CMP213 Impact Assessment Modelling Report

This report describes the impact assessment modelling undertaken by National Grid to provide a robust evidence base for the Original and potential alternatives raised under CMP213.

Version	Date
2.1	25th July 2013

Contents

About this document

This report describes the impact assessment modelling undertaken by National Grid to provide a robust evidence base for the Original and potential alternatives raised under CMP213 (Project TransmiT TNUoS Developments).

The document has been produced solely to inform Ofgem's impact assessment for CMP213, and has not been circulated more widely. The information presented in the report has previously been made available to industry as part of National Grid's response to the CMP213 Code Administrator consultation, with the report only discussing these results in further detail.

Document Control

Version	Date	Author	Change Reference
1.0	24th May 2013	National Grid	Final Version
2.0	12th July 2013	National Grid	Inclusion of analysis of diversity options with 50% HVDC converter costs, and analysis of results from revised diversity 3 calculation
2.1	25th July 2013	National Grid	Updates for external publication alongside Ofgem Impact Assessment Documentation.

1 Background

1.1 As part of the transmission charging Significant Code Review under Project TransmiT, a range of potential charging options were considered and assessed to understand which would best further the objectives of achieving sustainability targets, ensuring security of supply and providing best value for money for current and future consumers. Redpoint Energy were commissioned by Ofgem to provide a quantitative assessment of how the different charging options might impact on these objectives. That assessment was completed using a suite of models developed by Redpoint Energy with assistance from National Grid. Redpoint Energy provided a report of the results of this assessment, along with the methodology and assumptions made in December 2011[1].

1.2 The Direction issued by the Authority to National Grid in relation to the Significant Code Review under Project TransmiT required National Grid to ensure that any Modification proposals developed were supported by a robust evidence base.[2] In order to ensure a robust evidence base for the CMP213 Modification proposal National Grid employed the same Redpoint models previously developed as part of the transmission charging Significant Code Review under Project TransmiT, and utilised them for the quantitative assessment of CMP213. The functionality and approach to the analysis remained unchanged from that developed by Redpoint for this earlier analysis and is described in full in their report of December 2011.[3] In order to ensure the information and assumptions used within the model remained current, the CMP213 Workgroup established a modelling sub-group to review this area of work. As a result, National Grid, through this discussion with the modelling subgroup, reviewed the Redpoint model and updated several data sources to better reflect the current background assumptions.

1.3 The CMP213 Workgroup agreed that the impact assessment should be carried out on six models representative of potential future scenarios. These models are set out in Table 1.1 below, and the Workgroup believed they provided sufficient representation to allow their assessment to provide a robust evidence base.

[1] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

[2] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20direction%2025%20May%202012.pdf

[3] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

Model	Sharing Assumptions	Islands / HVDC Assumptions
Status Quo	None	100% of converter costs included
Original	Original	100% of converter costs included
Diversity 1	Diversity 1	100% of converter costs included
Diversity 2	Diversity 2	100% of converter costs included
Diversity 3	Diversity 3	100% of converter costs included
HVDC – 50%	Original	50% of converter costs included

Table 1.1 -Table of models initially assessed

1.4 In line with the work previously carried out by Redpoint, two stages of analysis were undertaken. A first stage with fixed Contract for Difference (CFD) strike prices, and a second where CFD strike prices were altered to ensure three conditions were met;

- EU renewable share at 2020 of 30%
- Carbon emissions in 2030 at 100g/kWhr
- Nuclear capacity at 2030 of 14GW

The stage 2 approach is detailed further in section 2 of this report.

1.5 The Workgroup requested stage 2 results ahead of the determination and voting on the WACMs, as there was general agreement that this assessment would provide an evidence base to better inform the voting decisions of Workgroup members against the Applicable CUSC Objectives. Initial modelling results were presented to the CMP213 workgroup in March 2013. It was recognised that there were further improvements that could be made to the model to further refine results, and National Grid agreed to undertake these changes and provide revised results as part of their response to the CMP213 Code Administrator Consultation. These changes were;

- Improved capacity mechanism (EMR modelling)
- TEC change updates
- Presentational changes such that charts and tables start in 2014/15

1.6 Additionally National Grid agreed to review and resolve the driver behind tariff spikes observed in all modelled alternatives in later years. This was resolved.

1.7 Revised results were provided in the National Grid response to the CMP213 Code Administrator consultation[4], and discussed further with stakeholders at the Transmission Charging Methodologies Forum in May 2013[5].

1.8 In May 2013, as part of their assessment of CMP213, Ofgem requested National Grid to undertake further impact assessment modelling such that the models outlined in table 1.2 were included in the analysis.

[4] http://www.nationalgrid.com/NR/rdonlyres/D78E4616-9048-4830-9622-ECE42539961A/60495/Volume3v10.pdf

[5] http://www.nationalgrid.com/NR/rdonlyres/4CFFA983-DE11-434F-9A12-76324D6CE19E/60596/TCMFslidepack21stMay.pdf

Model	Sharing Assumptions	Islands / HVDC Assumptions
Diversity 1 - 50% HVDC	Diversity 1	50% of converter costs included
Diversity 2 - 50% HVDC	Diversity 2	50% of converter costs included
Diversity 3 - 50% HVDC	Diversity 3	50% of converter costs included

Table 1.2 - Table of further models assessed

2 Introduction

Report Structure

2.1 This report describes the revised stage 2 CMP213 Impact Assessment results produced in April 2013 and the results of the additional stage 2 analysis produced in May 2013 by National Grid. Details of the stage 2 approach are provided below.

2.2 The report is laid out in sections as described in Figure 2.1 below. In all cases the five modelled options are primarily compared against the status quo model to understand the differences in results.

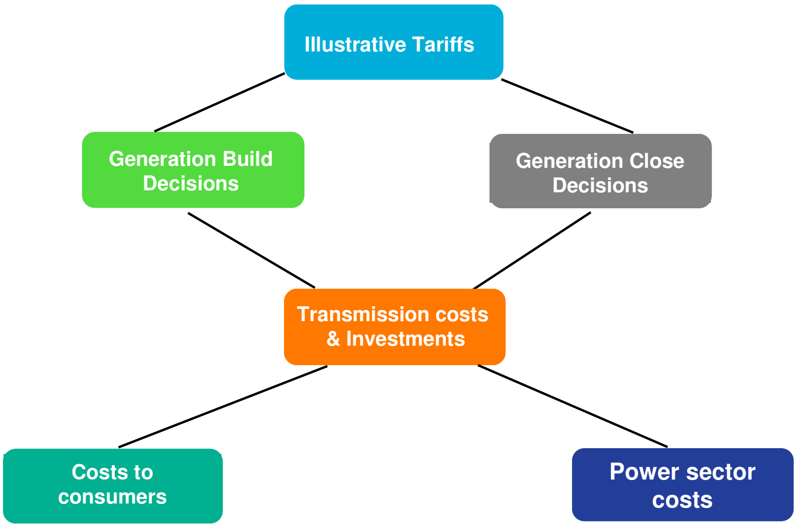


Figure 2.1 – Structure of report

2.3 The first part of the report looks at the effect on both generation and demand tariffs of each of the modelled options.

2.4 Cognisant of the differences in tariffs, the report then considers the impacts on generation build and closure decisions.

2.5 These generation investment decisions impact on transmission costs and investments which are covered in the next section.

2.6 Finally the impact of all these changes on the two primary sets of outputs, cost to consumers and power sector costs, is considered.

The stage 2 approach

2.7 In order to allow for meaningful comparisons of costs across different scenarios, the model runs have been set to meet sustainability targets of 30% renewable generation in 2020 and carbon intensity of 100g/kWh in 2030. The CfD strike prices are set individually for each model run in such a way that they each met the sustainability goals. Within these goals, there will be variation in the timing and mixture of low carbon investment across the model runs.

2.8 The resulting renewables generation and carbon intensity are shown in Figures 2.2 and 2.3 respectively.

2.9 The underling generation capacity differences responsible for the variation in these results are discussed in section 4. It is notable that although all the runs are quite closely aligned, the Status Quo run has the highest level of renewable generation throughout the modelling period, with Diversity 1 having the lowest. It is also worth noting that where the same sharing option has been modelled with 50% and 100% converter costs included in the HVDC expansion factor calculation, there is very little difference between the resulting renewable share.

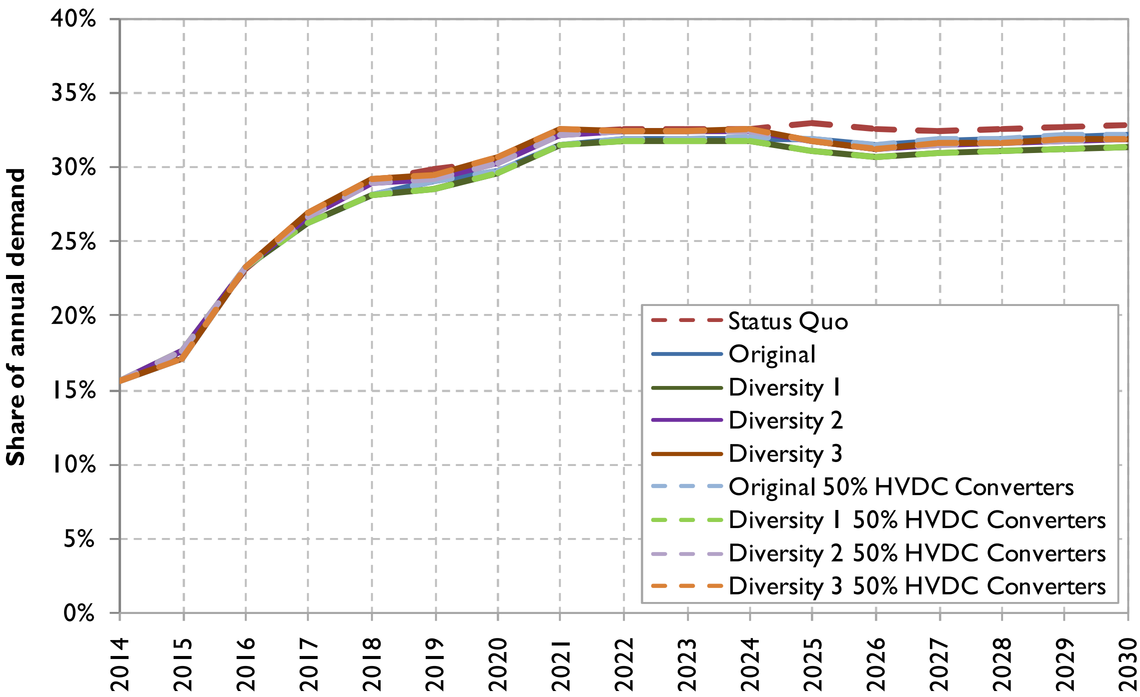


Figure 2.2 - Renewable generation

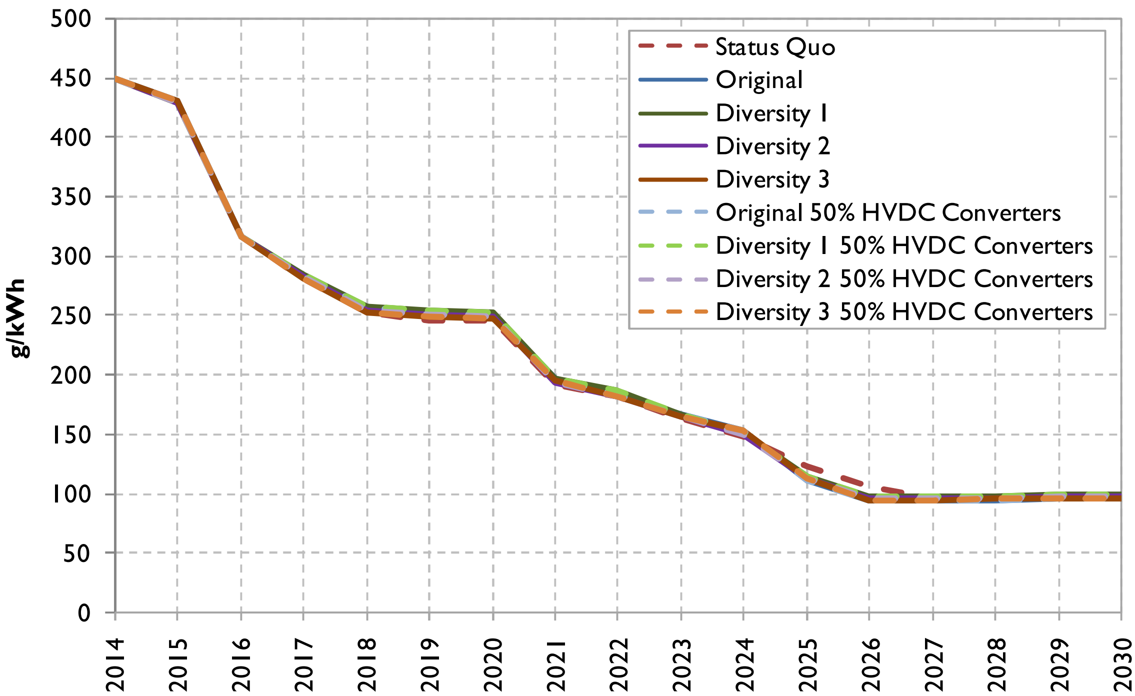


Figure 2.3 - Carbon Intensity

3 Illustrative Tariffs

Tariff changes across modelled time period

3.1 In the modelling undertaken the main changes in each transport model that will affect tariffs relate to either changes in the generation background (i.e. the effect on modelled flows resulting from new generation connections or retirements), or significant reinforcements (e.g. HVDC links). In addition to these, changes in the total level of revenue collected (particularly due to the introduction of new offshore transmission networks) will also have an effect on tariffs, with this being more noticeable on zonal demand tariffs (as for generation tariffs a large proportion of offshore revenues are collected via local charges). The following sections discuss the drivers behind major year on year changes in each of the 9 models.

