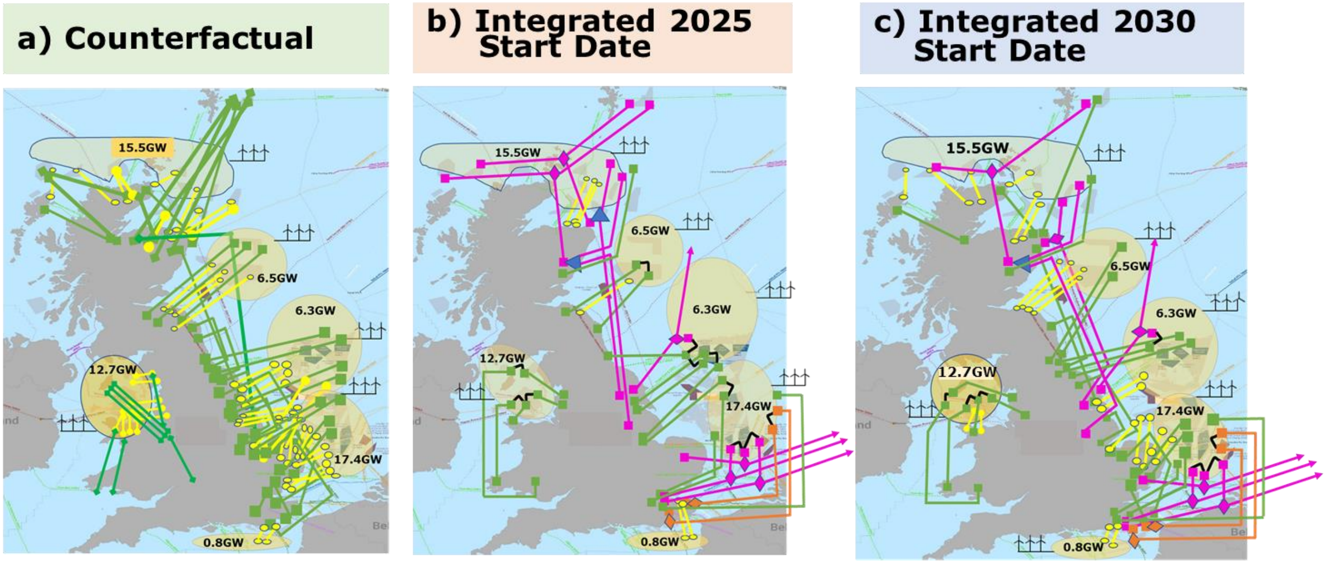

Figure 2-3 2050 Integrated Network Designs. (a) Counterfactual. (b) Integrated with start in 2025. (c) Integrated with the start in 2030.

Figure 2-4 shows the asset count of 2050 modified integrated network for offshore wind farms connections for the counterfactual case, Integrated with start date of 2025 case and Integrated with start date of 2030 .

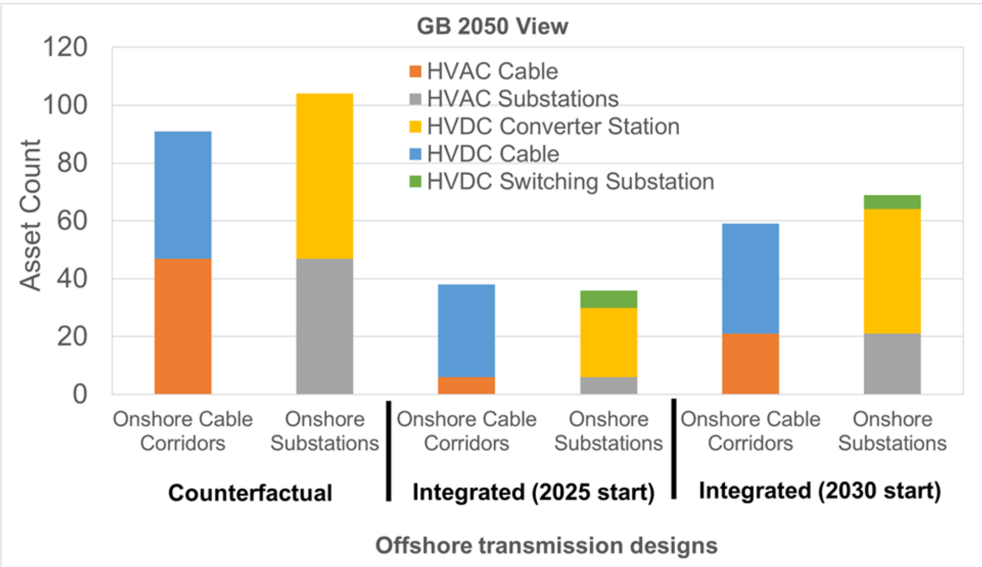

Figure 2-4 2050 network asset count comparison for counterfactual, base case (2025 start) and sensitivity case (2030 start)

The implementation of integrated transmission solutions to support offshore wind connections with a start date of 2030 could result in extra onshore landfall locations in the range of 25-30% by 2050 compared to the case of Integrated with a 2025 start date, as seen in Figure 2-4.

2.3 Regional Asset Count

The effect of later transition to Integrated connection approaches from a start date of 2025 to a start date of 2030 varies across the six regional offshore wind areas due to different pace of change and scale of growth. An asset count of onshore substations and onshore cable corridors is analysed and compared per region for three different cases: (i) Counterfactual (C); (ii) Integrated 2025 start (I) and (iii) Integrated 2030 start (I30). A positive value of percentage (%) difference reflects a decrease in the number of onshore assets required for integrated approaches compared to the counterfactual. A negative value of % represents an increase in the number of assets required by the integrated network compared to the counterfactual (i.e. percentage = (**C**-**I** ÷ **C**) * 100%)).

2.3.1 2030 Onshore Landfall Locations

Table 1 is a summary of the 2030 asset count of onshore substations per region for Counterfactual case (C), Integrated 2025 start case (I), and Integrated 2030 start case (I30). *Note this includes the effect of offshore wind connections in North Scotland and East Scotland, which land in Dogger Bank via the Integrated offshore network designs.

Table 1: 2030 Onshore Substations Asset Count per region

	Counterfactual **(C)**	Integrated 2025 start **(I)**	Difference **(C-I)**%	Integrated 2030 start **(I30)**	Difference **(C-I30)**%
North Scotland	14	5	64%	12	14%
East Scotland	5	2	60%	4	20%
Dogger Bank	8	2	75%	10	*-25%
Eastern Regions	13	3	77%	12	8%
South East	3	2	33%	4	*-33%
North Wales	5	2	60%	3	40%
Total	**48**	**16**	**67%**	**45**	**6%**

Table 2 is a summary of the 2030 asset count of onshore substations per region for Counterfactual case (C), Integrated 2025 start case (I), and Integrated 2030 start case (I30). *Note this includes the effect of offshore wind connections in North Scotland and East Scotland, which land in Dogger Bank via the Integrated offshore network designs.

Table 2: 2030 Onshore Cable Corridors Asset Count per Region

	Counterfactual **(C)**	Integrated 2025 start **(I)**	Difference **(C-I)**%	Integrated 2030 start **(I30)**	Difference **(C-I30)**%
North Scotland	14	8	43%	11	21%
East Scotland	5	2	60%	4	20%
Dogger Bank	8	2	75%	10	*-25%
Eastern Regions	13	3	77%	12	8%
South East	3	2	33%	4	*-33%
North Wales	5	2	60%	3	40%
Total	**48**	**19**	**60%**	**44**	**8%**

For the 2030 network designs, a transition to integrated transmission approaches from 2025 (I case) would result in 60-67% asset savings in total number of onshore substations and cable corridors compared to the Counterfactual case. The effect of later transition to integrated approaches from 2030 (I30 case) would result in a 6-8% reduction in the total number of onshore substations and cable corridors by 2030 compared to the Counterfactual case. The total number of onshore assets required in the Integrated 2030 start (I30) case is 52-61% greater than the onshore assets of the Integrated 2025 start (I) case.

The Dogger Bank region would require 25% extra onshore assets (onshore substations and cable corridors) and the South East region would require 33% extra onshore assets for the Integrated 2030 start (I30) case compared to the Counterfactual case due to later transition to coordinated offshore grids.

North Scotland, East Scotland, Eastern Regions and North Wales would require (21%, 20%, 8% and 40%) lesser number of onshore cable corridors and (14%, 20%, 8% and 40%) lesser number of onshore substations in the I30 case compared to the Counterfactual case. However, across all regions the Integrated 2025 start case compared to counterfactual offers greater asset savings per region than the case of Integrated 2030 start compared to the Counterfactual, as outlined in Table 1 and Table 2.

2.3.2 2050 Onshore Landfall Locations

Table 4 is a summary of the 2050 asset count of onshore substations per region for the Counterfactual case (C), Integrated 2025 start case (I), and Integrated 2030 start case (I30).

Table 3: 2050 Onshore Substations Asset Count per Region

	Counterfactual **(C)**	Integrated 2025 start **(I)**	Difference **(C-I)**%	Integrated 2030 start (I30)	Difference **(C-I30)**%
North Scotland	25	10	60%	18	28%
East Scotland	9	3	67%	5	44%
Dogger Bank	18	5	72%	13	28%
Eastern Regions	27	4	85%	13	52%
South East	7	9	**-29%	11	**-57%
North Wales	20	5	75%	7	65%
Total	**106**	**36**	**66%**	**67**	**37%**

Table 3 is a summary of the 2050 asset count of onshore substations per region for the Counterfactual case (C), Integrated 2025 start case (I), and Integrated 2030 start case (I30). **Note this includes the effect of offshore wind connections in the Eastern Region, which land in the South East via the Integrated offshore network.