Status Quo

3.2 The following charts depict the zonal tariffs resulting from the modelled Status Quo scenario.

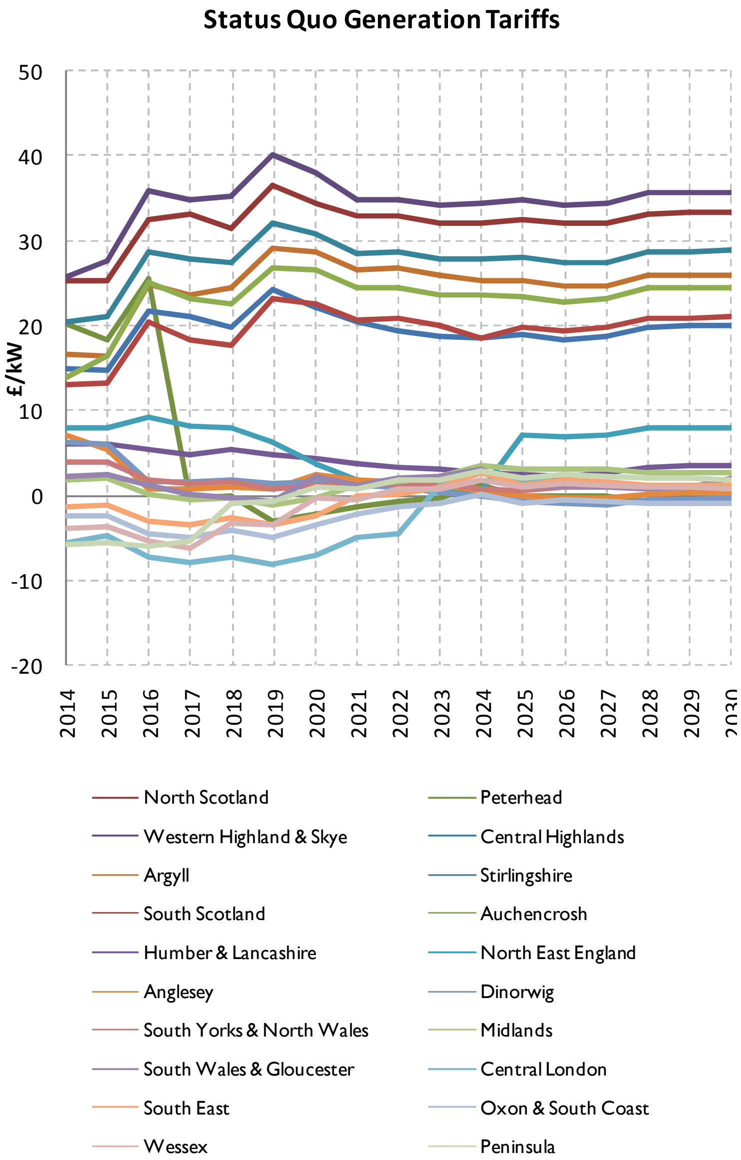


Figure 3.1

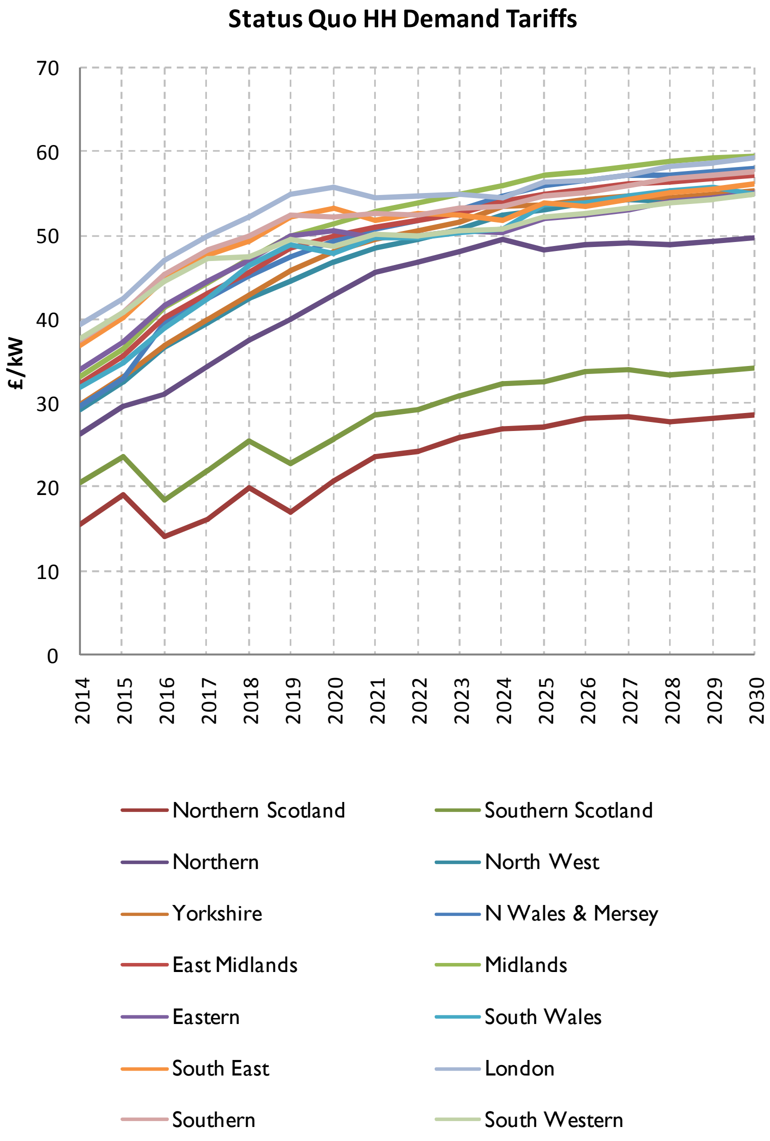


Figure 3.2

3.3 Note that the tariff for zone 2, does not apply to any generation from 2017.

3.4 The following table lists the major year on year tariff changes, with the exception of year on year changes in demand tariffs driven by allowed revenue changes* which are covered below.

Year	Zones affected	Change	Tariff	Driver
2016	G1-8	+£7-8/kW	Generation	Commissioning of Western HVDC link
2016	G11-20	-£1-5/kW	Generation	
2016	D1&2	-£8-9/kW	HH Demand	
2016	D4-14	+£0.5-3/kW	HH Demand	
2016	D1-14	+~£3.5/kW	HH Demand	Increase in allowed revenue*
2017	G1-20	-£0.4/kW	Generation	Decrease in generation residual, due to >27% of additional offshore MAR being collected through local charges.
2017	G1	+£1/kW	Generation	500MW additional wind generation connecting in Northern Scotland.
2017	G15	-£0.7/kW	Generation	Closure of 1.6GW of generation connecting in South Wales.
2017	G20	+£1/kW	Generation	Additional offshore capacity connecting in zone 20
2017	G3-8 & G10	-0.4-1.50/kW	Generation	4GW of TEC reductions from Northern based generation, and introduction of 1.5GW additional offshore and 760MW of CCGT in more Southerly zones.
2018	G1&6	-£1/kW	Generation	Connection of 400MW of offshore wind in zone 5.
2018	G5	+£0.8/kW	Generation	
2019	G1 & G3-8	+£3.8-5/kW	Generation	Commissioning of Eastern HVDC link
2019	G9-20	-£0.2-1.6/kW	Generation	
2019	D1&2	-£4.50-5/kW	HH Demand	
2019	D1-14	+~£2.5/kW	HH Demand	Increase in allowed revenue*
2020	G1 & G3-10	-£0.3-2/kW	Generation	3.3 GW of TEC reductions from Northern generation, and commissioning of 1.7GW of Nuclear generation in the South of England and an additional Irish interconnector (1GW).
2020	G11-20	+£0.1-3.3/kW	Generation	
2021	G1, G3-12 & G15	-£0.5-3.3/kW	Generation	2.3 GW of TEC reductions from Northern based generation, and commissioning of 1.7GW of Nuclear and 5.5GW of CCGT generation across the South East.
2021	G14 &	+£1.3-	Generation	

* Where changes due to allowed revenue changes are included above, this is to provide an indication of the effect of each individual event that changes tariffs within a year.

Year	Zones affected	Change	Tariff	Driver
	G16-18	2.3/kW		
2025	G10	+£6.4/kW	Generation	Commissioning of Norwegian Interconnector (Blyth).
2025	G15	-£2/kW	Generation	Commissioning of Northern and South Eastern based generation.

Table 3.1 – Drivers for changes in status quo tariffs

3.5 Further to the above, the main driver behind year on year demand tariff changes relate to changes in the allowed TO revenues, and are shown in Figure 3.3. It can be noted that aside from the effect of HVDC links being commissioned, the year on year tariff trends roughly align with the changes in the TO revenue allowance.

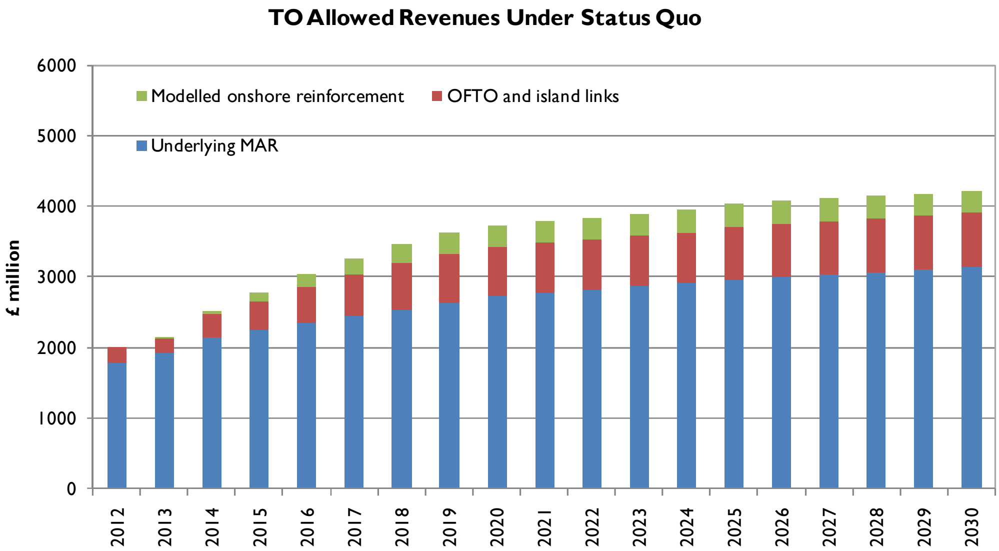


Figure 3.3 – TO Allowed Revenues under Status Quo

Original model (50% and 100% HVDC options)

3.6 The following charts depict tariffs resulting from both the Original modification, and the original with modified treatment of HVDC converter costs within the expansion factor calculation such that only 50% of these are included. These charts show the effect on 30% load factor intermittent and 70% conventional generation.

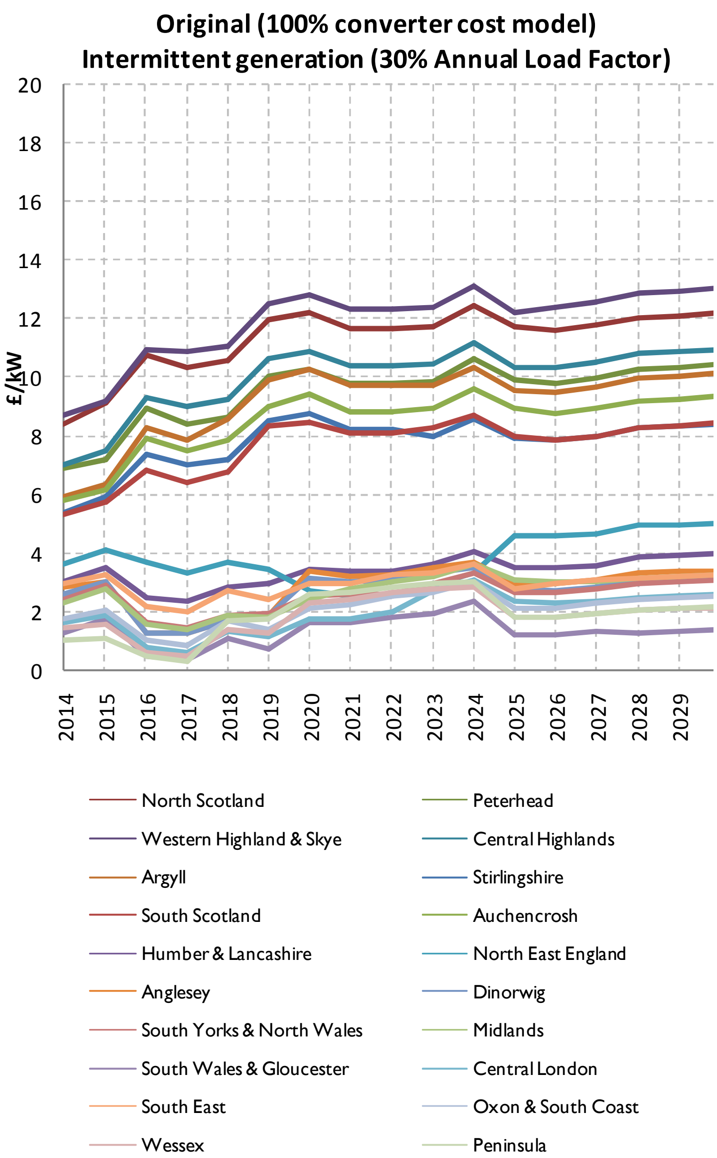


Figure 3.4

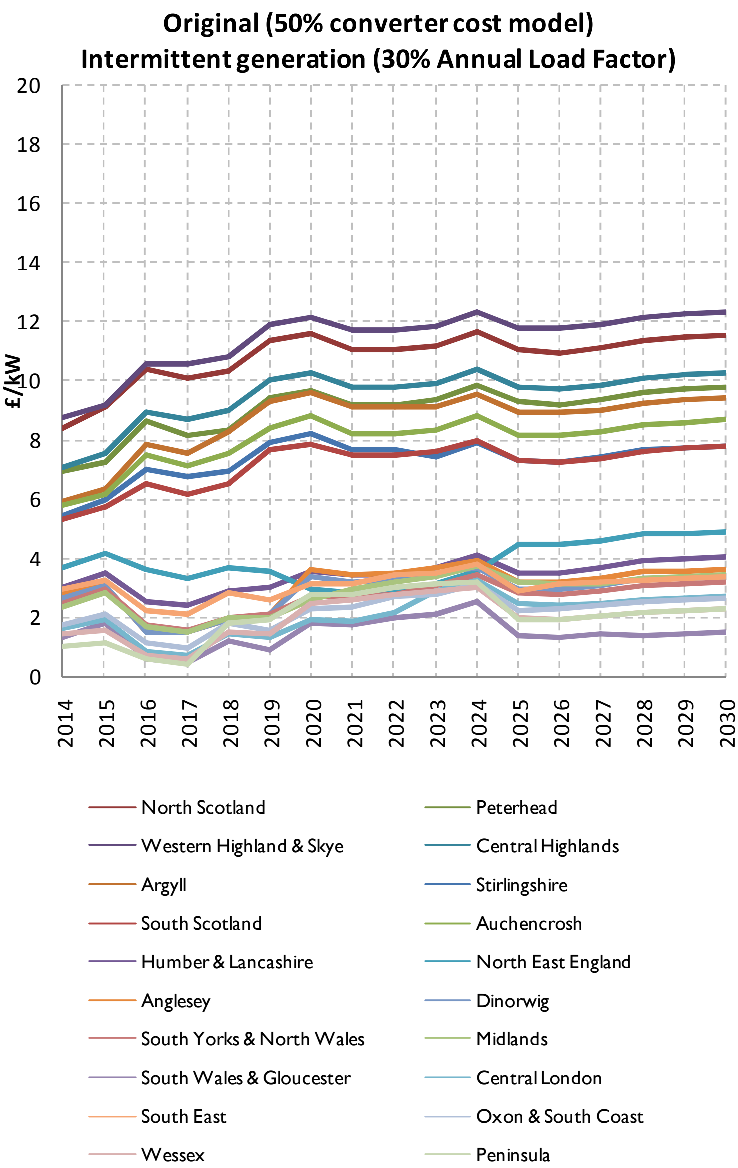


Figure 3.5

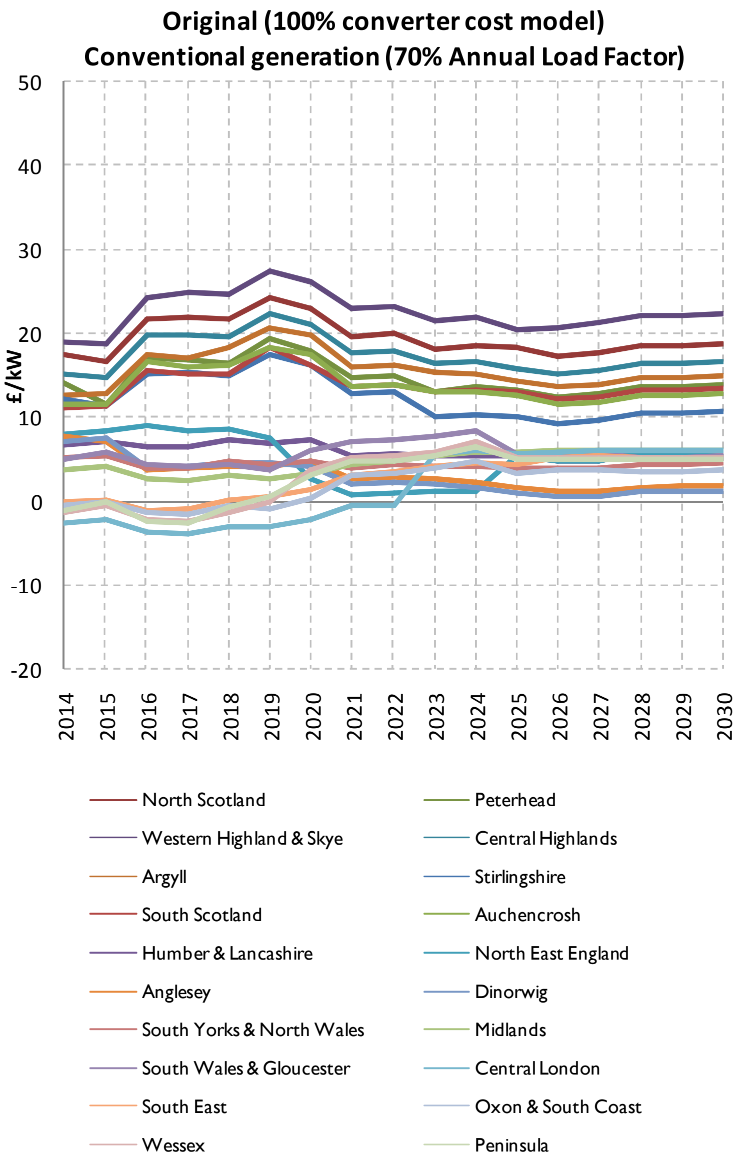


Figure 3.6

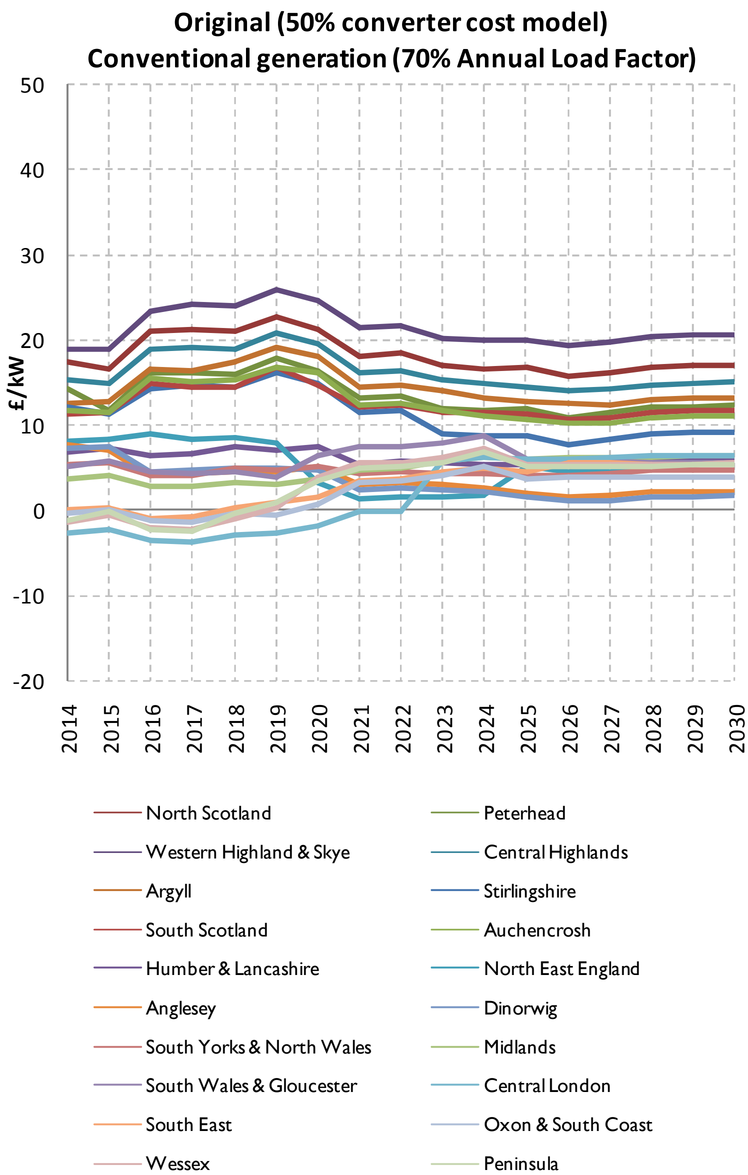


Figure 3.7

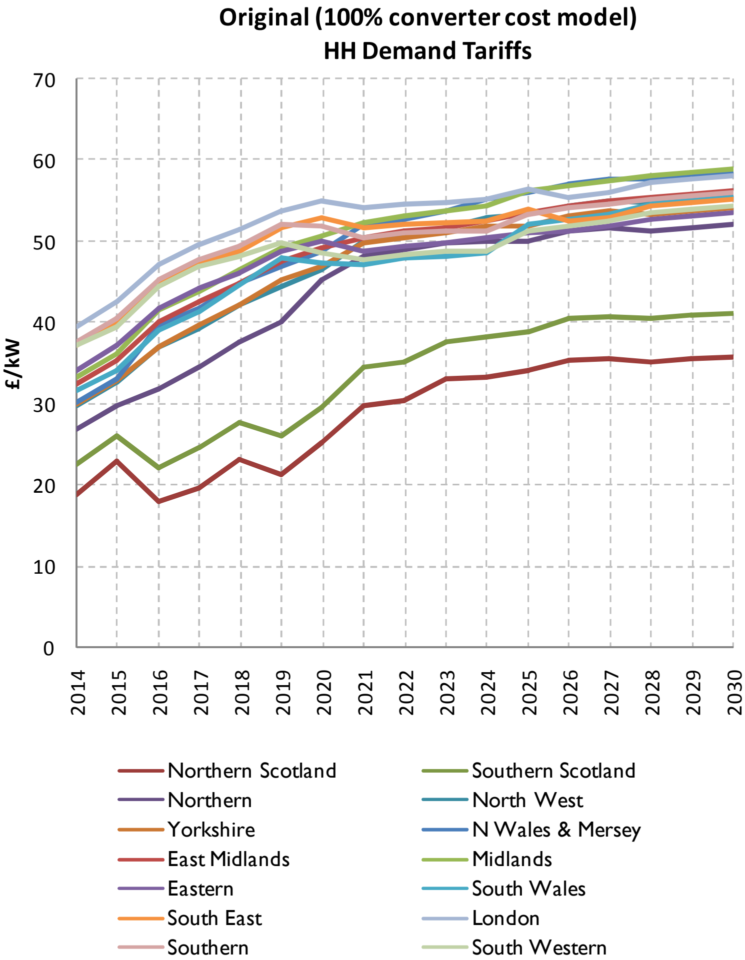


Figure 3.8

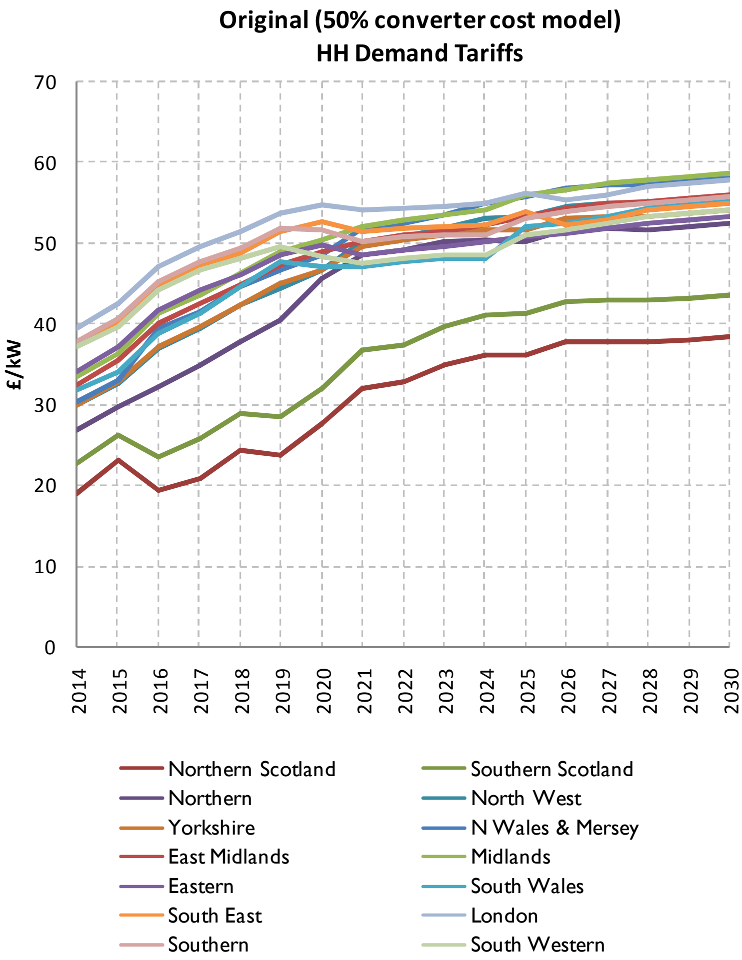


Figure 3.9

3.7 When comparing each set of charts, it is clear that the general shape of the trend in each tariff is very similar across the two options for treatment of HVDC converter cost under this model. The main difference is that the effect that commissioning of HVDC links has on tariffs under the 50% cost inclusion option is less than that in the 100% option. The following table lists the major year on year tariff changes, with the exception of year on year changes in demand tariffs* which follow a similar trend to the allowed revenue, as discussed for the Status Quo model.

* Where changes due to allowed revenue changes are included above, this is to provide an indication of the effect of each individual event that changes tariffs within a year.

Year	Zones affected	Change (100% model)	Change (50% model)	Tariff	Driver
2016	G1-8	+£1.1-1.9/kW	+£0.8-1.5/kW	30% Int. Gen	Commissioning of Western HVDC link
2016	G9-20	-£0.5-1.8/kW	-£0.5-1.6/kW	30% Int. Gen	
2016	G1-8	+£3.8-5.5/kW	+£2.9-4.6/kW	70% Con. Gen	
2016	G11-20	-£1.3-3.4/kW	-£1.1-3.0/kW	70% Con. Gen	
2016	D1-3	-£1.9-8.0/kW	-£1.5-6.6/kW	HH Demand	
2016	D4-14	+£0.3-2.8/kW	+£0.2-2.4/kW	HH Demand	
2016	D1	-£1.2/kW	-£1.2/kW	HH Demand	Generation background changes (e.g. retirement of predominantly Southern based LCPD opt out plant))
2016	D1-14	+~£3.9/kW	+~£3.9/kW	HH Demand	Increase in allowed revenue*
2018	G5	+£0.8/kW	+£0.8/kW	30% Int. Gen	Connection of 400MW of offshore wind in zone 5.
2018	G5	+£1.2/kW	+£1.2/kW	70% Con. Gen	
2018	G15-20	+£0.7-1.4/kW	+£0.7-1.4/kW	30% Int. Gen	Connection of Southern based capacity (e.g. Offshore wind (+600MW), South Eastern CCGT (+800MW), additional French interconnector (1000MW))
2018	G15-20	+£0.8-2.0/kW	+£0.8-2.0/kW	70% Con. Gen	
2019	G1-8	+£1.2-1.6/kW	+£0.9-1.2/kW	30% Int. Gen	Commissioning of Eastern HVDC link
2019	G1-8	+£2.2-3.1/kW	+£1.5-2.2/kW	70% Con. Gen	
2019	D1-2	-£4.2-4.5/kW	-£3.0-3.1./kW	HH Demand	
2019	D14	-£1.2/kW	-£1.2/kW	HH Demand	Connection of Southern based generation (e.g. 800MW CCGT in Wessex)
2019	G19-20	+£1.2-1.3/kW	-£1.3-1.4/kW	70% Con. Gen	
2019	D1-14	+~£2.3/kW	+~£2.3/kW	HH	Increase in allowed revenue*

Year	Zones affected	Change (100% model)	Change (50% model)	Tariff	Driver
				Demand	
2020	G1-8 & G10	-£0.8-4.9/kW	-£0.8-4.6/kW	70% Con. Gen	3.3 GW of TEC reductions from Northern generation, and commissioning of 1.7GW of Nuclear generation in the South of England and an additional Irish interconnector (1GW).
2020	G11 & G13-20	+£0.7-3.7/kW	+£0.7-3.7/kW	70% Con. Gen	
2020	G11 & 12	+£1.3-1.5/kW	+£1.3-1.5/kW	30% Int. Gen	Commissioning of additional Irish interconnector (1GW)
2021	G1-8	-£0.4-0.6/kW	-£0.4-0.6/kW	30% Int. Gen	Approximately 1GW of TEC reductions from Northern generation, and commissioning of 1.7GW of Nuclear and 5.6GW of CCGT generation across the South. Also has decreasing effect on Southern Demand tariffs.
2021	G1-13	-£0.8-3.8/kW	-£0.8-3.8/kW	70% Con. Gen	
2021	G14-20	+£1.0-2.7/kW	+£1.0-2.7/kW	70% Con. Gen	
2025	G10	+£1.2/kW	+£0.9/kW	30% Int. Gen	Commissioning of Norwegian Interconnector (Blyth).
2025	G10	+£4.2/kW	+£3.4/kW	70% Con. Gen	Commissioning of Norwegian Interconnector (Blyth).
2025	G1-9 & G11-20	-£0.5-1.2/kW	-£0.5-1.2/kW	30% Int. Gen	Combined effect of commissioning of 9GW of generation, including 6.2GW of CCGT with CCS (mainly Midlands & Northern England based), 900MW of Scottish Offshore wind, and 1.7GW of South Eastern based Nuclear generation.
2025	G3-5, G15 & G18-20	-£0.9-2.8/kW	Zone G3: +£0.1/kW Other Zones: -£0.2-2.8/kW	70% Con. Gen	Combined effect of commissioning of 9GW of generation, including 6.2GW of CCGT with CCS (mainly Midlands & Northern England based), 900MW of Scottish Offshore wind, and 1.7GW of South Eastern based Nuclear generation.

Table 3.2 – Drivers for changes in original (100% HVDC & 50% HVDC) tariffs

Diversity 1 (50% and 100% HVDC options)

3.8 The following charts depict tariffs resulting from Diversity option 1 with inclusion of 100% and 50% HVDC converter costs within the expansion factor calculation. These charts show the effect on 30% load factor intermittent and 70% conventional generation.