Table 4: 2050 Onshore Cable Corridors Asset Count per Region

	Counterfactual (C)	**Integrated 2025 (I25)**	**Difference (C-I25)%**	**Integrated 2030 (I30)**	**Difference (C-I30)%**
North Scotland	25	16	36%	20	20%
East Scotland	9	3	67%	5	44%
Dogger Bank	18	5	72%	13	28%
Eastern Regions	27	4	85%	13	52%
South East	7	9	**-29%	11	**-57%
North Wales	19	5	74%	7	63%
Total	**105**	**42**	**60%**	**69**	**34%**

For the 2050 network designs, a transition to integrated transmission approaches from 2025 (I case) would result in 60-66% asset savings in total number of onshore substations and cable corridors compared to the counterfactual case. **Note this includes the effect of solutions in the Eastern Region, which land in the South East via the Integrated Offshore Network.

A later transition to integrated approaches from 2030 (I30 case) would result in a 34-37% reduction in the total number of onshore substations and cable corridors by 2030 compared to the counterfactual case. The total number of onshore assets required in the Integrated 2030 start (I30) case compared to counterfactual is 26-29% greater than the Integrated 2025 start (I) case compared to counterfactual.

The South East region would require 57% extra onshore substations and cable corridors for the Integrated 2030 start (I30) case compared to Counterfactual case, rising from 29% extra onshore assets required for the Integrated 2025 start (I) case compared to the counterfactual.

North Scotland, East Scotland, Dogger Bank, Eastern Regions and North Wales would require (21%, 44%, 28%, 52% and 63%) lesser number of onshore cable corridors and (28%, 44%, 28%, 52% and 65%) lesser number of onshore substations in the I30 case compared to the Counterfactual case. However, across all regions the Integrated 2025 start case compared to counterfactual offers greater asset savings per region than the case of Integrated 2030 start compared to the counterfactual, as shown in Table 4 and Table 3.

2.4 Summary of modified network designs

The modified conceptual network designs indicate that up to 37% (where 100% is the number of assets required for Counterfactual) less onshore landfall locations for cable corridors and onshore substations would be required by 2050 due to a later transition in the start of integrated offshore transmission approaches in 2030 compared the counterfactual case. An alternative start date of 2025 for Integrated transmission approaches could achieve up to 66% reduction in number onshore landfall locations compared to the counterfactual case.

The additional onshore infrastructure associated with the a 2030 start date for coordination of offshore wind connections is mainly due to the use of project-specific connection approaches (status quo) and the associated onshore reinforcement for connection of offshore wind projects from 2025 until end of 2029.

By 2030 and 2050 the regions that see the largest increase in additional onshore infrastructure are Dogger Bank, Eastern Regions and North Scotland, while the least increase occurs across North Wales and Irish Sea, South East and East Scotland.

3 POWER SYSTEM ANALYSIS

The power system analysis of the holistic conceptual offshore network designs has been expanded with a new scenario that reflects the impact of starting the integration process in 2030, instead of in 2025.

Due to the later start of the integrated approach, the power injections for the year 2030 correspond to the Counterfactual design, these arising from the project by project connections via counterfactual approaches onto the onshore system. Therefore, the resulting power flow conditions for the year 2030 are equivalent to the ones discussed in the Holistic Offshore Transmission Planning report. Consequently, only simulations for the year 2050 has been performed in the sensitivity analysis.

In the Holistic Offshore Transmission Planning report, the challenges arising from the Counterfactual design regarding boundary power transfers and transmission line loading levels were addressed by onshore reinforcements. These reinforcements are again illustrated in the sensitivity analysis for 2030, now being triggered ahead of the transition to the integrated approach and combined with the early integrated infrastructure required to support the future offshore wind connections in the years immediately following.

This section on power system analysis follows a similar structure to the original report. First, the study inputs, modelling assumptions and scope of simulations are briefly explained. Afterwards, the outcomes of the power system analysis of the different conceptual offshore network designs for 2050 are compared.

3.1 Approach

A summary of the main inputs, modelling assumptions and scope of simulations for the sensitivity analysis is provided below.

3.1.1 Inputs

- Simulation model of the GB transmission system for the year 2028, from ESO's ETYS 2019 report.
- Offshore wind capacity per flop zone, annual wind load factors and interconnector load factors for the years 2025-2050, in accordance to the LW scenario, as described in the ESO's FES 2020 report.
- Onshore landing points and active power injections for the counterfactual and integrated designs.

3.1.2 Modelling Assumptions

- The simulation model has been updated to include the offshore wind capacity forecasted between the years 2028-2050 (see Appendix A).
- The peak demand for the year 2050 is set to 60 GW (+30% with respect to 2028). This growth percentage is similar to the forecast for the LW scenario, as indicated in the FES 2020 report.
- The new offshore wind capacity was modelled as active power injections, corresponding to 70% of the installed wind capacity (i.e. SQSS economy dispatch).
- In the integrated offshore network designs, the power transferred via interlinked HVDC connections was distributed between landing points as to produce the largest benefit on the onshore boundaries.
- The reactive power injection of the new offshore wind capacity was set to zero. Furthermore, future compensation equipment was not included, whilst existing quadrature boosters were not optimised.

3.1.3 Scope of Simulations

The model of the conceptual offshore network designs was limited to power flow studies and intended to demonstrate the impact of the power injections on the onshore system. For 2050, the DC flow calculation was used (i.e. only active power considered), to resolve convergence issues with the AC flow calculation.

3.2 Analysis per Regional Zone

3.2.1 Active Power Injections

For each of the regional zones, the main differences between the active power injections modelled for the Counterfactual, Integrated (Start 2030) and Integrated (Start 2025) scenarios are explained next.

North Scotland

In North Scotland, the active power injection at Beauly and Peterhead in the Integrated (Start 2030) design follow a similar pattern as in the Counterfactual. The power at Beauly comes from the Western Isles via an HVDC interconnector, whilst the injection at Peterhead is realised via an HVDC interconnector between Spittal-Peterhead. The active power injections correspond to wind capacity installed between 2025-2030.

From all the power that reaches the Kintore area, the Cottam and Drax interconnectors are loaded as close as possible to the maximum in both the Integrated (Start 2030) and Integrated (2025) designs, while the remainder power flows via Kintore. Finally, the active power injection at Keith is the same in all the scenarios and it is realised via HVAC.

Table 3-1 Active power injections for North Scotland in 2050.

		Offshore Wind Power Injection [MW]		
Substation		**Counterfactual**	**Integrated (Start 2030)**	**Integrated (Start 2025)**
Beauly	T1	520	520	–
Kintore	T2	–	1,450	2,600
Peterhead	T2	1,750	1,600	770
Spittal	T5	5,700	280	–
Keith	T6	1,300	1,300	1,300
Cottam	K5	–	3,600	3,600
Drax	P4	1,580	2,100	2,580
Total		10,850	10,850	10,850

East Scotland

In East Scotland, the power injections in Cockenzie-Torness and Blyth-Lackenby add up to the same total in both the Integrated (Start 2030) and Integrated (Start 2025) designs. Nonetheless, the topology of the connections differs due to the start of integration in 2030. In the Integrated (Start 2030) design, an extra reinforcement is required between Blyth-Lackenby (1.32 GW HVDC monopole) to be able to redistribute a portion of the infeed offshore wind power towards Lackenby.

Table 3-2 Active power injections for East Scotland in 2050.

		Offshore Wind Power Injection [MW]		
Substation		**Counterfactual**	**Integrated (Start 2030)**	**Integrated (Start 2025)**
Cockenzie	S6	1,980	500	850
Torness	S6	2,570	1,450	1,100
Blyth	Q4	–	1,750	2,600
Lackenby	Q2	–	850	–
Total		4,550	4,550	4,550

Dogger Bank

In the Dogger Bank region, the active power injection at Creyke Beck and Keadby in the Integrated (Start 2030) design is the same as in the Counterfactual, since it belongs to the time period between 2025-2030. However, the power injected at Keadby is further redirected to Walpole via an additional reinforcement (2.64 GW HVDC interconnection) that it is not required in the Integrated (Start 2025) design. Meanwhile, the active power injection at Killingholme and Lackenby in the Integrated (Start 2030) design is the same as in the Integrated (Start 2025) design, since the offshore wind capacity is planned between 2030-2050.

Table 3-3 Active power injections for the Dogger Bank in 2050.

		Offshore Wind Power Injection [MW]		
Substation		**Counterfactual**	**Integrated (Start 2030)**	**Integrated (Start 2025)**
Killingholme	P7	–	1,110	1,100
Creyke Beck	P8	520	520	–
Keadby	P8	1,300	–	–
Lackenby	Q2	2,590	1,480	1,480
Walpole	J1	–	1,300	1,820
Total		4,410	4,410	4,410

Eastern Regions

In the Eastern Regions, the active power injection at Bramford and Necton in the Integrated (Start 2030) design is the same as in the Counterfactual, since it is planned between 2025-2030. Meanwhile, the power injection at Norwich Main is greatly reduced but not to the same extent as in the Integrated (Start 2025).

In similar fashion to the Integrated (Start 2025) design, the power injection at Tilbury, Grain and Kemsley is maximised to benefit the onshore boundaries. However, to achieve this in the Integrated (Start 2030) design, new reinforcements are required. These are realised via a 2.64 GW HVDC link between Sizewell-Kemsley and another 2.64 GW HVDC link between Walpole-Grain.

Table 3-4 Active power injections for the Eastern Regions in 2050.