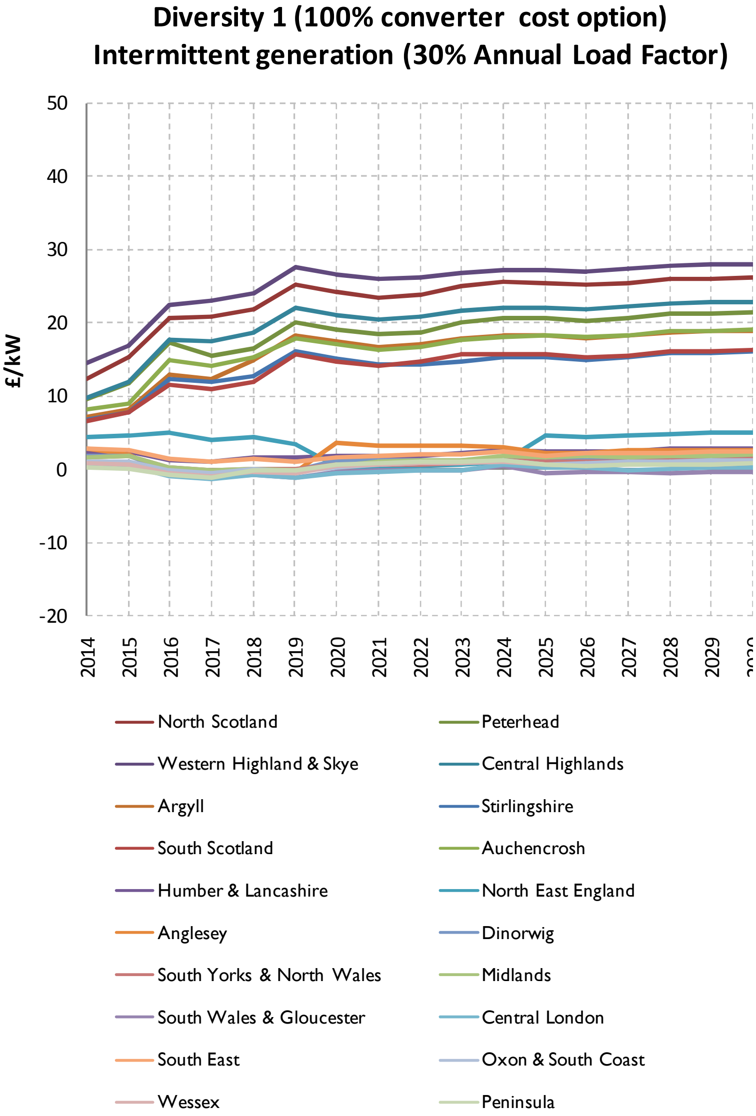


Figure 3.10

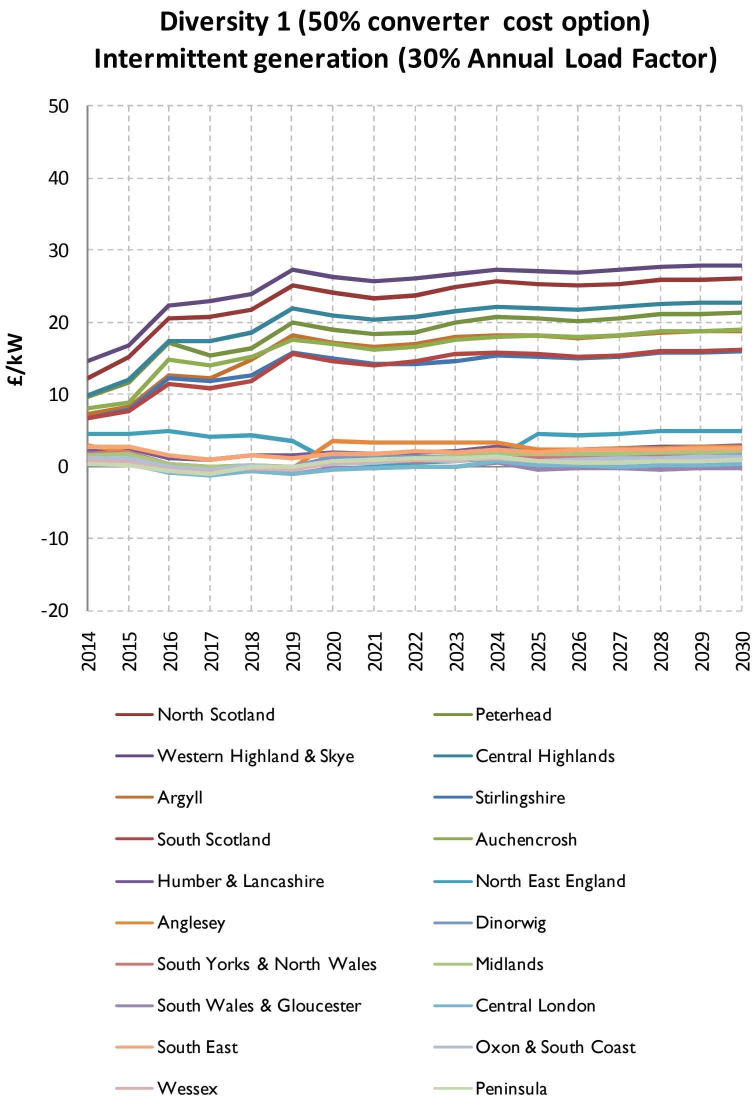


Figure 3.11

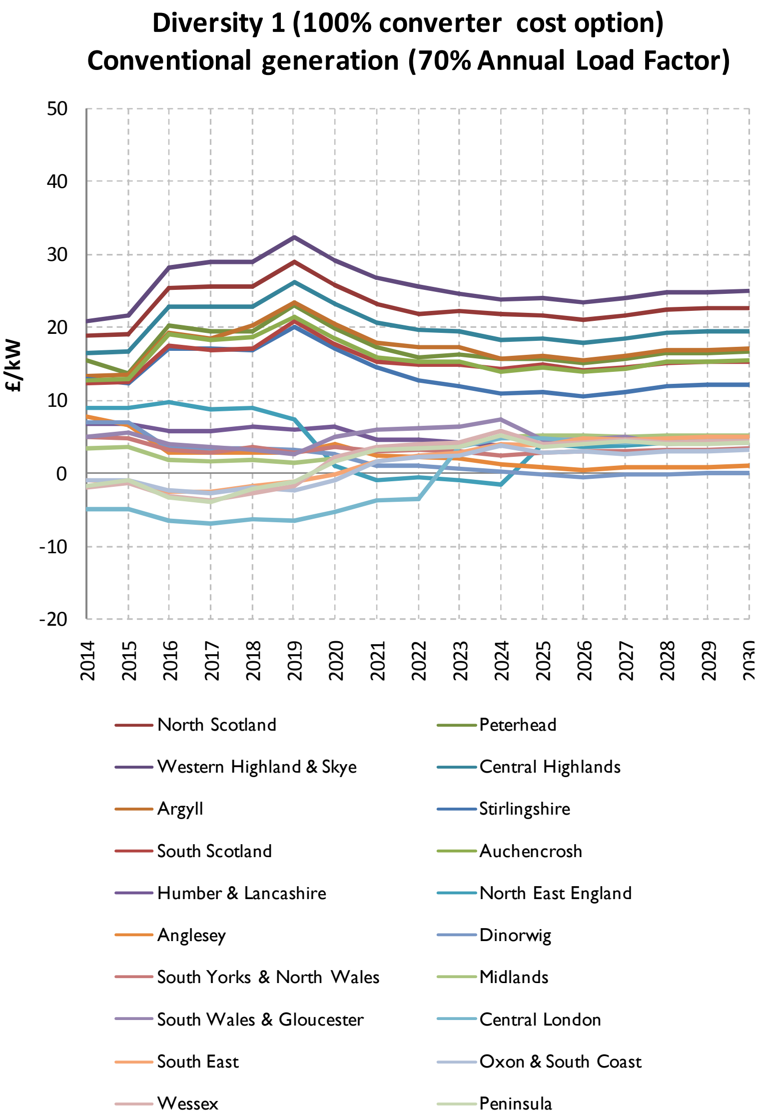
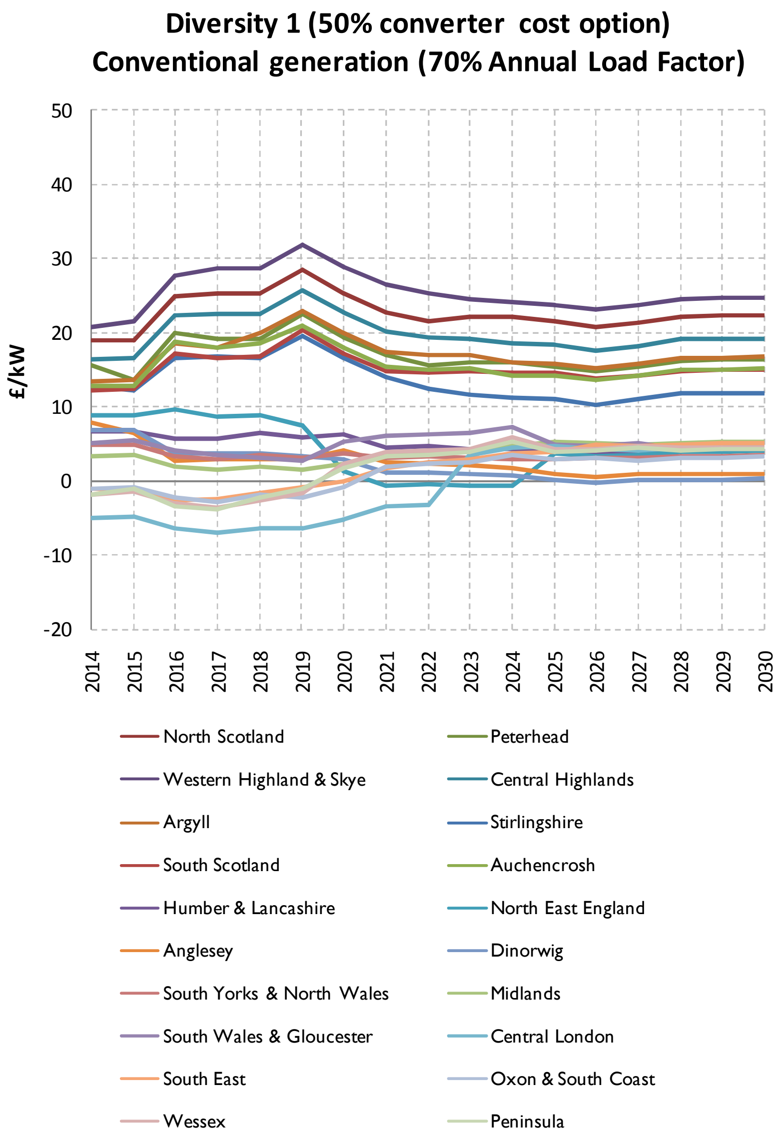


Figure 3.12



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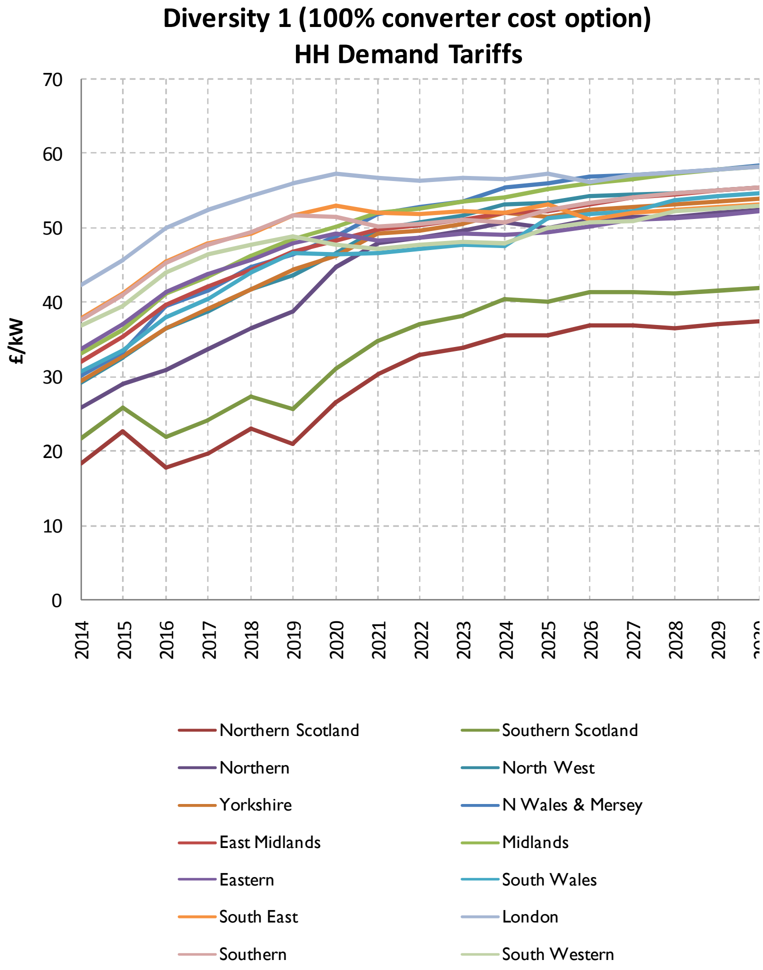

Figure 3.14

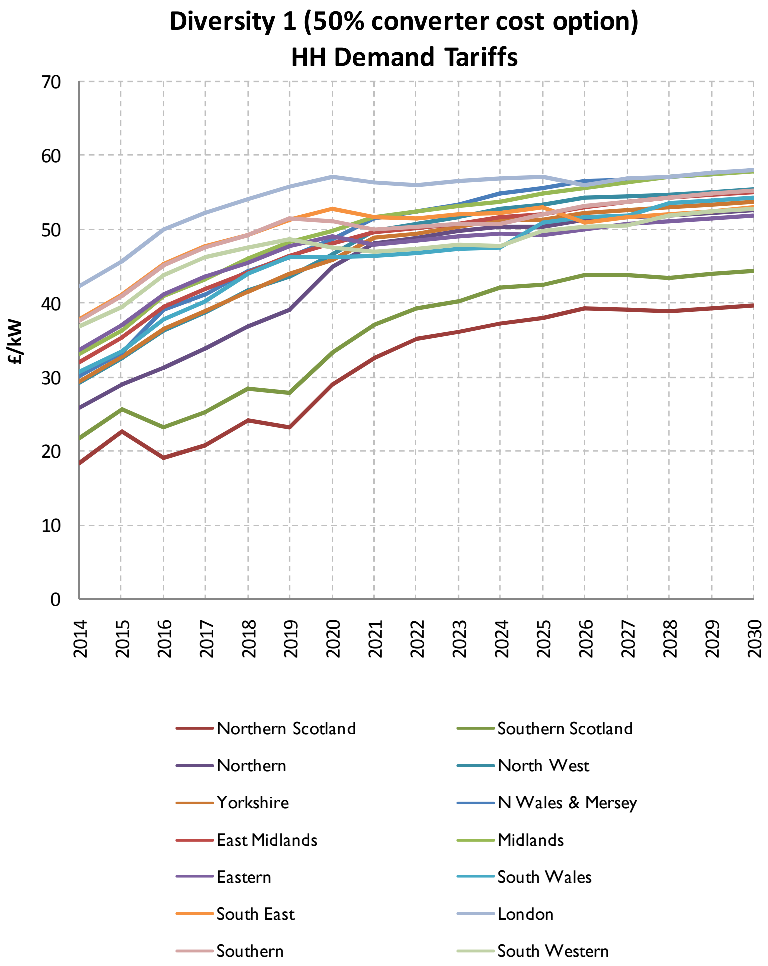

Figure 3.15

3.9 When comparing each set of charts, it is clear that the general shape of the trend in each tariff is similar across these two options. Again, the main difference is that the effect that commissioning of HVDC links has on tariffs under the 50% cost inclusion option is less than that in the 100% option. When comparing to the charts for the Original modification with the two different treatments of HVDC converter costs, the shape is similar for demand and 70% load factor conventional generation, but the range of resulting tariffs is much greater under the diversity options. The following tables list the major year on year tariff changes, with the exception of year on year changes in demand tariffs[*] which follow a similar trend to the allowed revenue, as discussed for the Status Quo model.

[*] Where changes due to allowed revenue changes are included above, this is to provide an indication of the effect of each individual event that changes tariffs within a year.

Year	Zones affected	Change (100% Converter Cost Model)	Change (50% Converter Cost Model)	Tariff	Driver
2016	G1-8	+£3.9-6.0/kW	+£3.7-5.8/kW	30% Int. Gen	Commissioning of Western HVDC link
2016	G9 & G11-20	-£0.8-2.9/kW	-£0.8-2.8/kW	30% Int. Gen	
2016	G1-8	+£4.7-6.6/kW	+£4.3-6.2/kW	70% Con. Gen	
2016	G9 & G11-20	-£0.9-3.9/kW	-£0.9-3.8/kW	70% Con. Gen	
2016	D1-2	-£3.8-4.1/kW	-£2.6-3.6/kW	HH Demand	
2016	D3-14	+£1.7-6.1/kW	+£2.1-5.8/kW	HH Demand	
2017	G1-20	-£0.4/kW	-£0.4/kW	30% Int. Gen & 70% Con. Gen	Decrease in generation residual, due to >27% of additional offshore MAR being collected through local charges.
2017	G1 & G3	+£0.5-1.0/kW	+£0.5-1.0/kW	30% Int. Gen	2GW additional wind generation connecting in Scotland.
2017	G5, G7-8 & G10	-£0.4-1.5/kW	-£0.2-0.4/kW	30% Int. Gen	4GW of TEC reductions from Northern generation, and introduction of 800MW additional offshore and 760MW of CCGT in more Southerly zones.
2017	G5, G7-8 & G10	-0.3-0.5/kW	-£0.2-0.5/kW	70% Con. Gen	
2018	G5	+£2.6/kW	+£2.6/kW	30% Int. Gen	Connection of Offshore Wind in zone 5.
2018	G5	+£1.7/kW	+£1.8/kW	70% Con. Gen	Connection of 400MW of offshore wind in zone 5.
2018	G15-20	+£0.5-1.1kW	+£0.4-1.1kW	30% Int. Gen	Connection of 1GW of largely southern based Offshore wind and additional French interconnector
2018	G16-20	+£0.6-1.7kW	+£0.6-1.7kW	70% Con. Gen	
2019	G1-8	+£2.5-3.8/kW	+£2.4-3.7/kW	30% Int. Gen	Commissioning of Eastern HVDC link
2019	G10 & G13-19	-£0.1-0.9/kW	-£0.0-0.9/kW	30% Int. Gen	
2019	G1-8	+£2.6-3.8/kW	+£2.4-3.6/kW	70% Con. Gen	
2019	G9-16 & G18	-£0.5-1.4/kW	-£0.0-1.4/kW	70% Con. Gen	
2019	D1-2	-£3.8-4.1/kW	-£2.5-2.6/kW	HH Demand	
2019	D3, D5, D7-11 & D13	+£0.2-0.6/kW	+£0.3-0.6/kW	HH Demand	

Year	Zones affected	Change (100% Converter Cost Model)	Change (50% Converter Cost Model)	Tariff	Driver
2019	D1-14	+~£1.9/kW	+~£1.9/kW	HH Demand	Increase in allowed revenue*
2020	G1-8 & G10	-£0.7-2.9/Kw	-£0.7-2.9/Kw	30% Int. Gen	3.3GW of TEC reductions from Northern generation, and commissioning of 1.7GW of Nuclear Generation in the South of England and an additional Irish interconnector (1GW).
2020	G9 & G11-20	+£0.3-3.8/kW	+£0.3-3.8/kW	30% Int. Gen	
2020	G1-8 & G10	-£2.9-6.4/kW	-£2.9-6.2/kW	70% Con. Gen	
2020	G9 & G11-20	+£0.3-3.9/kW	+£0.4-3.9/kW	70% Con. Gen	
2021	G1-G12	-£0.1-0.8/kW	-£0.0-0.8/kW	30% Int. Gen	1.8GW of TEC reductions from Northern generation, and commissioning of 1.7GW of nuclear generation and 5.6GW of new CCGT across the South. Also has decreasing effect on Southern Demand tariffs.
2021	G1-G12	-£1.6-2.6/kW	-£1.6-2.6/kW	70% Con. Gen	
2021	G14-20	+£0.1-0.5/kW	+£0.1-0.5/kW	30% Int. Gen	
2021	G14-20	+£1.6-2.7/kW	+£0.8-2.7/kW	70% Con. Gen	
2025	G10	+£3.5/kW	+£3.2/kW	30% Int. Gen	Commissioning of Norwegian Interconnector (Blyth).
2025	G10	+£5.4/kW	+£4.4/kW	70% Con. Gen	
2025	G11-20	-£0.1-0.9/kW	-£0.1-0.9/kW	30% Int. Gen	Combined effect of commissioning of 9GW of generation, including 6.2GW of CCS plant (mainly Midlands & Northern England based), and 1.7GW of nuclear generation in the South East.
2025	G11-12, G15 & G18-20	-£0.3-2.7/kW	-£0.6-2.5/kW	70% Con. Gen	

Table 3.3 – Drivers for changes in diversity 1 tariffs

Diversity 2 (50% and 100% HVDC options)

3.10 The following charts depict tariffs resulting from Diversity option 2 with inclusion of 100% and 50% HVDC converter costs within the expansion factor calculation. These charts show the effect on 30% load factor intermittent and 70% conventional generation.

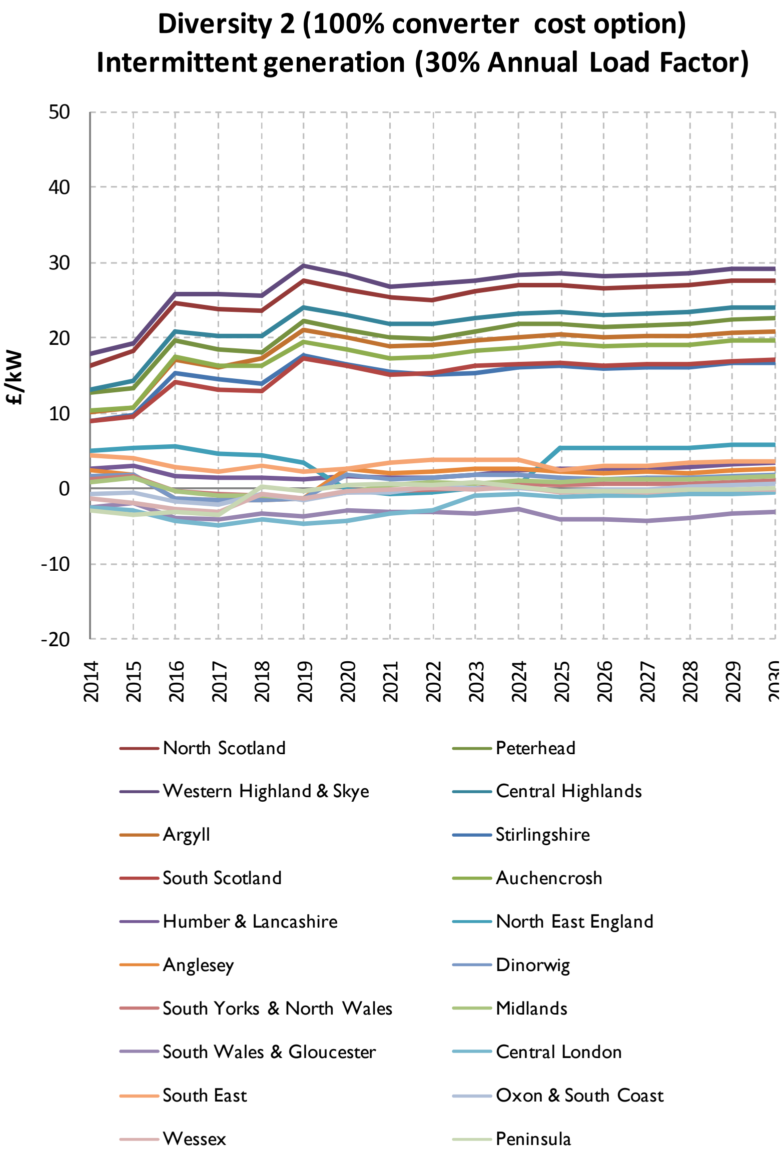

Figure 3.16

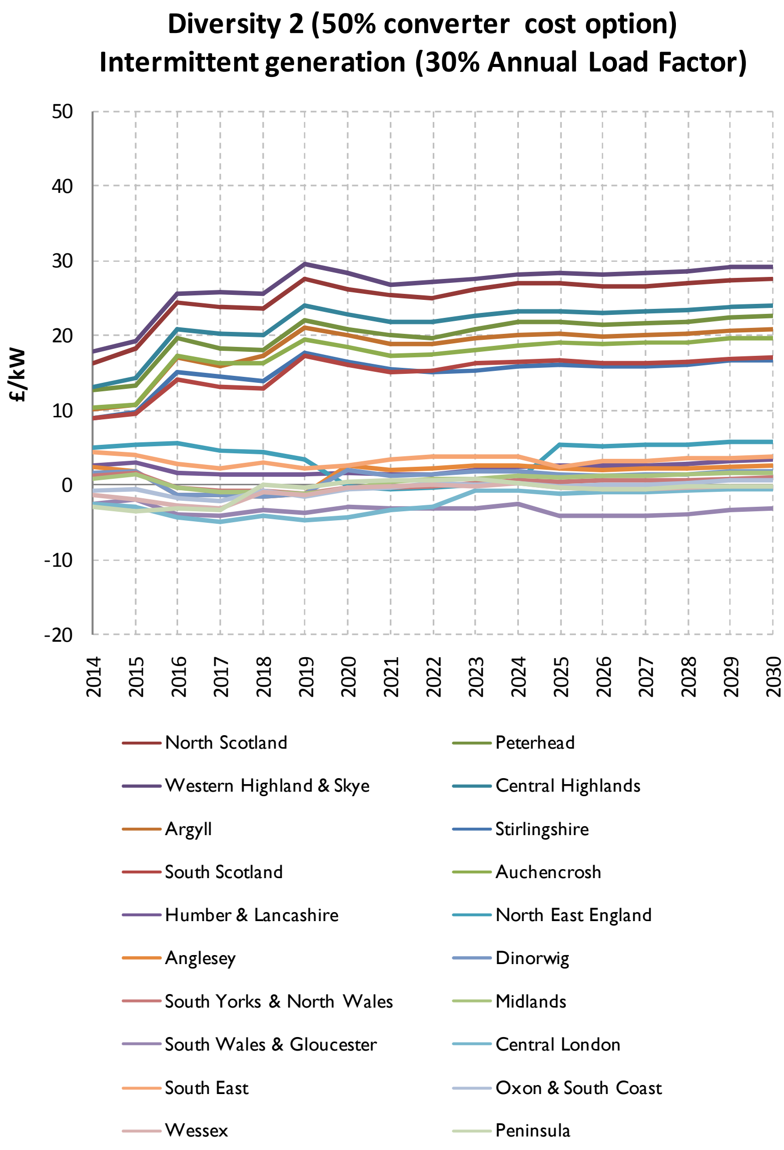

Figure 3.17

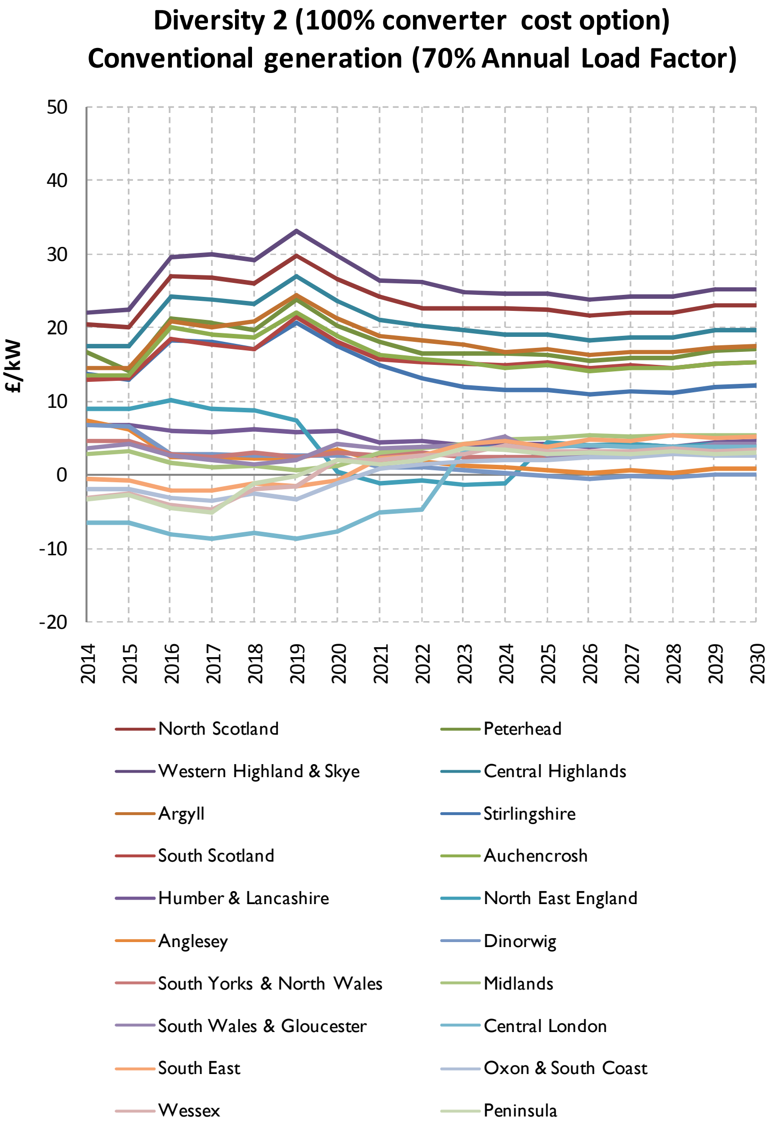

Figure 3.18

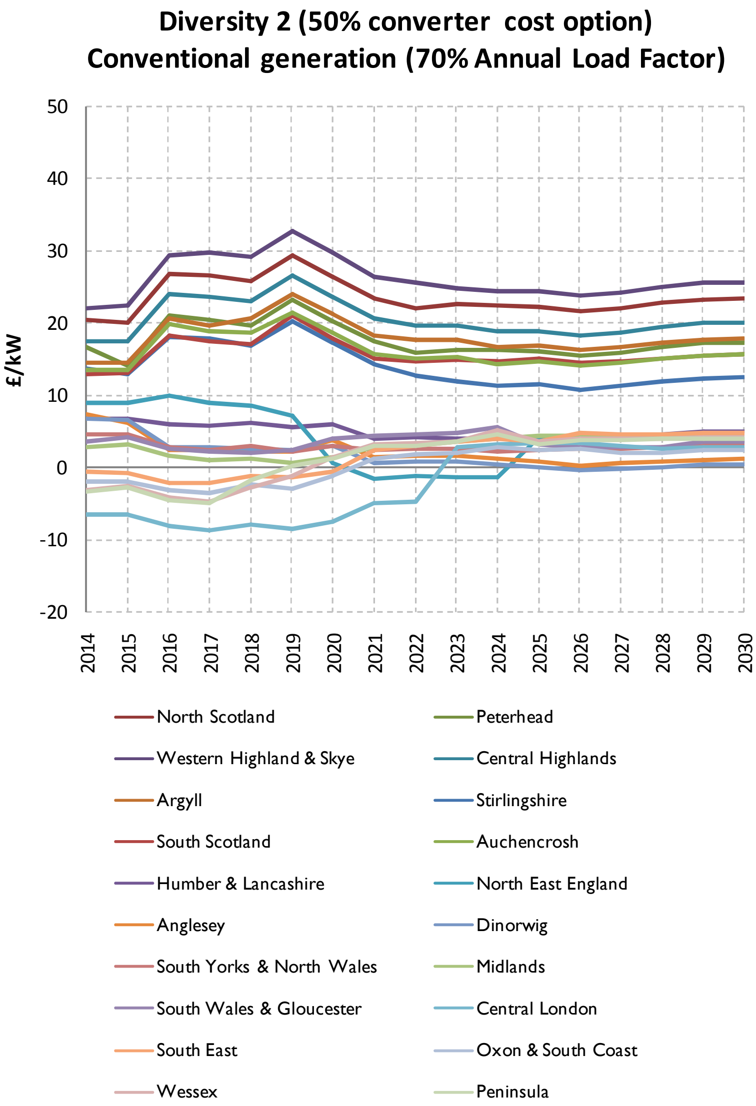

Figure 3.19

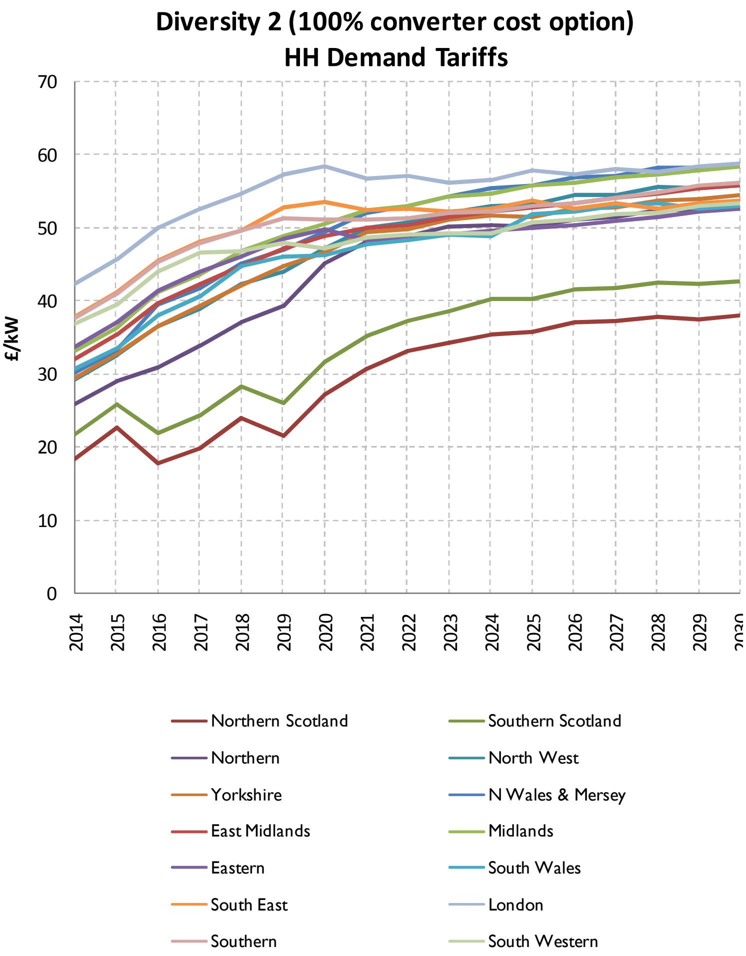

Figure 3.20

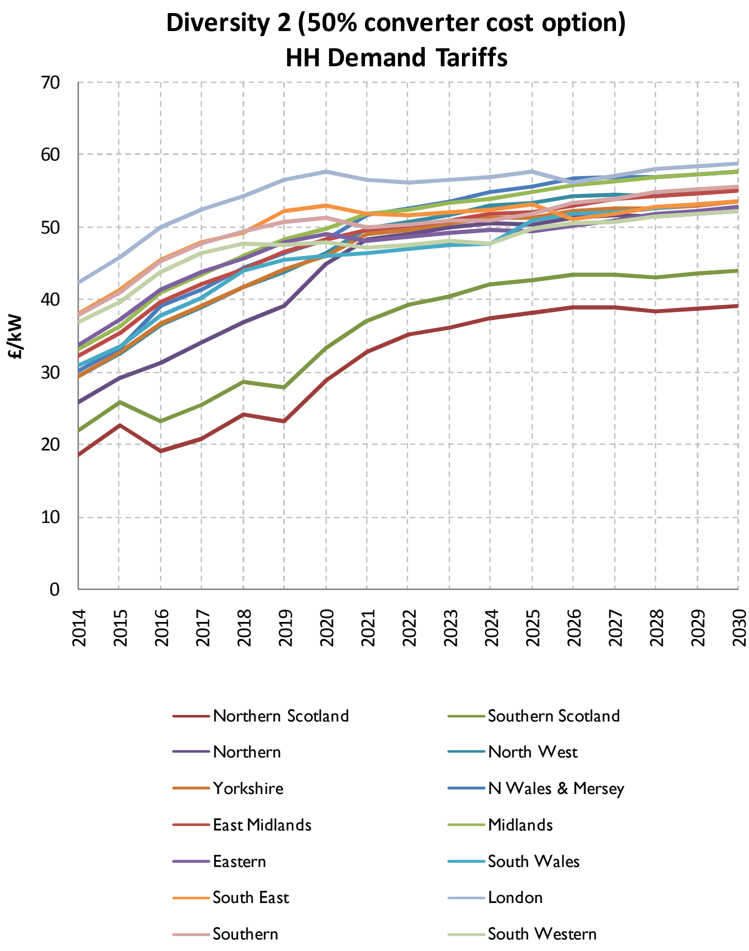

Figure 3.21

3.11 When comparing each set of charts, it is clear that the general shape of the trend in each tariff is similar across these two options. Again, the main difference is that the effect that commissioning of HVDC links has on tariffs under the 50% cost inclusion option is less than that in the 100% option. These results are very similar to those observed for diversity option 1, and when comparing to the charts for the Original modification with the two different treatments of HVDC converter costs, the shape is similar for demand and 70% load factor conventional generation, but the range of resulting tariffs is much greater under the diversity options. The following tables list the major year on year tariff changes, with the exception of year on year changes in demand tariffs* which follow a similar trend to the allowed revenue, as discussed for the Status Quo model.

* Where changes due to allowed revenue changes are included above, this is to provide an indication of the effect of each individual event that changes tariffs within a year.