		Offshore Wind Power Injection [MW]		
Substation		**Counterfactual**	**Integrated (Start 2030)**	**Integrated (Start 2025)**
Walpole	J1	1,700	–	1,420
Bramford	J2	600	600	600
Sizewell	J2	850	–	600
Necton	J3	650	650	–
Norwich Main	J3	5,900	1,138	–
Killingholme	P7	2,500	–	–
Tilbury	C1	–	1,847	1,600
Grain	C3	–	4,600	4,600
Kemsley	C3	–	2,610	2,610
Sellindge	C4	–	378	560
Richborough	C7	–	378	210
Total		12,200	12,200	12,200

South East

In the South East, the power injections in the Integrated (Start 2030) follow the same distribution as in the Counterfactual design. This leads to minor impact on the onshore system with respect to the Integrated (Start 2025) design, due to the low offshore wind capacity to be connected directly to this region.

Table 3-5 Active power injections for the South East in 2050.

		Offshore Wind Power Injection [MW]		
Substation		**Counterfactual**	**Integrated (Start 2030)**	**Integrated (Start 2025)**
Richborough	C7	210	210	490
Bolney	B1	280	280	–
Total		490	490	490

North Wales and Irish Sea

In the North Wales and Irish Sea region, 1.00 GW and 11.78 GW offshore wind capacity are to be connected between 2025-2030 and 2030-2050 respectively. The capacity connected between 2025-2030 is reflected in the Integrated (Start 2030) design with a 0.70 GW power injection at Pentir, which was not present in the Integrated (Start 2025) design. For the extra capacity between 2030-2050, both Integrated designs share the same landing points. The HVDC links to the South Wales are loaded to maximum, whilst the HVDC links to North Wales take on the remainder power injection.

In this region, the Integrated (Start 2030) achieves a similar performance to the Integrated (Start 2025) without having to implement any additional reinforcements. The "outer loop" between this offshore area and Cilfyndd 400kV is now some 3.6GW in scale however to address a higher level of direct project by project connection into North Wales by 2030.

Table 3-6 Active power injections for North Wales and Irish Sea in 2050.

		Offshore Wind Power Injection [MW]		
Substation		**Counterfactual**	**Integrated (Start 2030)**	**Integrated (Start 2025)**
Pentir	M6	1,900	700	–
Wylfa	M8	3,700	1,320	1,320
Birkenhead	N3	3,350	–	–
Penwortham	R4	–	1,515	1,865
Heysham	R5	–	1,515	1,865
Cilfynydd	H6	–	2,580	2,580
Pembroke	H6	–	1,320	1,320
Total		8,950	8,950	8,950

3.2.2 Boundary Power Transfers

Boundary capacity is one of the main factors that can influence the operation of the onshore transmission system of GB and the associated planning needs for the future. For each of the considered regional zones, the calculated onshore boundary power transfers in 2050 are indicated in Table 3-7. The provided figures allow to quantify the benefits brought by the Integrated designs to the onshore transmission system with respect to the Counterfactual design.

From the results of the analysed boundaries, it can be observed that the Integrated (Start 2030) design also provides significant improvements when compared to the Counterfactual design. Nonetheless, the benefits do not reach the same extent as in the original Integrated (Start 2025) design. Furthermore, in order to achieve these benefits in the Integrated (Start 2030) design, several new reinforcements are required, as already indicated during the description of the active power injections per regional zone.

Further information about the loading levels of the relevant transmission lines are provided in Appendix B. Once more, the results of the Integrated (Start 2030) and Integrated (Start 2025) designs are comparable.

Table 3-7 Simulation results for boundary power transfers in 2050.

	Boundary Power Transfer Year 2050 [GW]				
	Counterfactual	**Integrated (Start 2030)**		**Integrated (Start 2025)**	
North Scotland					
B0	7.29	0.82	-89%	0.93	-87%
B1a	8.69	3.67	-58%	2.89	-67%
B2	11.44	7.56	-34%	7.14	-38%
East Scotland					
B6	14.86	8.24	-45%	7.24	-51%
Dogger Bank					
B7	18.86	13.73	-27%	12.73	-33%
B8 (Keadby path only)	14.99	10.22	-32%	8.71	-42%
Eastern Regions					
B9	20.38	15.38	-25%	12.16	-40%
EC5	6.93	3.48	-50%	2.29	-67%
South East					
SC1	9.05	8.74	-3%	8.48	-6%
SC3	3.72	7.10	+91%	7.76	+109%
North Wales and Irish Sea					
B7a (Penwortham area only)	3.72	4.68	+26%	5.00	+34%
NW1	3.67	1.29	-65%	1.29	-65%
NW3	4.43	0.94	-79%	0.46	-90%
SW1	2.92	3.03	+4%	2.93	+0%

4 COST BENEFIT ANALYSIS

The cost benefit analysis (CBA) conducted within this sensitivity study is exploring what are the socio-economic impacts of shifting the starting year of integration from 2025 to 2030. In the original analysis which can be found in our CBA report[5], it was discovered that the Integrated grid design, if being developed from 2025, can bring substantial benefits for the society, especially in terms of reduced investment cost but also in terms of smaller environmental and social impacts.

4.1 Assumptions and scope

In this sensitivity study CBA follows the same framework and assumptions as described in the original report and builds on the same unit cost data.

The only difference between this and the original study is that not all Key Performance Indicators (KPIs) are valued. Originally the following KPIs were evaluated to determine which offshore grid development paradigm is more socio-economically optimal.

Table 4-1 KPI overview from the original study

Monetised	Quantified	Qualified
System costs	RES (Renewable Energy Sources) Integration	Security of supply - Adequacy
CAPEX (capital expenditure)	Carbon intensity	Security of supply - Security
OPEX (operational expenditure)	Grid losses	Security of supply - Resilience
		Environmental impacts
		Social and Local impacts

Due to the fact that the outcomes of the original study showed sensible difference only for some of them, we will limit our scope to the following KPIs within this study:

1. Capital expenditure (CAPEX)
2. Operational expenditure (OPEX)
3. Environmental and Social impacts (based on the number and total area of onshore landing points)

We assume that as in the original study, the other KPIs will have only negligible, if any, difference between the Counterfactual and the newly obtained Integrated alternatives.

[5] Cost-Benefit Analysis of Offshore Transmission Network Designs (DNV GL, National HVDC Centre, EPNC; 2020). https://www.nationalgrideso.com/future-energy/projects/offshore-coordination-project/documents

4.2 Valuation

4.2.1 Summary of results

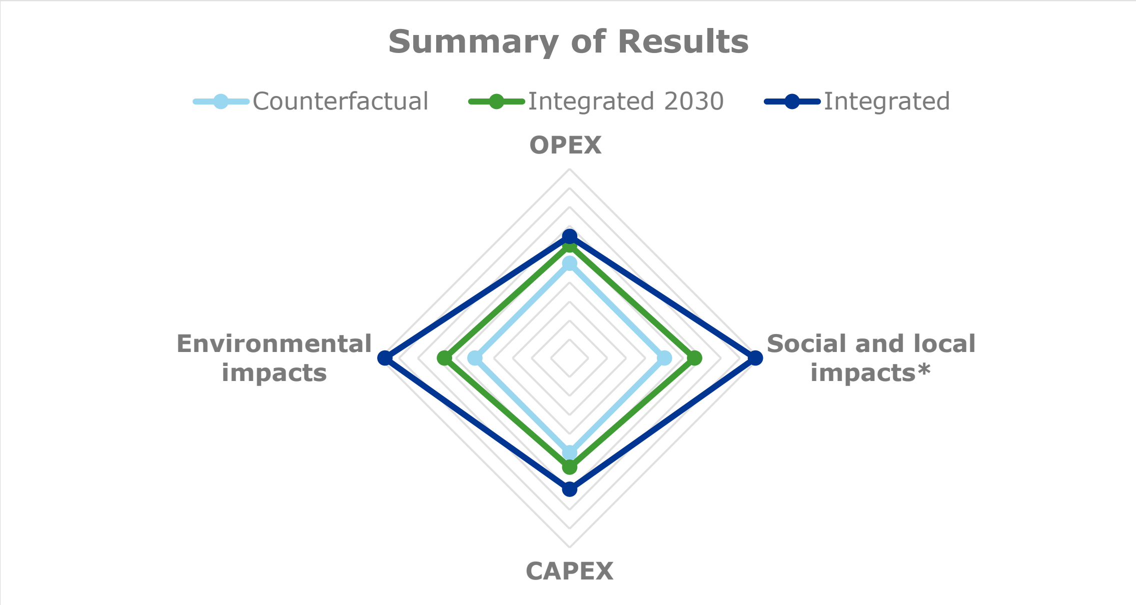

Figure 4-1 Summary of valuation results for selected KPIs (by how much in % the Integrated designs score better than the Counterfactual)

As it can be seen from Figure 4-1 and Table 4-2, the newly obtained Integrated design (Integrated 2030) whereby integration begins in 2030 is more beneficial than the Counterfactual but has roughly half of the benefits that could be delivered if integration began in 2025 (Integrated). Notably, the monetary savings in CAPEX and OPEX are more than halved, while the number and area of onshore connection points is even closer to the Counterfactual, implying lost benefits for the local communities and environment.

Table 4-2 Summary of valuation results for selected KPIs

KPI	Counterfactual (C)	Integrated (I)	Integrated 2030 (I2030)	Difference	
				(C-I) %	*(C-I2030) %*
CAPEX MGBP	29,000	23,399	26,798	19%	8%
OPEX MGBP	7,113	6,097	6,429	14%	10%
(CAPEX + OPEX) MGBP	36,113	29,496	33,227	18%	8%
Environmental impacts	Onshore area = 386 ha 100% landing points	Onshore area = 173 ha 40% landing points	Onshore area = 310 ha 60% landing points	50%	30%
	100% offshore cables 100% onshore cables/lines	65% offshore cables 40% onshore cables/lines	90% offshore cables 73% onshore cables/lines		
Social and local impacts	100% lines/cables 100% substations	40% lines/cables 40% substations	80% lines/cables 60% substations	60%	30%

4.2.2 Costs

In this section cost related KPIs are reported. These include CAPEX and OPEX of the 3 grid designs – Counterfactual, Integrated with the beginning of integration in 2030 (Integrated 2030), and originally developed Integrated (Integrated). Table 4-3 provides a summary of the obtained costs where it is also shown by how much in percentage the two Integrated designs are cheaper than the Counterfactual.

Table 4-3 Lifetime comparison of the discounted costs of the Counterfactual, Integrated 2030 and Integrated designs (values in M£)

	Counterfactual		Integrated		%	Integrated 2030		%
CAPEX	£	29,000	£	23,399	19%	£	26,798	8%
OPEX	£	7,113	£	6,097	14%	£	6,429	10%
Total	**£**	**36,112**	**£**	**29,946**	**18%**	**£**	**33,327**	**8%**

4.2.2.1 CAPEX

Summary

CAPEX of the Integrated design with the starting year of integration in 2030 is 8% lower than that of the Counterfactual. For comparison, the reduction in CAPEX for the Integrated design, if started in 2025, is 19% according to our original assessment. As it was the case previously, the magnitude of the savings varies per region, hence we present an overview on the regional basis in Figure 4-2.

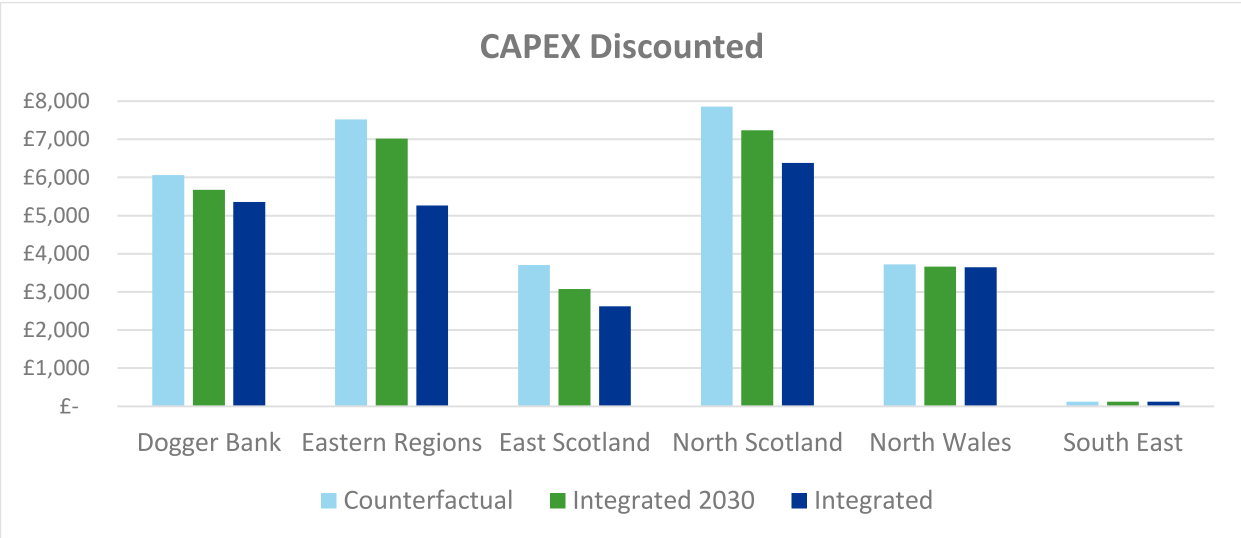

Figure 4-2 CAPEX comparison of Counterfactual, Integrated 2030 and Integrated per offshore wind region (values in M£)

Explanation

Table 4-4 shows underlying data on a reginal basis indicating the reduction between the two Integrated designs and the Counterfactual in percentage.

Table 4-4 CAPEX comparison of Counterfactual and Integrated 2030 and Integrated per offshore wind region (values in M£)

	Counterfactual		Integrated		%	Integrated 2030		%
Dogger Bank	£	6,064	£	5,355	12%	£	5,675	6%
Eastern Regions	£	7,521	£	5,263	30%	£	7,016	7%
East Scotland	£	3,709	£	2,623	29%	£	3,077	17%

North Scotland	£	7,859	£	6,382	19%	£	7,241	8%
North Wales	£	3,720	£	3,650	2%	£	3,663	2%
South East	£	126	£	126	0%	£	126	0%
Total	**£**	**29,000**	**£**	**23,399**	**19%**	**£**	**26,798**	**8%**

Based on the data presented in Table 4-4 we see that the Integration starting in 2030 has different relative effect between the regions. In the North Wales and South East regions there is minor difference observed. This can be partially attributed to the isolated nature of these regions or relatively smaller amounts of installed wind. In these areas the new integrated designs are quite similar to the original ones implying that the opportunity for integration is little and is not missed due to later beginning.

For Dogger Bank, Eastern Regions, North and East Scotland integration starting in 2030 has adverse impact on the level of savings. The reason is that significant part of the newly built wind capacity is commissioned in the years between 2025 and 2030 (see Figure 1-1). Thus, the opportunity to significantly reduce investment costs is missed and eventual savings in CAPEX are about halved.

Comparison per year

In this subsection an overview of CAPEX distribution on component level is given on a yearly basis. Figure 4-3 represents year-on-year difference in capital expenditures between the Counterfactual and newly obtained Integrated, with the starting year of integrating in 2030. Where the difference is positive, it means that the total cost of components in this type is higher in the Counterfactual case. In other words, this graph is the difference between the data from Figure 4-5 and in Figure 4-4.

This chart clearly shows that the Counterfactual employs much more HVAC equipment while Integrated features more HVDC cables and offshore platforms which are the main drivers behind its cost.

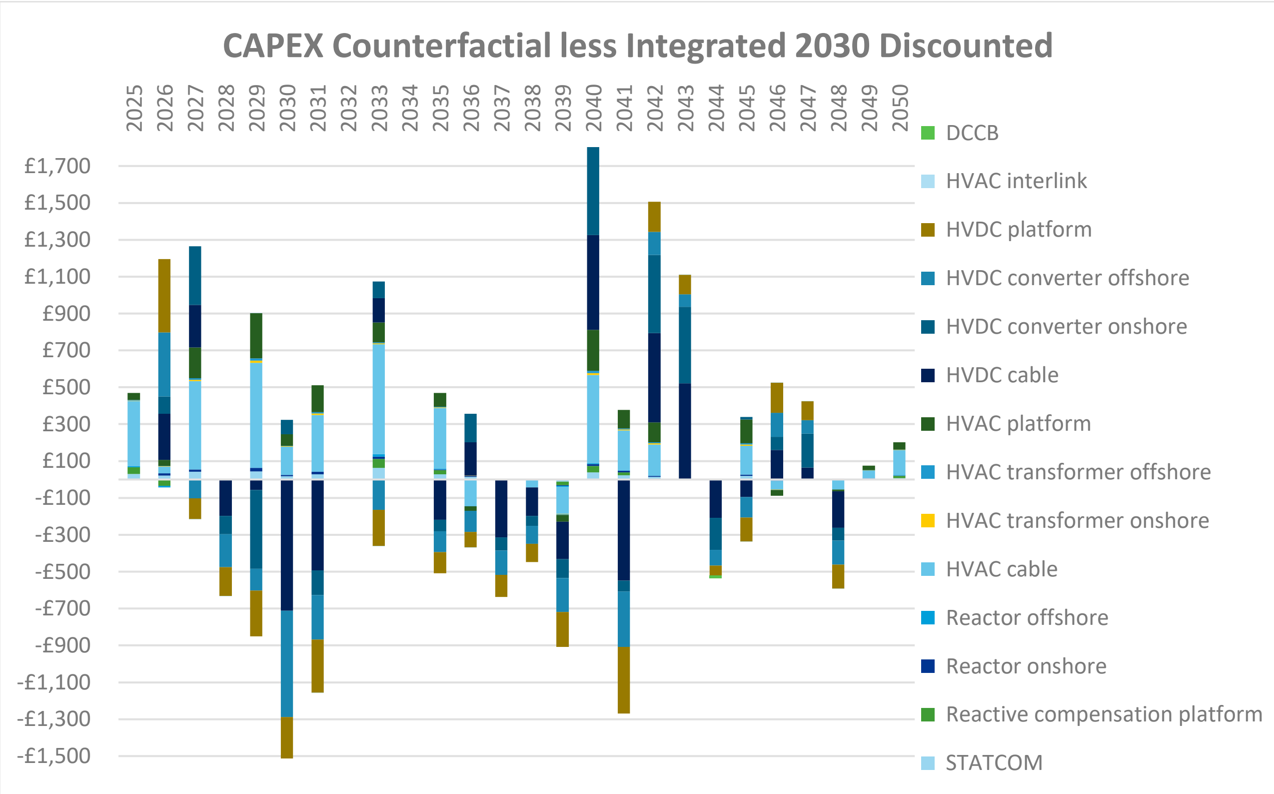

Figure 4-3 CAPEX Counterfactual less Integrated 2030 per year (values in M£)

Figure 4-4 is the outcome of this sensitivity analysis and demonstrates year-on-year CAPEX for the Integrated with the starting year in 2030. The same pattern as in the Counterfactual and original Integrated can be observed: high level of expenditures between 2025 and 2030 with another peak after 2039. This is direct outcome of how wind capacity is rolled out according to LW FES scenario.