Year	Zones effected	Change (100% Converter Cost Model)	Change (50% Converter Cost Model)	Tariff	Driver
2016	G1-8	+£4.6-6.7/kW	+£4.5-6.5/kW	30% Int. Gen	Commissioning of Western HVDC link
2016	G9 & G11-19	-£0.8-3.2/kW	-£0.8-3.2/kW	30% Int. Gen	
2016	G1-8	+£5.2-7.1/kW	+£5.0-6.9/kW	70% Con. Gen	
2016	G9 & G11-20	-£0.8-3.9/kW	-£0.8-3.8/kW	70% Con. Gen	
2016	D1-2	-£3.8-4.1/kW	-£2.6-3.6/kW	HH Demand	
2016	D3-14	+£1.7-6.1/kW	+£2.1-5.8/kW	HH Demand	
2017	G1-20	-£0.5/kW	-£0.4/kW	30% Int. Gen & 70% Con. Gen	Decrease in generation residual, due to >27% of additional offshore MAR being collected through local charges.
2017	G3	+£0.5/kW	+£0.5/kW	30% Int. Gen	2GW additional wind generation connecting in Scotland.
2017	G1, G3-4, & G6	-£0.1-0.3/kW	-£0.1-0.3/kW	30% Int. Gen	2GW additional wind generation connecting in Scotland & a 550MW TEC reduction from conventional Scottish generation (transfer between shared and not-shared MWkm).
2017	G1, G3-4, & G6	+£0.2-1.1/kW	+£0.1-1.0/kW	70% Con. Gen	
2017	G5, G7-8 & G10	-0.5-0.7/kW	-£0.6-0.7/kW	30% Int. Gen	4GW of TEC reductions from Northern generation, and introduction of 1.2GW additional offshore and 760MW of CCGT in more Southerly zones.
2017	G5, G7-8 & G10	-0.4-0.7/kW	-£0.5-0.7/kW	70% Con. Gen	
2018	G5	+£1.3/kW	+£1.3/kW	30% Int. Gen	Connection of 400MW of offshore wind generation in zone 5.
2018	G15-20	+£0.8-3.7kW	+£0.8-3.4kW	30% Int. Gen	Connection of largely southern based Offshore wind (1GW under 100% model converter cost model and 600MW under the 50% model) and an additional French interconnector
2018	G15-20	+£0.8-4.0kW	+£0.0-3.3kW	70% Con. Gen	

Year	Zones effected	Change (100% Converter Cost Model)	Change (50% Converter Cost Model)	Tariff	Driver
2019	G1-8	+£3.1-4.3/kW	+£3.1-4.3/kW	30% Int. Gen	Commissioning of Eastern HVDC link
2019	G10 & G13-19	-£0.4-1.1/kW	-£0.4-1.0/kW	30% Int. Gen	
2019	G1-8	+£3.2-4.4/kW	+£2.9-4.0/kW	70% Con. Gen	
2019	G9-14 & G16-G18	-£0.1-1.3/kW	-£0.1-1.5/kW	70% Con. Gen	
2019	D1-2	-£4.1-4.3/kW	-£2.7-2.8/kW	HH Demand	
2019	D3, D5, D7-9 & D11-12	+£0.0-1.1/kW	+£0.4-1.0/kW	HH Demand	
2019	D1-14	+~£1.9/kW	+~£1.9/kW	HH Demand	Increase in allowed revenue*
2020	G1-8 & G10	-£0.8-3.5/Kw	-£0.9-3.5/kW	30% Int. Gen	3.3GW of TEC reductions for Northern generation, and commissioning of 1.7GW of Southern based nuclear generation and additional Irish interconnector (1GW).
2020	G9 & G11-20	+£0.2-3.9/kW	+£0.2-3.9/kW	30% Int. Gen	
2020	G1-8 & G10	-£3.1-6.8/kW	-£2.8-6.4/kW	70% Con. Gen	
2020	G9 & G11-20	+£0.1-3.5/kW	+£0.5-2.6/kW	70% Con. Gen	
2021	G1-G12	-£0.2-1.5/kW	-£0.2-1.5/kW	30% Int. Gen	1.5GW of TEC reductions from Northern generation, and commissioning of 1.7GW of nuclear and 5.6GW of new CCGT generation across the South. Also has decreasing effect on Southern Demand tariffs. It is worth noting that 1.6GW of CCGT connects along the South Coast and in the South West under the 50% model as opposed to in East Anglia under the 100%, which has an additional increasing effect on peak security generation tariffs in the South West.
2021	G1-G12	-£1.5-3.4/kW	-£2.0-3.4/kW	70% Con. Gen	
2021	G13-14 & G16-20	+£0.1-1.1/kW	+£0.1-1.1/kW	30% Int. Gen	
2021	G14 & G16-19	+£0.1-2.9/kW	+£1.2-3.0/kW	70% Con. Gen	
2025	G10	+£4.9/kW	+£4.8/kW	30% Int. Gen	Commissioning of Norwegian

Year	Zones effected	Change (100% Converter Cost Model)	Change (50% Converter Cost Model)	Tariff	Driver
2025	G10	+£5.6/kW	+£5.5/kW	70% Con. Gen	Interconnector (Blyth).
2025	G11-20	-£0.1-1.6/kW	-£0.2-1.5/kW	30% Int. Gen	Combined effect of commissioning of 9GW of generation, including 6.2GW of CCS plant (mainly Midlands & Northern England based), and 1.7GW of nuclear generation in the South East.
2025	G11-12, G15 & G17-20	-£0.1-2.4/kW	-£0.3-2.5/kW	70% Con. Gen	

Table 3.4 – Drivers for changes in diversity 2 tariffs

Diversity 3 (50% and 100% HVDC options)

3.12 The following charts depict tariffs resulting from Diversity option 3 with inclusion of 100% and 50% HVDC converter costs within the expansion factor calculation. These charts show the effect on 30% load factor intermittent and 70% conventional generation.

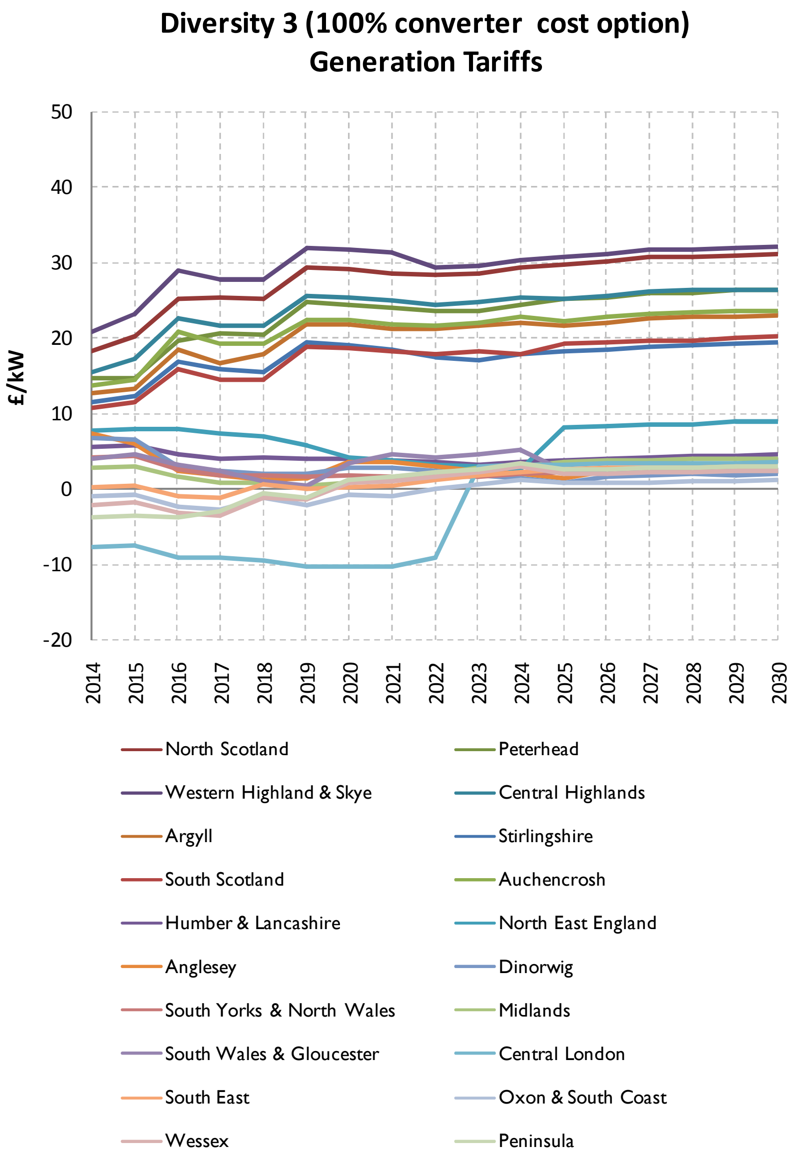

Figure 3.22

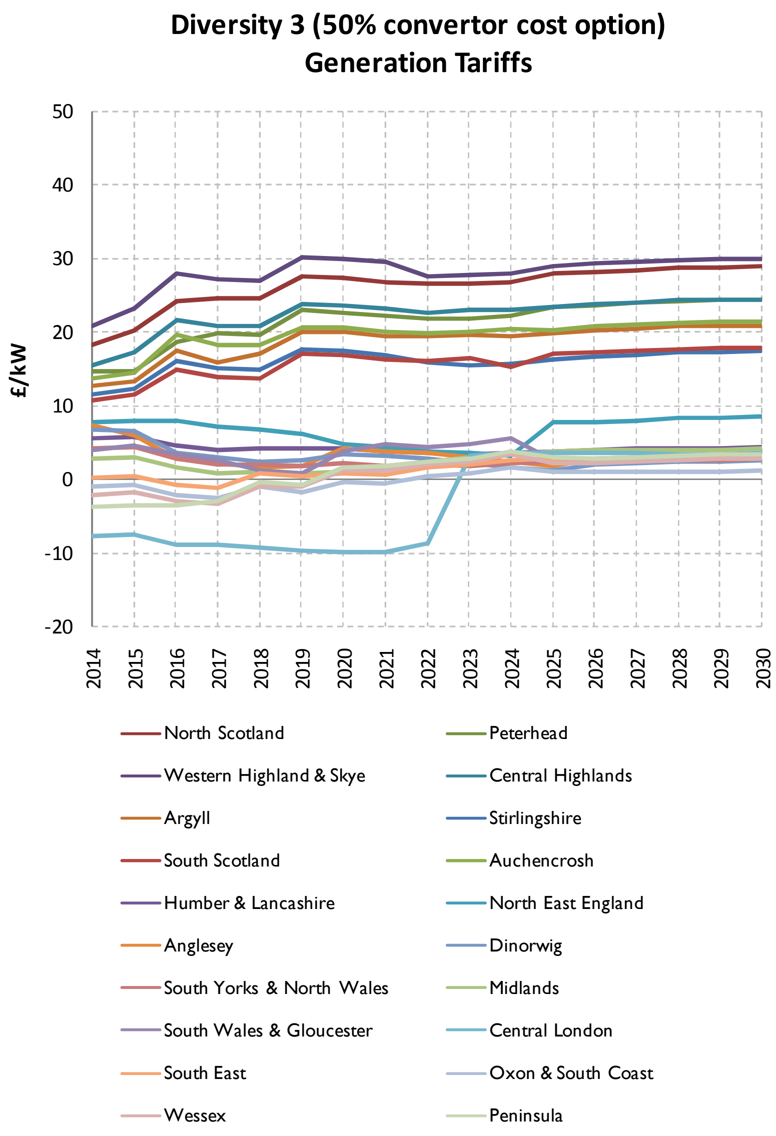

Figure 3.23

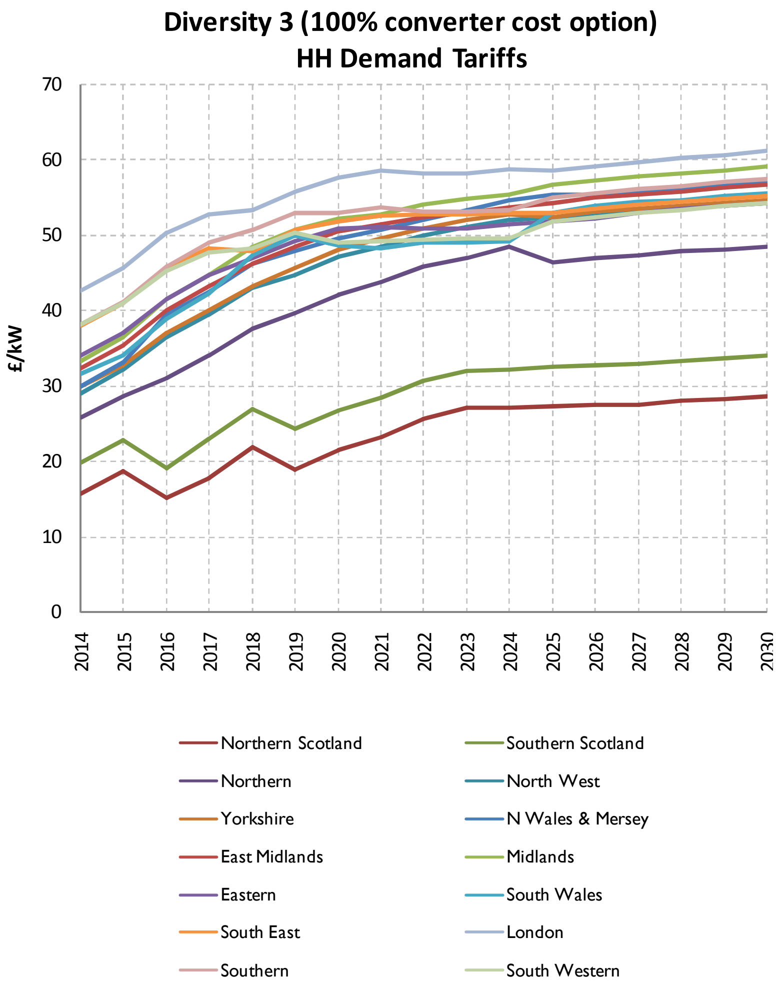

Figure 3.24

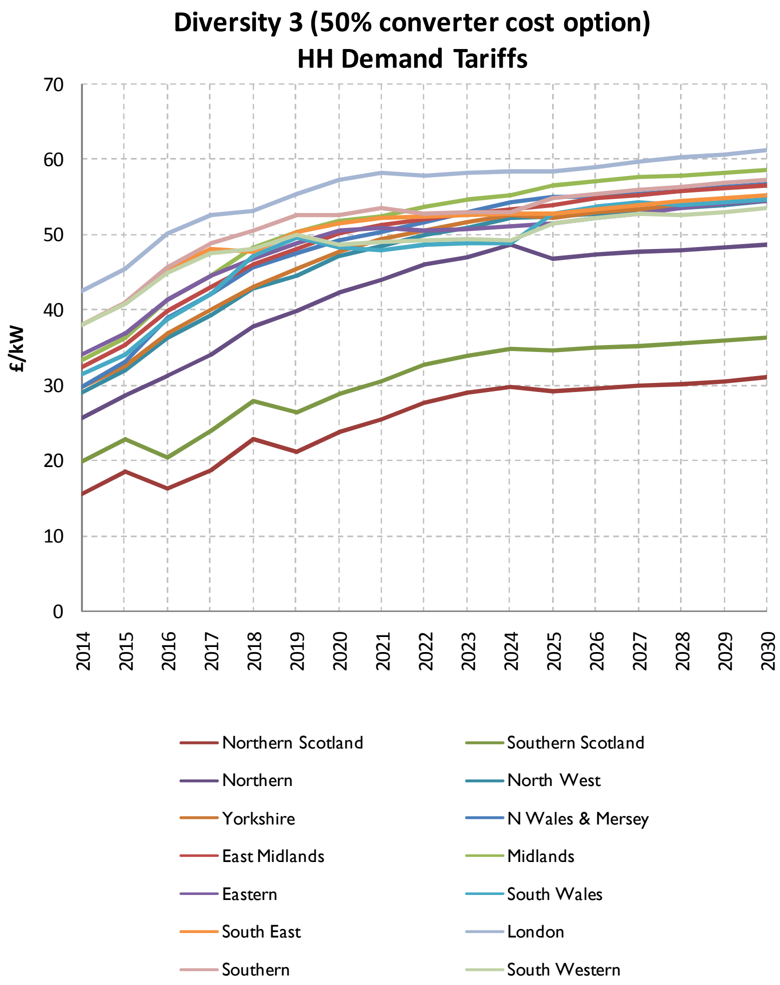

Figure 3.25

3.13 The following table list the major year on year tariff changes, with the exception of year on year changes in demand tariffs* which follow a similar trend to the allowed revenue, as discussed for the Status Quo model.

Year	Zones effected	Change (100% Converter Cost Model)	Change (50% Converter Cost Model)	Tariff	Driver
2016	G1-8	£4.3-6.5/kW	+£3.4-5.3/kW	Generation	Commissioning of Western HVDC link
2016	G9 & G11-20	-£0.2-3.6/kW	-£0.0-3.1/kW	Generation	
2016	D1-3	-£1.6-7.7/kW	-£1.3-6.3/kW	HH Demand	
2016	D4-14	+£0.4-2.5/kW	+£0.3-2.1/kW	HH Demand	
2016	D1-14	+~£3.9/kW	+~£3.9/kW	HH Demand	Increase in allowed revenue*

* Where changes due to allowed revenue changes are included above, this is to provide an indication of the effect of each individual event that changes tariffs within a year.

2017	G1-20	-£0.6/kW	-£0.6/kW	Generation	Decrease in generation residual, due to >27% of additional offshore MAR being collected through local charges.
2017	G1	+£0.9/kW	+£1.0/kW	Generation	500MW of additional wind generation connecting in Northern Scotland & 550MW TEC reduction from Scottish conventional generation (transfer between shared and not-shared MWkm).
2017	G3-10 & G13-15	-£0.0-1.1/kW	-£0.0-0.9/kW	Generation	5.5GW of TEC reductions for Northern generation, 1.6GW of TEC reductions in South Wales and the introduction of 1.2GW additional offshore and 760MW of CCGT in more Southerly zones.
2018	G5	+£1.8/kW	+£1.2/kW	Generation	Connection of 400MW of offshore wind in zone 5
2018	G17-20	+£1.6-2.4/kW	+£1.6-2.4/kW	Generation	Connection of 1GW of largely southern based Offshore wind and additional French interconnector
2019	G1-8	+£3.2-4.3/kW	+£2.4-3.2/kW	Generation	Commissioning of Eastern HVDC link
2019	G9-10 G13-20	-£0.1-1.1/kW	-£0.0-0.7/kW	Generation	
2019	D1-2	-£4.4-4.7/kW	-£3.2-3.4/kW	HH Demand	
2019	D3, D5 & D7-14	+£0.3-1.0/kW	+£0.1-0.8/kW	HH Demand	
2019	D1-14	+~£1.8/kW	+~£1.8/kW	HH Demand	Increase in allowed revenue*
2020	G1-10	-£0.0-1.6/kW	-£0.0-1.3/kW	Generation	3.3GW of TEC reductions for Northern generation, and commissioning of 1.7GW of Southern based nuclear generation and additional Irish interconnector (1GW).
2020	G11-20	+£0.0-3.0/kW	+£0.0-3.0/kW	Generation	
2025	G10	+£5.5/kW	+£4.5/kW	Generation	Commissioning of Norwegian Interconnector (Blyth).
2025	G11-12, G15 & G18-20	-£0.6-2.9/kW	-£0.5-3.0/kW	Generation	Combined effect of commissioning of 9GW of generation, including 6.2GW of CCS plant (mainly Midlands & Northern England based), and 1.7GW of nuclear generation in the South East.

Table 3.5 – Drives for changes in diversity 3 tariffs

Tariff comparison across sharing model alternatives

Generation Tariffs

3.14 Figures 3.25 – 3.30 below show the relative wider zonal generation tariffs for each of the modelled options (under the 100% HVDC converter cost option) in the periods 2014, 2020, and 2030 for both an intermittent generator with an annual load factor (ALF) of 30% and a conventional generator with an ALF of 70%.

3.15 Across all timescales it can be seen that Status Quo provides the greatest range of locational differentials, followed by Diversity 3, then Diversity 1 and 2. The Original provides the lowest, although this is reduced slightly further for 2020 and 2030 tariffs with the Original at 50% option due to the additional socialisation of converter costs.

3.16 Tariffs are identical for both generators under Status Quo and Diversity 3 as these do not account for dual background or the specific load factor of the generator.

3.17 Differentials lessen for Diversity 1 and 2 by 2020 in some zones as there is an increased proportion of the year round not shared element. By 2030, in Scotland it can be observed that the tariffs for the intermittent generator are higher than the conventional, suggesting a negative peak security element. However this reversal does not occur under the Original proposal due to the absence of the year round not-shared element.

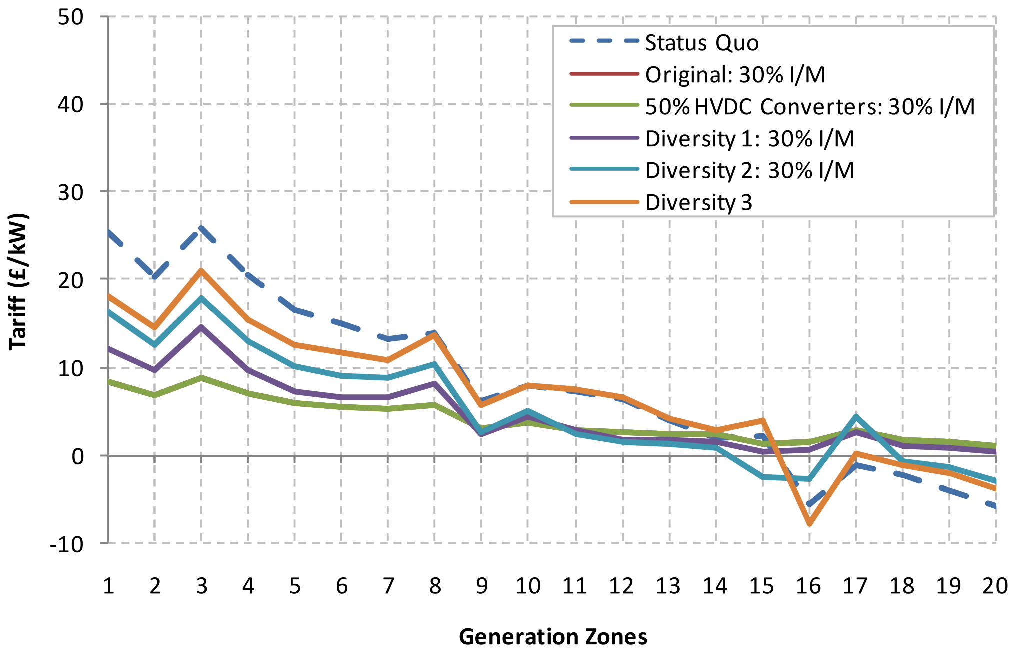

Figure 3.25 –2014 tariffs for 30% ALF intermittent generator

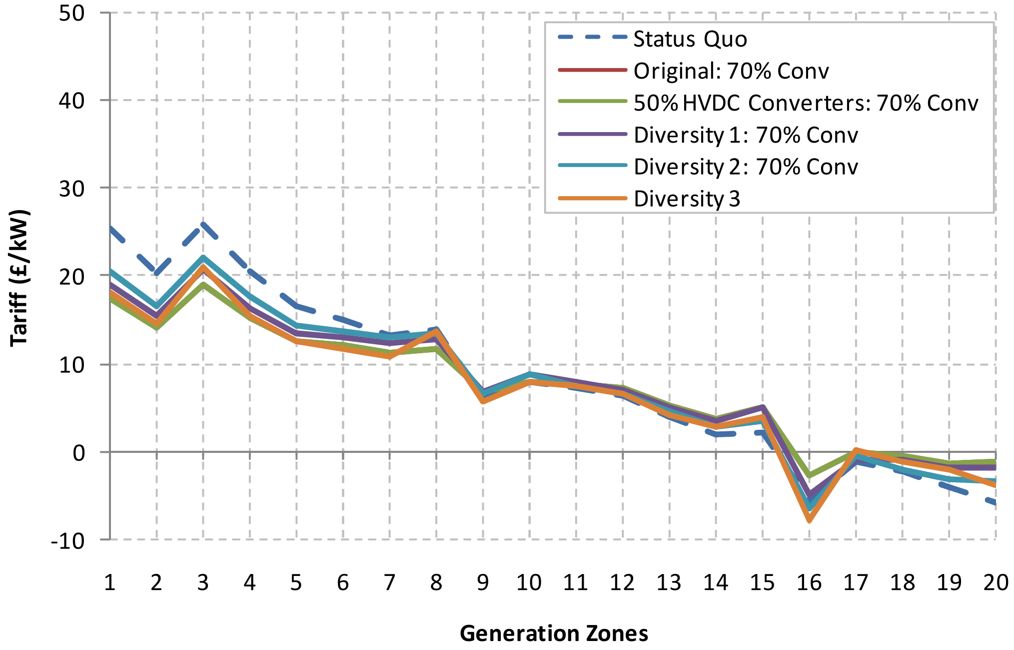

Figure 3.26 –2014 tariffs for 70% ALF conventional generator

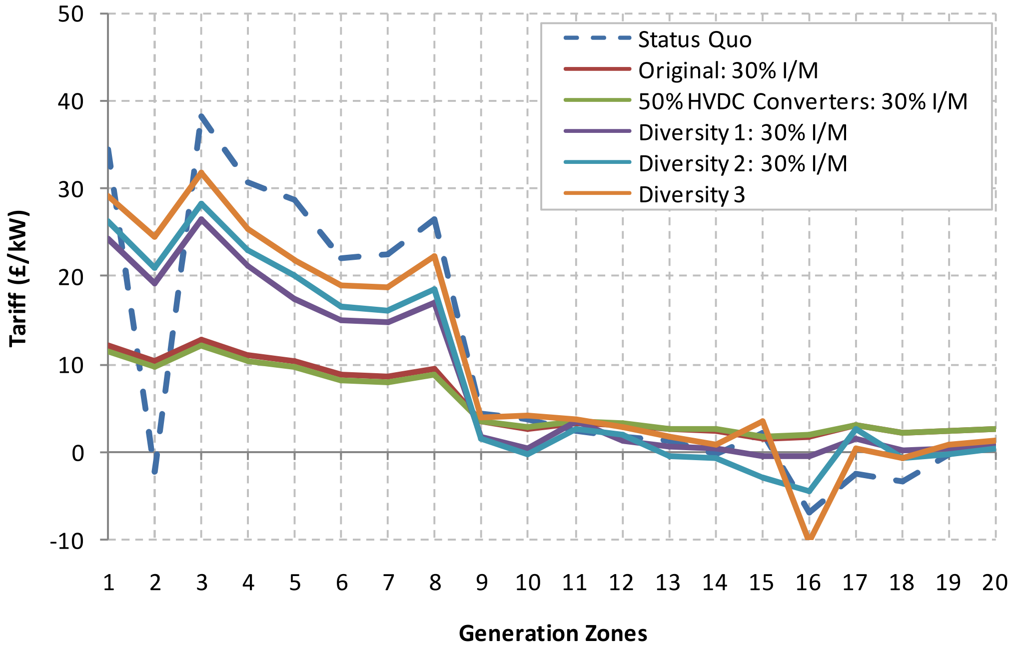

Figure 3.27 –2020 tariffs for 30% ALF intermittent generator

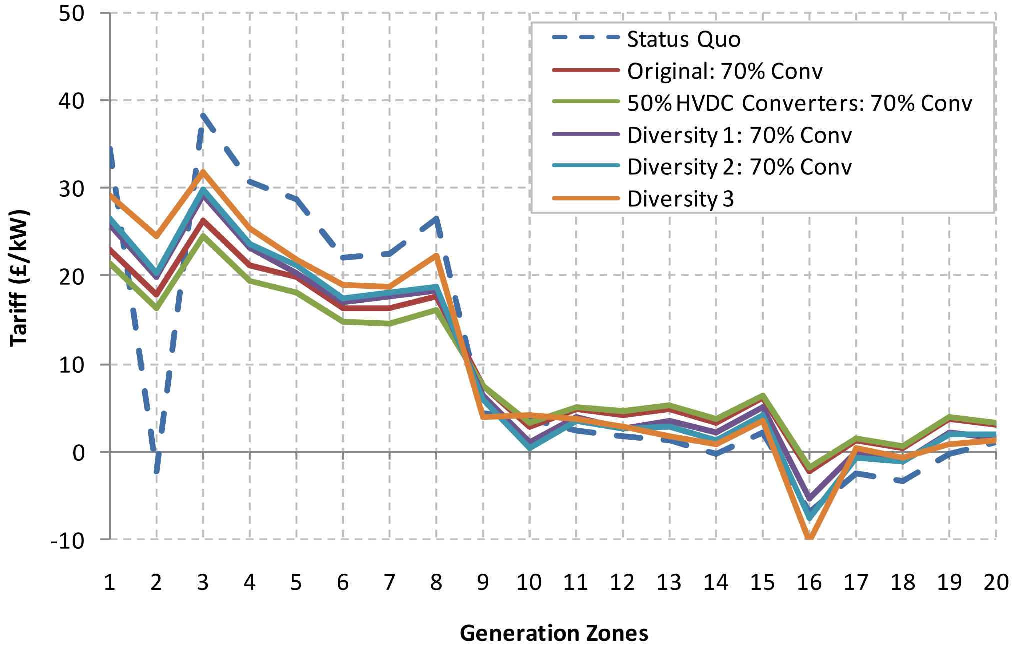

Figure 3.28 –2020 tariffs for 70% ALF conventional generator

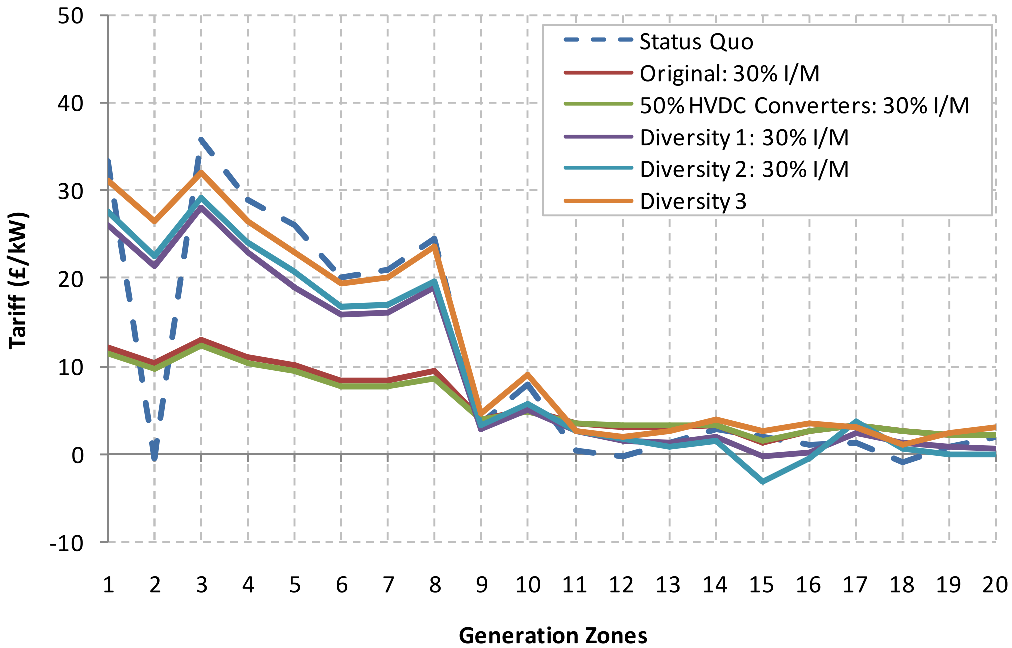

Figure 3.29 –2030 tariffs for 30% ALF intermittent generator

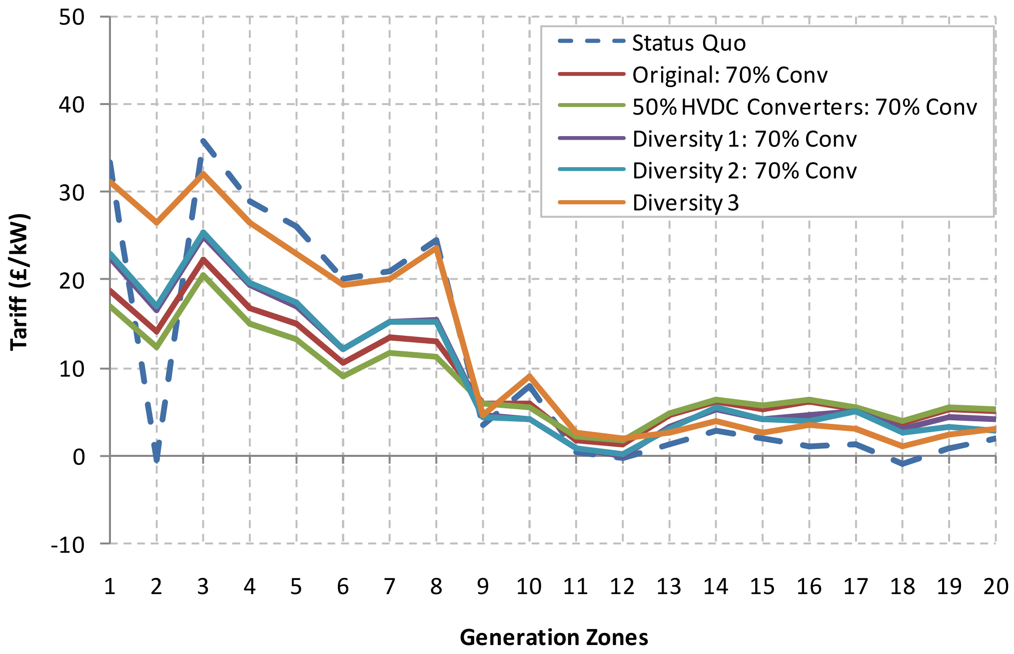

Figure 3.30 –2030 tariffs for 70% ALF conventional generator

Demand Tariffs

3.18 Figures 3.31 – 3.36 below show the relative wider zonal demand tariffs for each of the modelled options (under the 100% HVDC converter cost option) in the periods 2014, 2020, and 2030 for both NHH and HH demand customers.

3.19 These figures have been re-run from the information presented in the Code Administrator consultation as it was found that there were different demand bases in Diversity 1 and Diversity 2 tariff models. The demand bases were aligned to the Status Quo model, and it has been confirmed that all other modelling results remain valid.