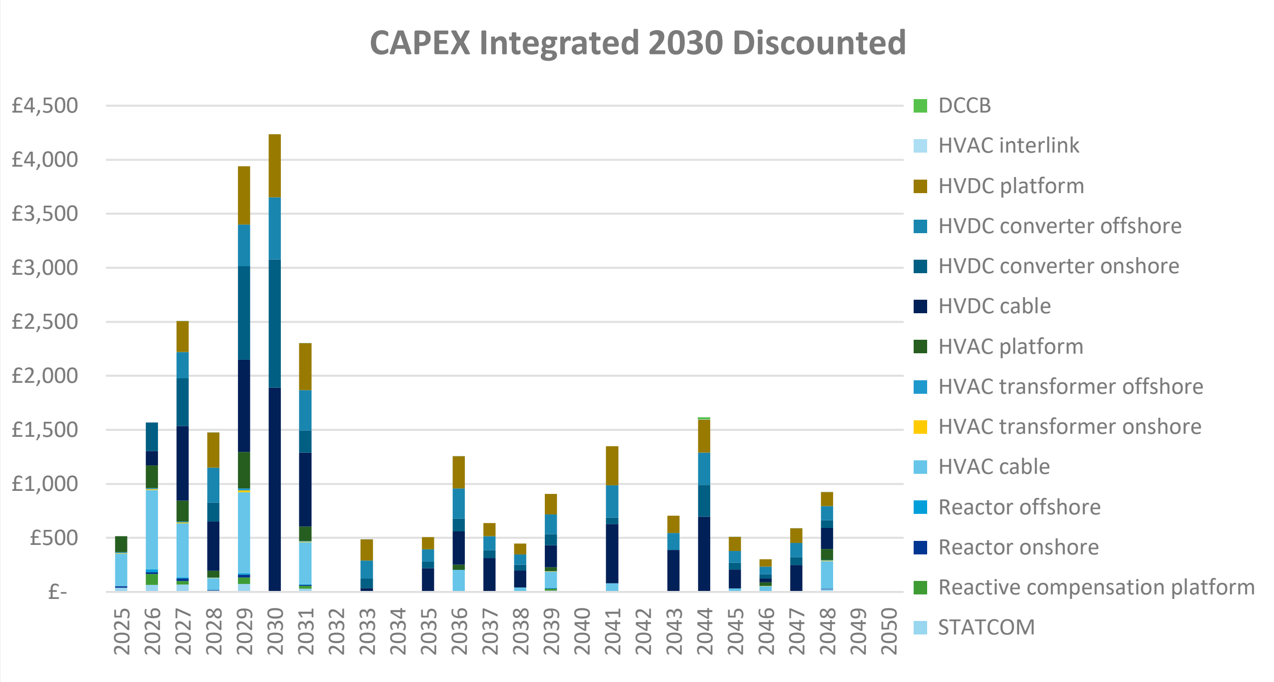

Figure 4-4 CAPEX Integrated 2030 per year (values in M£)

Figure 4-5 is taken from the original study and shows how capital expenditure is spread over the years in the Counterfactual approach.

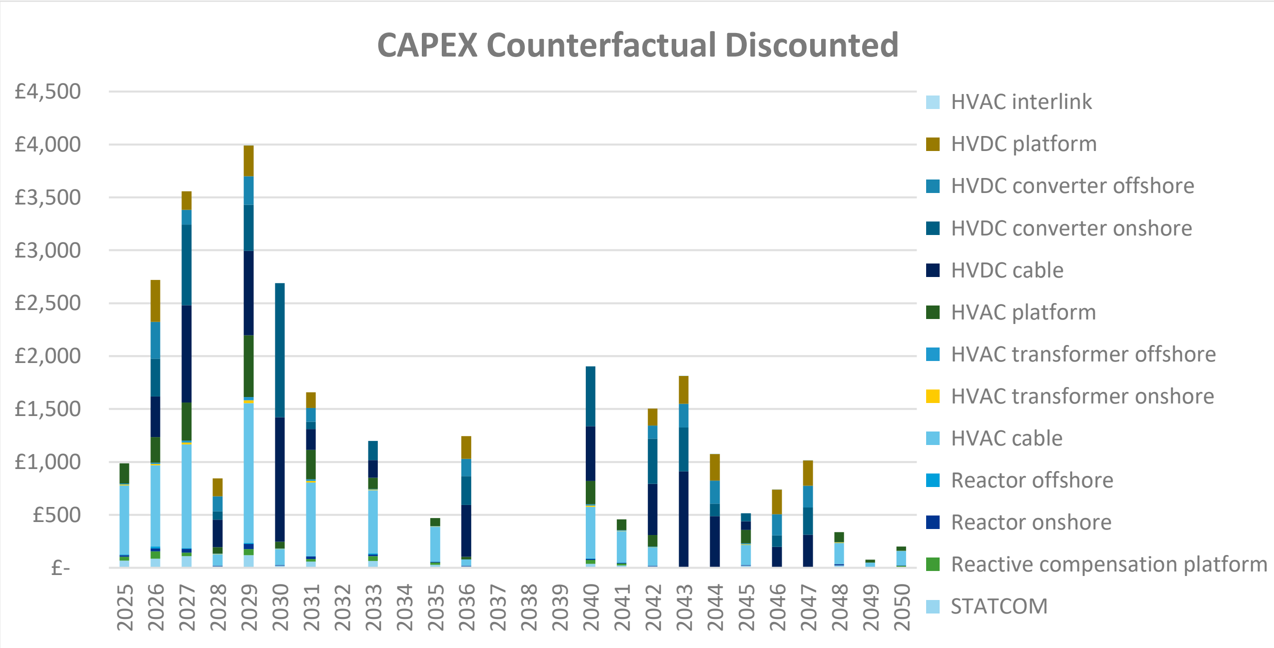

Figure 4-5 CAPEX Counterfactual per year (values in M£)

Similarly, Figure 4-6 represents the same information from the original study for the Integrated with the starting year in 2025.

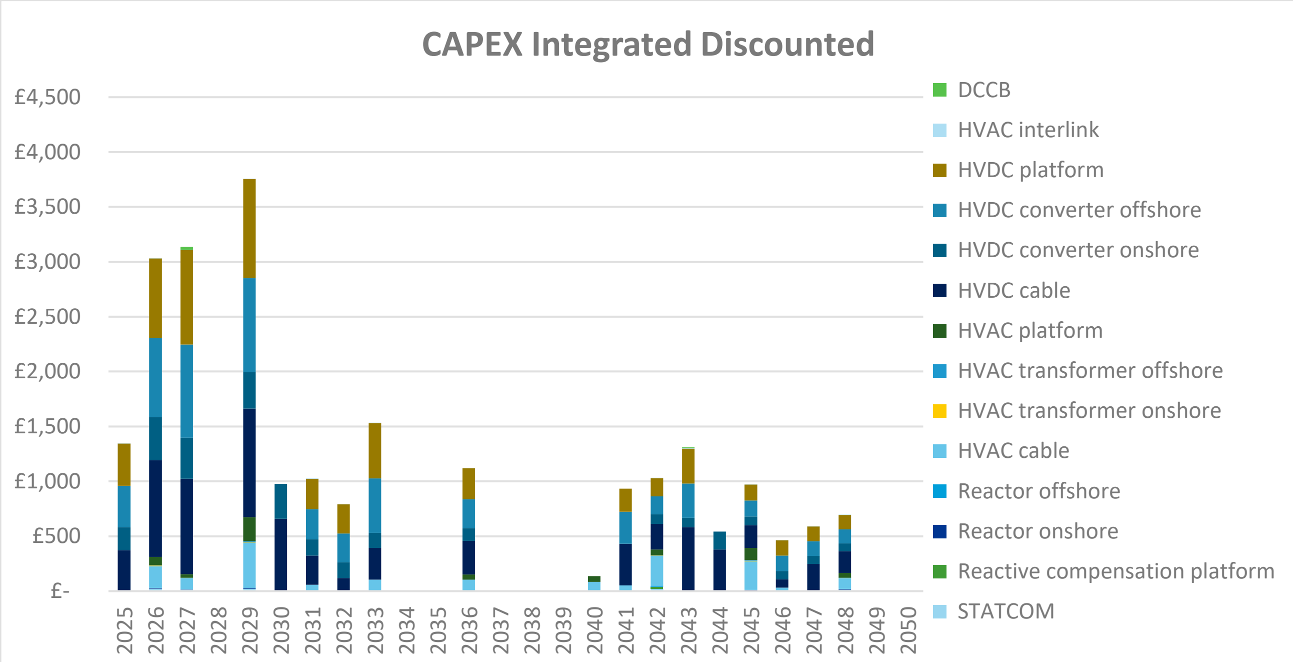

Figure 4-6 CAPEX Integrated 2025 per year (values in M£)

Comparison per offshore wind region

In this subsection we give an overview of how CAPEX is distributed between different types of components on the regional basis.

Figure 4-7 is similar to Figure 4-3 in the information that it conveys. On a regional basis it shows which types of technologies prevail in the Counterfactual and newly obtained Integrated designs. It shows a difference between the data from Figure 4-9 and Figure 4-8.

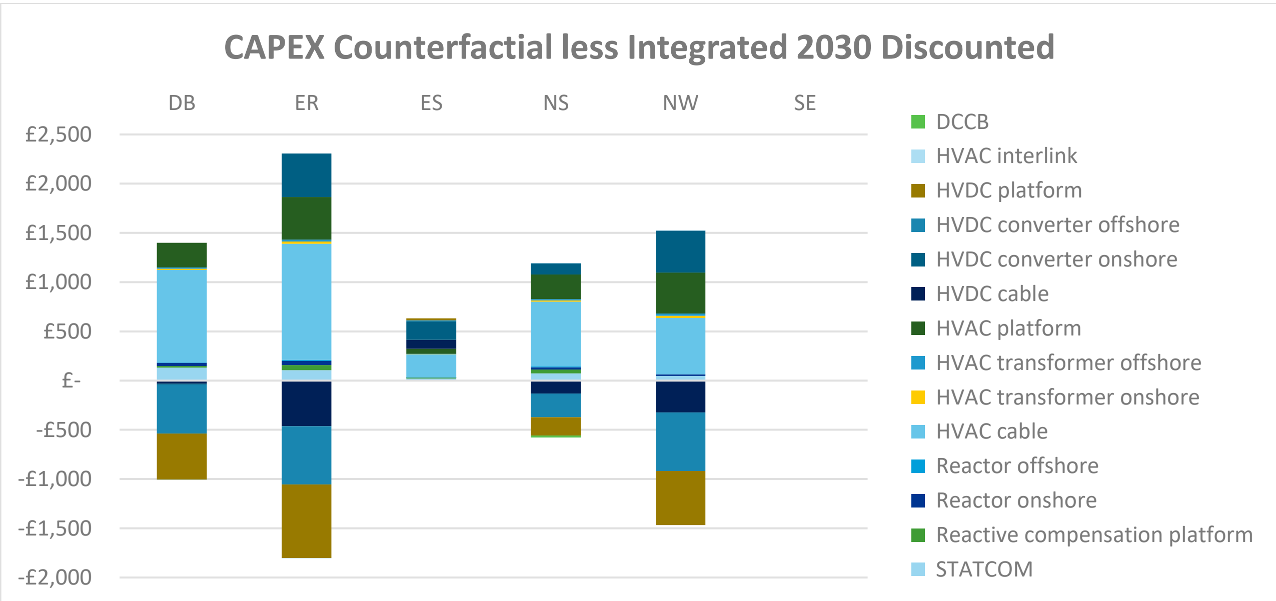

Figure 4-7 CAPEX Counterfactual less Integrated 2030 per region (values in M£)[6]

[6] DB – Dogger Bank, ER – Eastern Regions, ES – East Scotland, NS – North Scotland, NW – North Wales, SE – South East.

It can be seen that certain regions such as Dogger Bank, Eastern Regions and North Wales, albeit having similar total cost, vary a lot in terms of which type of connections, namely HVDC or HVAC, they primarily feature. For East Scotland, in contrary, there is more components of all types in the Counterfactual. The explanation is that within the newly obtained Integrated design a more effective use of transmission capacity is achieved. By not building individual connections for each increment in wind capacity but rather by aggregating and delivering grid in anticipation of wind roll out, one can reduce the overall cost for this region. As in the original study, South East region employs absolutely similar grid designs due to low total wind capacity, hence nothing is shown opposite to 'SE' on the chart.

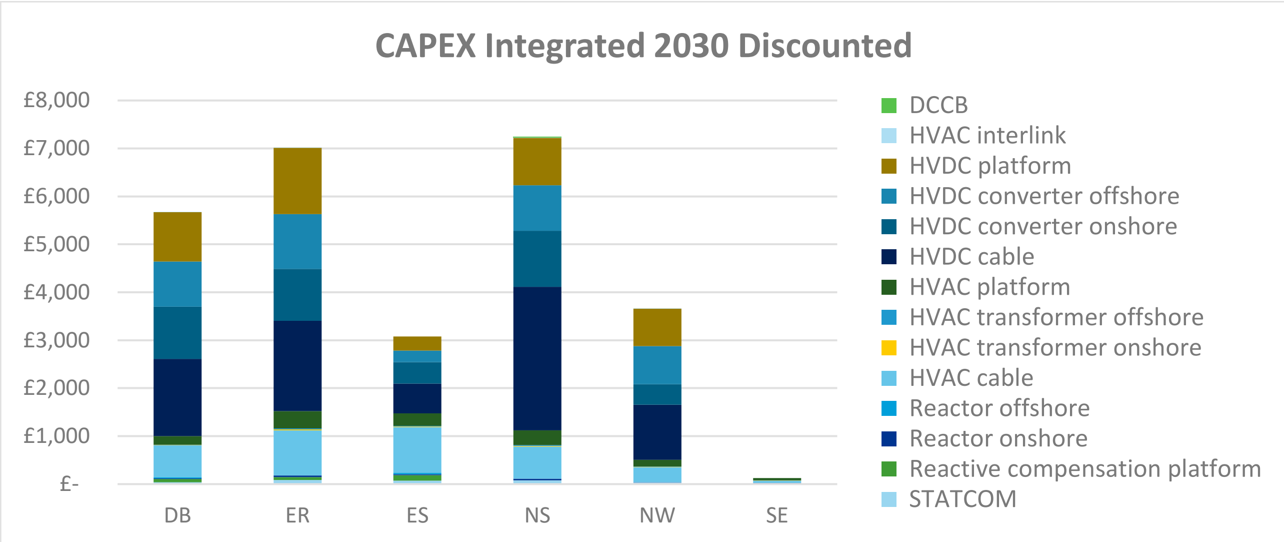

Figure 4-8 CAPEX Integrated 2030 per region (values in M£)

Figure 4-8 shows the newly obtained distribution of CAPEX in the Integrated with the starting year of integration in 2030.

Figure 4-9 and Figure 4-10 are taken from the original analysis and show CAPEX distribution for the Counterfactual and for the Integrated case with the beginning of integration in 2025 respectively.

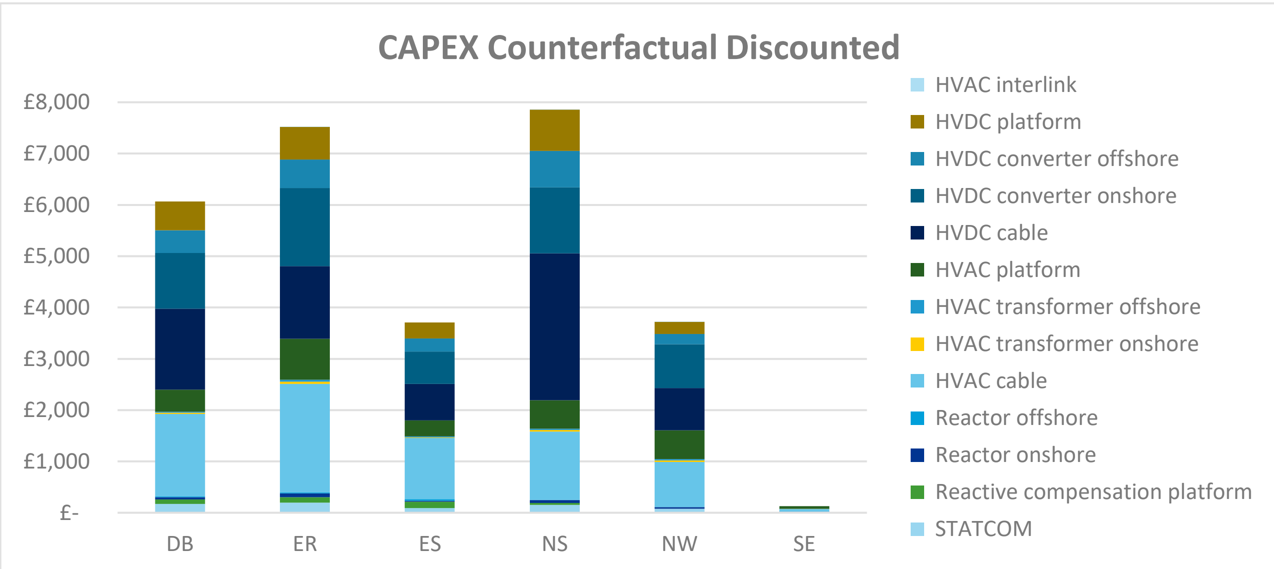

Figure 4-9 CAPEX Counterfactual per region (values in M£)

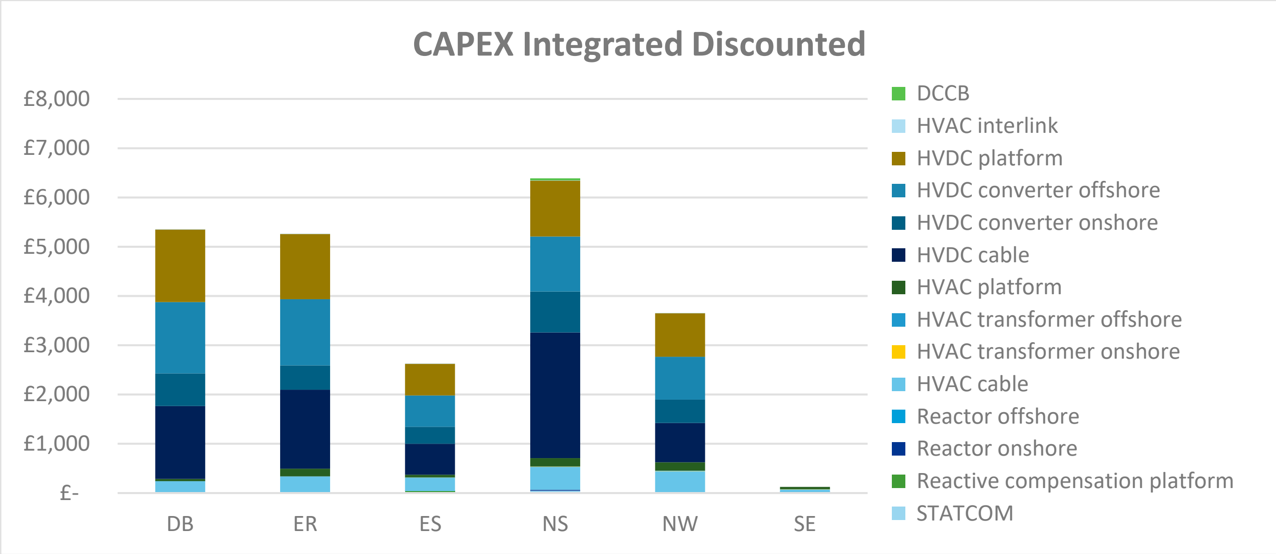

Figure 4-10 CAPEX Integrated 2025 per region (values in M£)

These charts clearly indicate that in terms of installed assets and technology type the newly obtained Integrated design with the start date in 2030 is a mixture between the original Counterfactual and the original Integrated – it is still more HVDC heavy than the Counterfactual but features more HVAC connections than the original Integrated.

4.2.2.2 OPEX

Summary

Lifetime OPEX for the newly obtained Integrated design became higher that it was for the original Integrated and delivers 10% of savings instead of 14% as compared with the Counterfactual. OPEX is 23% of CAPEX if integration is started from 2030. Table 4-5 gives an overview of the actual values and relative difference between the Counterfactual and two Integrated designs in percentage.

Table 4-5 OPEX comparison of Counterfactual, Integrated and Integrated 2030 (values in M£)

	Counterfactual	Integrated	%	Integrated 2030	%
OPEX	£ 7,113	£ 6,097	14%	£ 6,429	10%

Explanation

The year-on-year cashflow of OPEX payments for the grid maintenance and operation is visualised in Figure 4-11. At the inception, between 2025 and 2029 the newly obtained Integrated incurs operational expenditure that are below those of the Counterfactual and original Integrated design. From 2030 a higher pace of grid roll-out is observed and operational expenditures grow, sometimes exceeding those for the Counterfactual. From 2033 onwards the newly obtained Integrated remain between the Counterfactual and original Integrated up until 2045 where it sometimes becomes lower.

We note that the below shown pattern should not be treated as exact projection of year-on-year development of OPEX. Based on the FES LW scenario assumptions were made with regard to when offshore grid needs to be constructed to accommodate wind capacity increments, uncertainty in commissioning time of 1 year is possible for some of the connections. We do not recommend to study this graph for exploring exact OPEX values in a concrete year, but rather to treat it as a generic visualisation of how OPEX costs evolve throughout the whole period from 2025 to 2050 and build up to the total value indicated in Table 4-5.

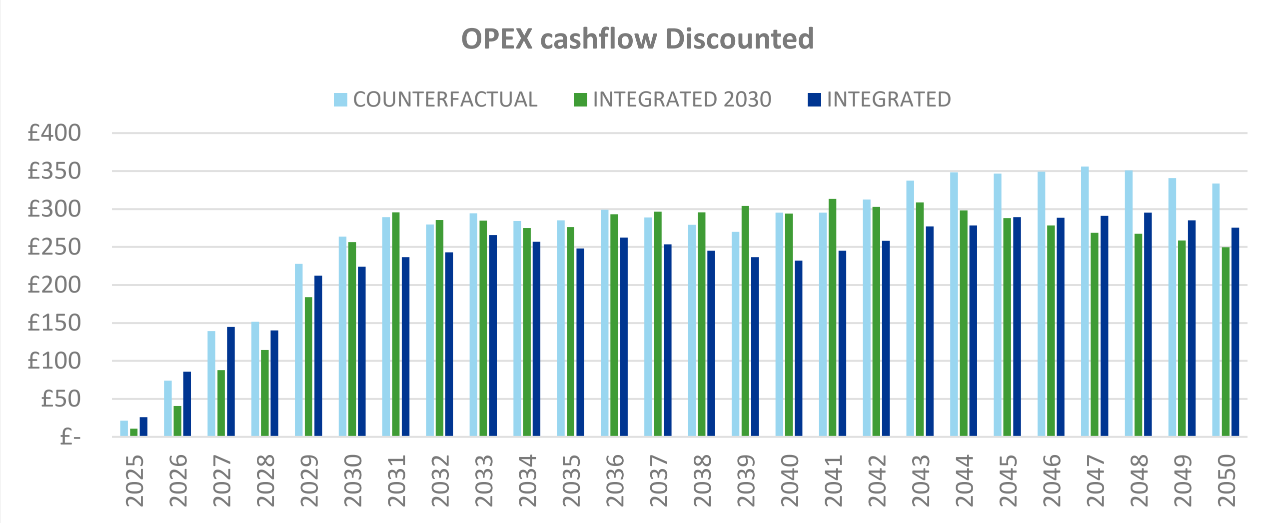

Figure 4-11 OPEX comparison of Counterfactual, Integrated 2030 and Integrated per year (values in M£)

4.2.3 Social and Environmental impacts

Summary

Social and environmental impacts are considered as long as they are a direct consequence of the construction works and visual impacts caused by the deployment of substations onshore. We conclude that starting integration in 2030 has significant adverse effect on the level of improvement in social and environmental impacts that integration could bring otherwise, if started from 2025.

Table 4-6 Estimate of total landing points' area (in hectares)

Integrated	Integrated 2030	Counterfactual
173	310	386

For a better comprehension we visualise the ratio of these areas in Figure 4-12.

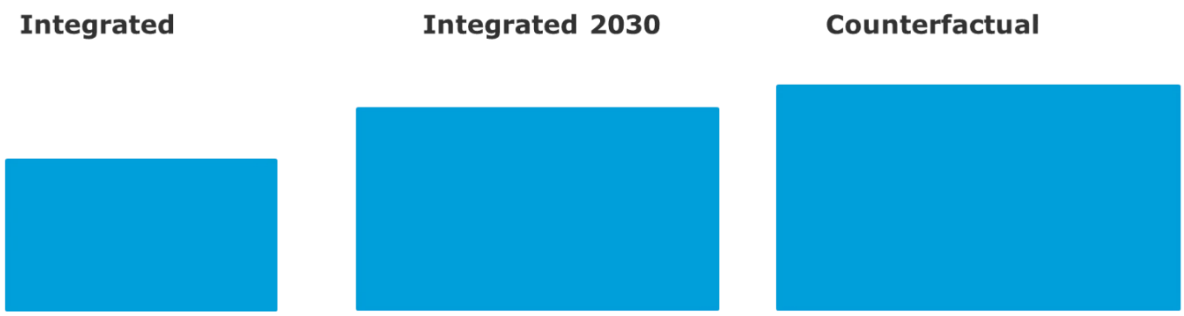

Figure 4-12 Visualisation of the onshore area requirements

Considering connections, note that some of them may consist of several cables running in parallel and effectively connecting one wind farm to one onshore substation. Therefore, the reported number correspond to the sum of distances between offshore and onshore connection points rather than to the total cable length which would be much higher for both designs.

Table 4-7 Total connection length (in km)

	Counterfactual	Integrated	Integrated 2030
Offshore cables trenches	8225	5450	7385
Onshore cables / HV overhead connections	3360	1285	2465

Explanation

Onshore area requirements

Within our original assessment we have concluded that the Integrated design requires significantly lower number of onshore landing points as compared with the Counterfactual in order to evacuate a given amount of offshore energy. With the integration year becoming 2030, this number increased although still remained much lower than that of the Counterfactual. This is presented in Table 4-8.

Table 4-8 Number of landing points

Counterfactual	Integrated	Integrated 2030
105	30	63

As the number of onshore landing points is reduced, so will be the detrimental impacts on the environment during construction and operational phases[7]. However, it is not enough to only assess the number of substations. Seeing that the underlying technology differs between the two alternatives, the size of the assets will be different as well, resulting in the space requirements difference which is not necessarily proportional to the absolute number of substations. Based on the data from comparable global projects we have investigated what would be the onshore space requirements to accommodate the substation infrastructure. This is presented in Table 4-9.

Table 4-9 Comparison of onshore area requirements

	Typical capacity GW	Voltage kV	Area ha[8]	Number	Total area ha
Counterfactual					
HVDC substations	1.8	525	5	57	285
HVAC substations	0.8	220	2.1	48	100.8
Total area					**385.8**
Integrated					
HVDC substations	2.64	525	8[9]	20	160
HVAC substations	0.8	220	2.1	6	12.6
Existing interconnector HVDC	-	-	-	4	-
Total area					**172.6**
Integrated 2030					
HVDC substations	2.0	525	7[10]	38	266
HVAC substations	0.8	220	2.1[11]	21	44.1
Existing interconnector HVDC	-	-	-	4	-
Total area					**310.1**

7 Within our original analysis we used the number of onshore landing points as a simple proxy for the assessment of environmental and social impacts.

8 1 hectare (ha) = 0.01 square kilometers (km^2) = 1.4 football pitch

9 Based on information available from the Chinese Zhangbei project

10 Based on information available from the North Sea Link, Nordlink projects in UK, Norway and Germany

11 Scaled down form Hornsea 1 project (1200 MW)

5 CONCLUSIONS

For this sensitivity study, counterfactual and integrated design approaches developed and used were consistent with those discussed in the Holistic Approach to Offshore Transmission Planning report. This supplementary sensitivity study assessed the potential impacts of a change to the implementation date for integrated offshore network design from 2025 to 2030.

A modified integrated network design approach was developed for this study that treated capacity connected prior to 2030 on a project specific offshore connection basis and new capacity from the 1st January 2030 connecting to shared flexible and coordinated integrated infrastructure offshore.

Based on the FES2020 LW scenario, our sensitivity study results identify a potential direct impact on 24.5 GW of offshore development between 2025 and 2032 with:

- 17.1 GW of this capacity being connected (between 2025 and 2030) on a project specific basis, and
- 7.4GW of capacity being connected (between 2030 and 2032) by transitional solutions suitable to be adapted to integrated offshore network design solutions.

The potential impacts that these design choices would be expected to have on the environmental outcome of the solution is highlighted in this report. In comparison to the original integrated approach analysis, a 40-60% increase in the level of assets that need to be installed by 2030. From an overall impact in 2050 perspective, a 20-30% increase in the level of assets that need to be installed would be expected. The illustrative designs and regional asset count in this report illustrate that the identified potential impacts follow the areas (including Eastern Regions, Dogger Bank and North of Scotland), where most early growth in offshore is expected and/or is already taking place. However, it is noted that all regions would be impacted by a later implementation date for integrated offshore transmission network designs.

For this sensitivity (integrated offshore network design implemented from 2030), the results from the power system analysis show power flows within onshore transmission system boundaries that are higher than the capability of onshore transmission system (taking account of reinforcements identified as part of the 2020 Network Options Assessment process) as well as the power flow results discussed in the Holistic planning report (integrated offshore network design implemented from 2025).

The higher onshore power flows that need to be addressed up to 2030 by the indicative extra onshore reinforcements considered as part of this sensitivity study, also present a different power system problem for the integrated solutions that then follow. This is expected to mean that the first transition projects would have different solutions than previously assessed and present less opportunity for optimal integration than was previously identified.

The results of this study illustrate that beyond 2032, integrated offshore network design solutions would need to be operated in combination with the earlier counterfactual onshore reinforcements up to 2030 in order to deliver similar onshore boundary power flow solutions by 2050 which again meet onshore system security need. To achieve this, the earlier reinforcements need to be fully utilized together with integrated solutions focusing differently across landing points, and in limited cases with increased capacity of power cables and converters being used. Otherwise, an approach has been adopted that was as similar as possible. Overall, this presents a more complex operational picture in order to achieve the previous outcome but does mean in respect of power system performance that the 2030 sensitivity would be expected to deliver an equivalent overall outcome for the total transmission system as the earlier integrated design.

CBA results show that the area required for onshore infrastructure overall remains over 80% that of the previous area noted in counterfactual, and the number of onshore substations over 60% of that required for the counterfactual, and as such the overall benefits environmentally from the 5 year later start in implementation have declined significantly. Finally, we note that the overall benefit of integration falls to some £3bn by 2050 when starting integration in 2030, being a combination of OPEX cost increase over the period in comparison to the original integrated solution (more assets than before being the principal reason), and a higher capital cost (from more costly revised integrated solutions combined with an early use of counterfactual solutions).

Finally, we would note that the data presented in this report arises from our analysis of an implementation date for integrated offshore network design that is 5 years later than that assumed for the original study. The report does not seek to discuss how, ahead of the changes/ frameworks/processes noted in our original report recommendations activity in delivering integrated approaches ahead of 2030 might be sustained to avoid these outcomes. We have not identified technological barriers that would prevent this.

APPENDIX A: OFFSHORE WIND CAPACITY (2025–2050)

The offshore wind capacity forecasted for the LW scenario in the FES 2020 report is given in Table A–1.

Table A–1 Offshore wind capacity forecasted in 2025-2050 per regional zone.

	Offshore Wind Capacity [MW]				
Flop Zone	**Year 2025**	**Growth →**	**Year 2030**	**Growth →**	**Year 2050**
North Scotland					
T2	1,075	+2,250	3,325	+1,500	4,825
T5	0	+1,750	1,750	+10,000	11,750
T6	1,388		1,388		1,388
Total	2,463	+4,000	6,463	+11,500	17,963
East Scotland					
T4	1,075		1,075		1,075
S6	1,746	+2,300	4,046	+4,200	8,246
Total	2,821	+2,300	5,121	+4,200	9,321
Dogger Bank					
P8	2,827	+2,603	5,427		5,427
Q2	1,700	+500	2,200	+3,200	5,400
Total	4,527	+3,103	7,627	+3,200	10,827
Eastern Regions					
J1	821	+565	1,386	+1,800	3,186
J2	848	+1,720	2,568	+348	2,916
J3	2,965	+5,069	8,034	+4,319	12,353
J5	2,044		2,044		2,044
K4	900		900		900
P7	2,520		2,520	+3,600	6,120
Total	10,098	+7,354	17,452	+10,067	27,519
South East					
B1	400		400	+400	800
C3	630		630		630
C7	300	+340	640		640
Total	1,330	+340	1,670	+400	2,070
North Wales and Irish Sea					
M6	828	+1,000	1,828	+1,580	3,408
M8	0		0	+5,400	5,400
N3	0		0	+4,800	4,800
Q8	178		178		178
R4	182		182		182
R5	1,464		1,464		1,464
Total	2,652	+1,000	3,652	+11,780	15,432
Great Britain					
Total Combined	23,891	+18,097	41,988	+41,147	83,132

APPENDIX B: TRANSMISSION LINE LOADING (2050)

The transmission lines per regional zone for which the simulations lead to loading levels above 70% (i.e. higher risk of overloading during onshore contingencies) are indicated in Table B–1.

It can be observed that the Integrated (Start 2030) design leads to comparable results to the Integrated (Start 2025) design. Furthermore, the areas in which the NOA 2020 report indicates potential future reinforcements can be found in the Holistic Offshore Transmission Planning report.

Table B–1 Simulation results: transmission line loading for the year 2050.

	Transmission Line Loading Year 2050 [%]				
	Counterfactual	Integrated (Start 2030)		Integrated (Start 2025)	
North Scotland					
Spittal–Dounreay	235	3	-232%	9	-226%
Shin–Dingwall	383	60	-323%	42	-341%
Fyrish–Beauly	375	48	-327%	31	-344%
Beauly–Fort Augustus	106	47	-59%	45	-61%
Melgarve–Bonnybridge	144	80	-64%	67	-77%
Tummel–Bonnybridge	95	52	-43%	47	-48%
Blackhillock–Kintore	103	24	-79%	5	-98%
Kintore–Tealing	111	88	-23%	94	-17%
Tealing–Kincardine	98	75	-23%	75	-23%
Fetteresso–Kincardine	105	84	-21%	80	-25%
East Scotland					
Bonnybridge–Denny	160	87	-73%	72	-88%
Denny–Lambhill	86	65	-21%	62	-24%
Clyde's Mill–Strathaven	130	89	-41%	80	-50%
Strathaven–Wishaw	100	66	-34%	54	-46%
Strathaven–Coalburn	131	70	-61%	56	-75%
Coalburn–Elvanfoot	157	97	-60%	83	-74%
Elvanfoot–Moffat	171	108	-63%	93	-78%
Elvanfoot–Gretna	177	113	-64%	99	-78%
Moffat–Harker	191	128	-63%	113	-78%
Gretna–Harker	181	119	-62%	105	-76%
Tealing–Westfield	125	96	-29%	99	-26%
Westfield–Longannet	96	66	-30%	73	-23%
Kincardine–Currie	119	67	-52%	84	-35%
Currie–Kaimes	86	50	-36%	53	-33%
Kaimes–Smeaton	95	51	-44%	51	-44%
Cockenzie–Eccles	143	57	-86%	56	-87%
Eccles–Stella West	120	50	-70%	44	-76%

	Transmission Line Loading Year 2050 [%]				
	Counterfactual	**Integrated (Start 2030)**		**Integrated (Start 2025)**	
Dogger Bank					
Harker–Hutton	146	103	-43%	89	-57%
Stella West–Spennymoor	99	58	-41%	68	-31%
Spennymoor–Norton	93	53	-40%	62	-31%
Norton–Osbaldwick	168	130	-38%	114	-54%
Lackenby–Thornton	105	78	-27%	79	-26%
Drax–Keadby	127	75	-52%	101	-26%
Keadby–West Burton	143	110	-33%	96	-47%
Keadby–Cottam	138	77	-61%	68	-70%
West Burton–Cottam	125	73	-52%	78	-47%
Eastern Regions					
West Burton–High Marnham	113	106	-7%	102	-11%
High Marnham–Stoke Bardolph	143	121	-22%	118	-25%
Stoke Bardolph–Ratcliffe on Soar	134	112	-22%	109	-25%
Enderby–East Claydon	94	45	-49%	44	-50%
Cottam–Staythorpe	100	137	+37%	127	+27%
Staythorpe– Ratcliffe on Soar	92	109	+17%	109	+17%
Cottam–Grendon	113	97	-16%	94	-19%
Grendon–Sundon	107	80	-27%	77	-30%
Walpole–Burwell Main	105	70	-35%	72	-33%
Burwell Main–Pelham	101	65	-36%	68	-33%
Norwich Main–Bramford	84	39	-45%	15	-69%
South East					
Sundon–East Claydon	103	93	-10%	93	-10%
Sundon–Cowley	104	80	-24%	80	-24%
East Claydon–Cowley	127	86	-41%	86	-41%
Cowley–Didcot	93	66	-27%	66	-27%
Didcot–Bramley	112	80	-32%	80	-32%
Iver–West Weybridge	105	55	-50%	54	-51%
Sundon–Elstree	151	80	-71%	77	-74%
Elstree–St John's Wood	141	66	-75%	63	-78%
Bramford–Bulls Lodge	155	77	-78%	73	-82%
Bramford–Rayleigh Main	118	57	-61%	54	-64%
Rayleigh Main–Coryton South	100	44	-56%	41	-59%
Rayleigh Main–Tilbury	129	48	-81%	44	-85%
Coryton South–Tilbury	127	32	-95%	29	-98%
Tilbury–Kingsnorth	102	39	-63%	33	-69%
Kingsnorth-Grain	19	68	+49%	73	+54%

	Transmission Line Loading Year 2050 [%]				
	Counterfactual	**Integrated (Start 2030)**		**Integrated (Start 2025)**	
North Wales and Irish Sea					
Penwortham–Carrington	87	77	-10%	105	+18%
Birkenhead–Lister Drive	134	34	-100%	62	-72%
Pentir–Trawsfynydd	159	51	-108%	13	-146%
Bodelwyddan–Connah's Quay	86	20	-66%	8	-78%
Connah's Quay–Legacy	104	63	-41%	69	-35%
Legacy–Ironbridge	142	69	-73%	64	-78%
Ironbridge–Feckenham	163	75	-88%	72	-91%
Daines–Drakelow	135	82	-53%	86	-49%
Drakelow–Feckenham	118	77	-41%	78	-40%
Feckenham–Minety	161	81	-80%	79	-82%
Whitson–Seabank	43	100	+57%	100	+57%