3.20 It can be readily observed that there are no significant changes between the tariffs for any modelled alternative.

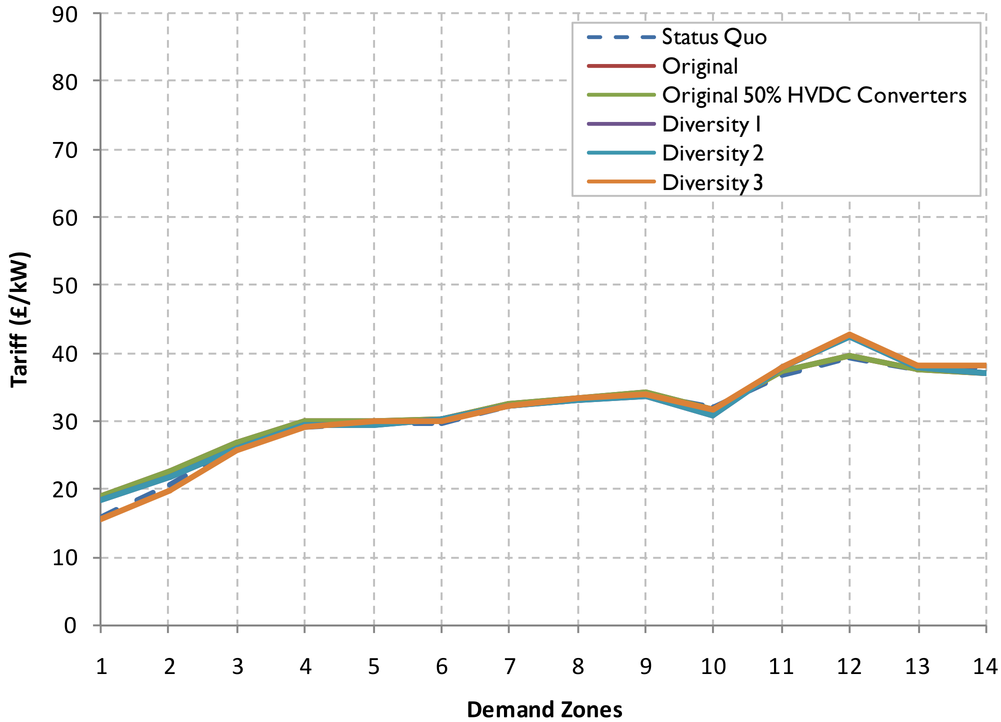

Figure 3.31 –2014 demand HH tariffs

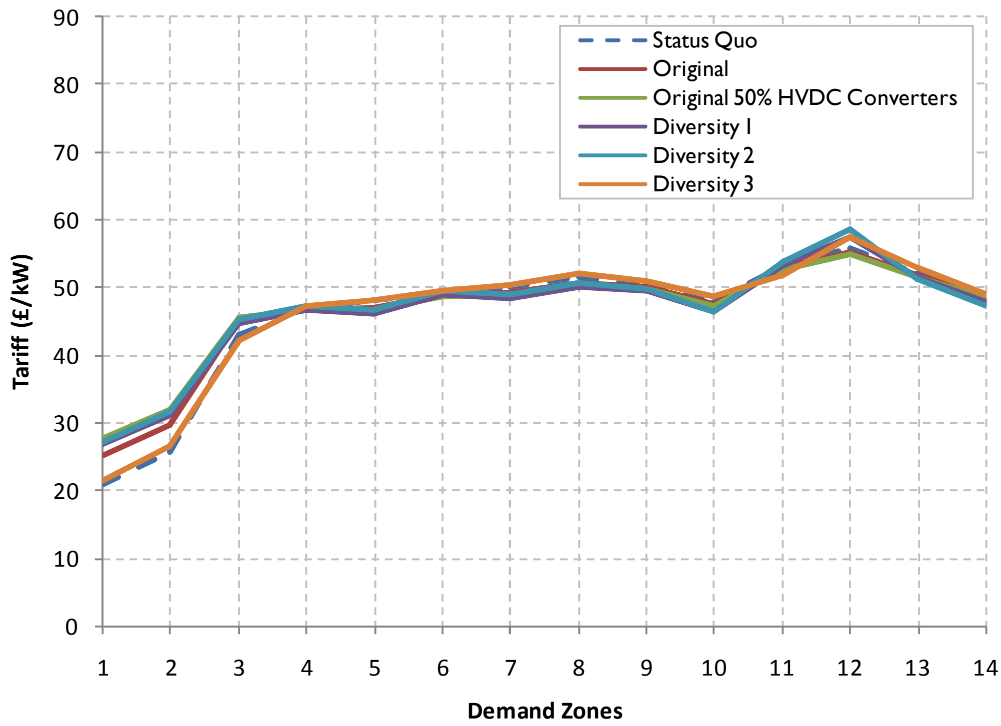

Figure 3.32 –2020 demand HH tariffs

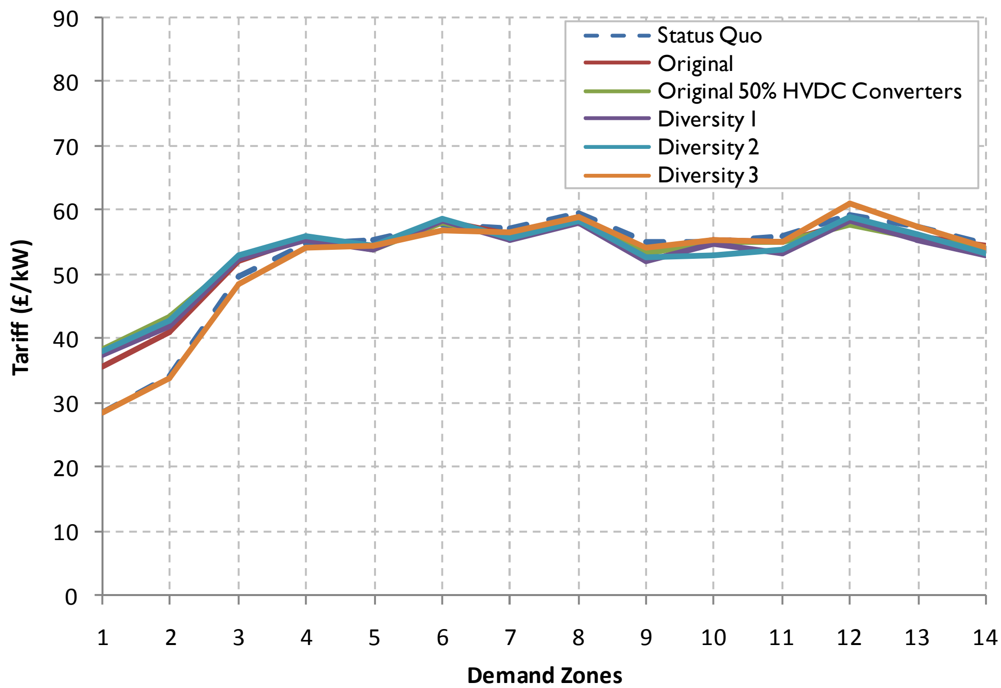

Figure 3.33 –2030 demand HH tariffs

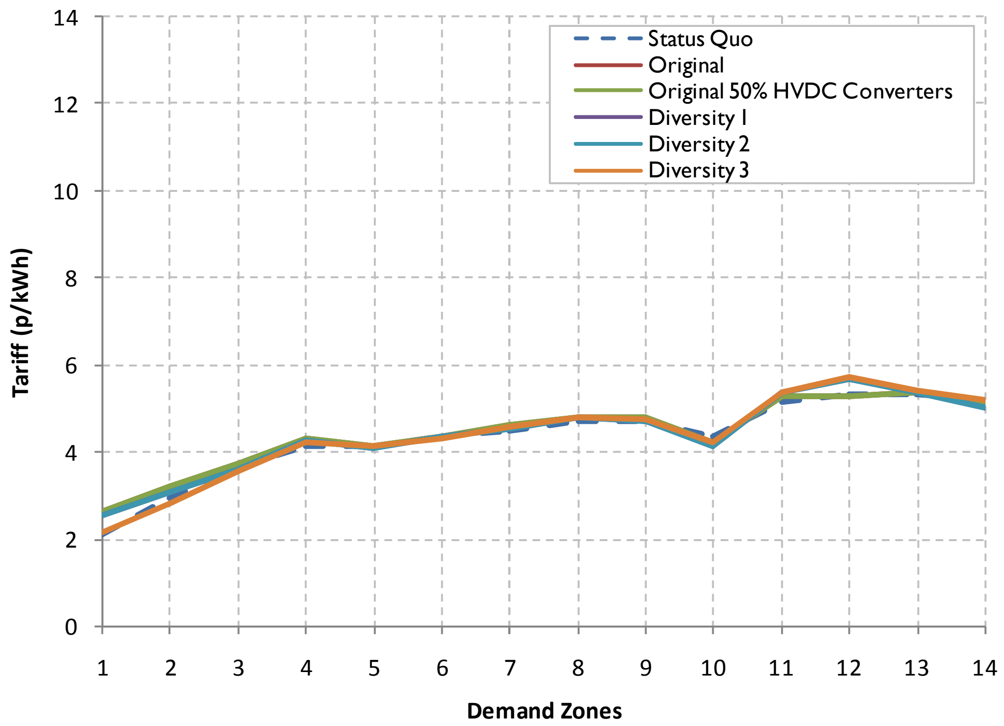

Figure 3.34 –2014 demand NHH tariffs

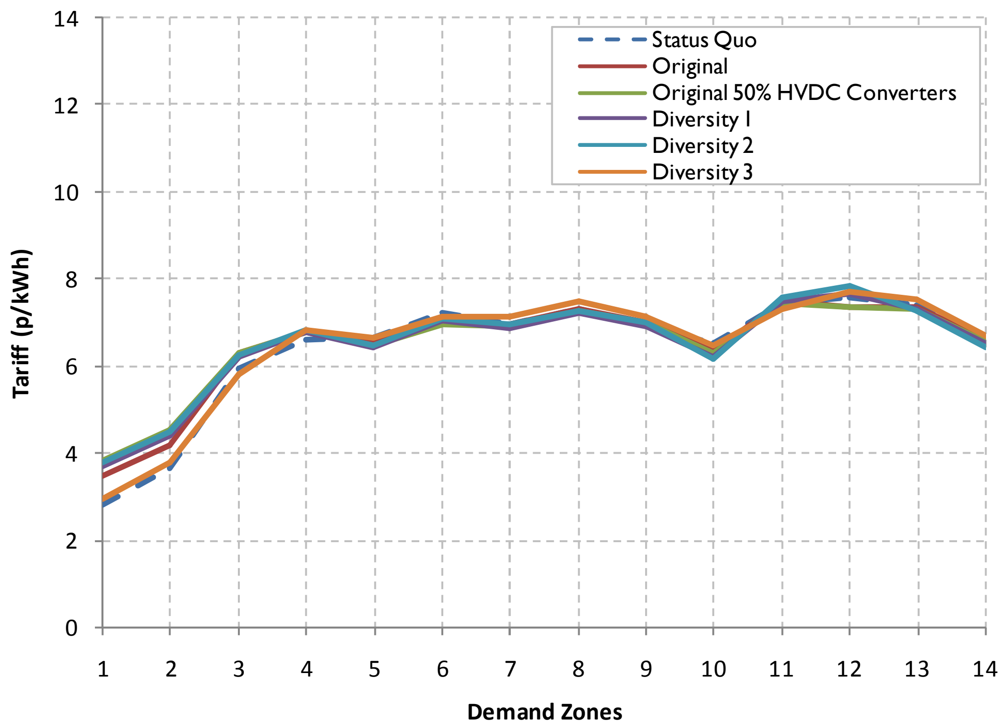

Figure 3.35 –2020 demand NHH tariffs

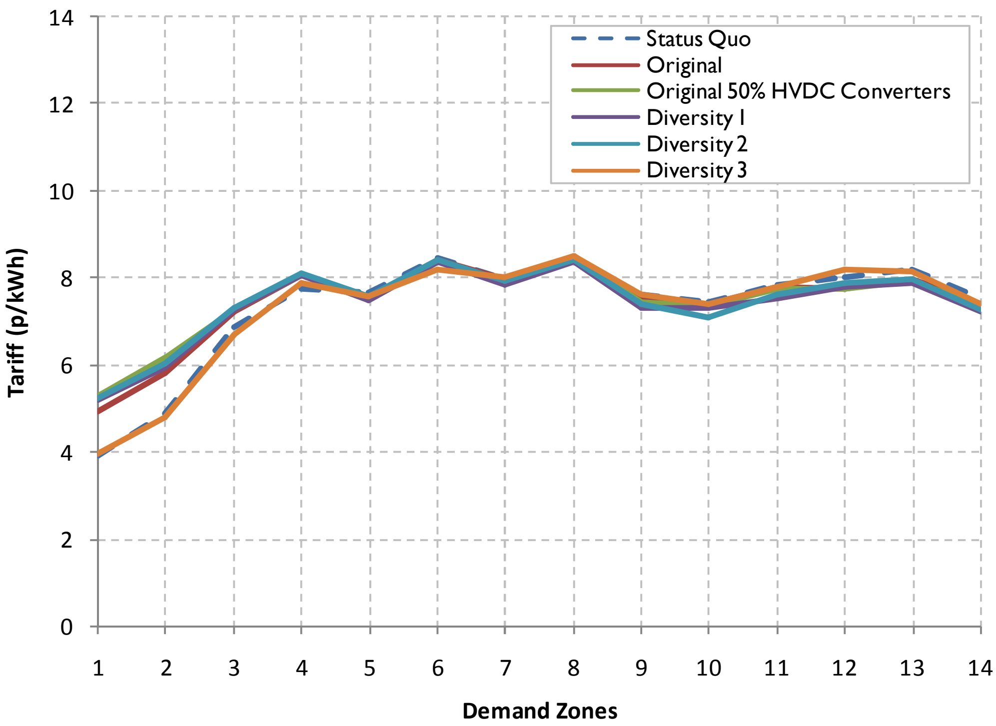

Figure 3.36 –2030 demand NHH tariffs

4 Generation Decisions

Generation build decisions

4.1 Generation builds under Status Quo and the Original models are shown in Figures 4.1 and 4.2 below. The generation builds for other modelled alternatives are similar.

CCGT Build

4.2 Investment in CCGT is driven by profitability in the wholesale electricity market and revenues from Capacity Payments. The differences in transmission charges for CCGTs between modelled alternatives is small compared to these revenue streams. As a result there are no significant differences in capacity built or in the location of that capacity other than in Diversity 3, where 2.7 GW more CCGT capacity is built by 2030. This is offset by the retirement of an additional 3.2 GW of older existing CCGT between 2021 and 2026.

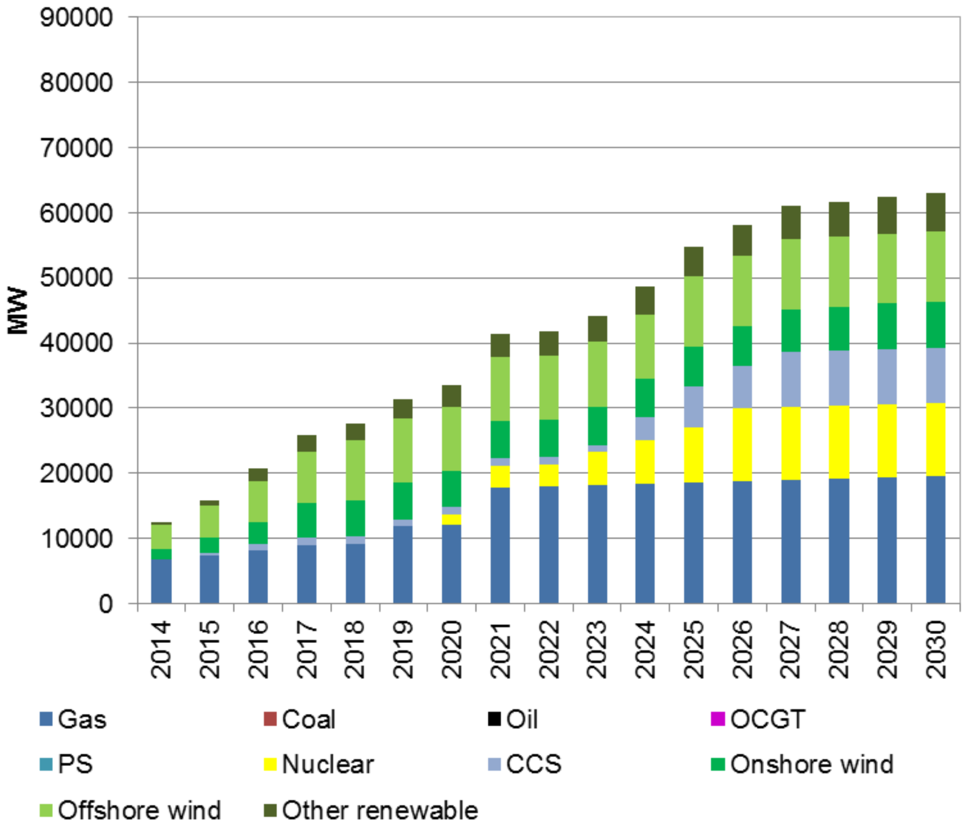

Figure 4.1 –New generation build (Status Quo)

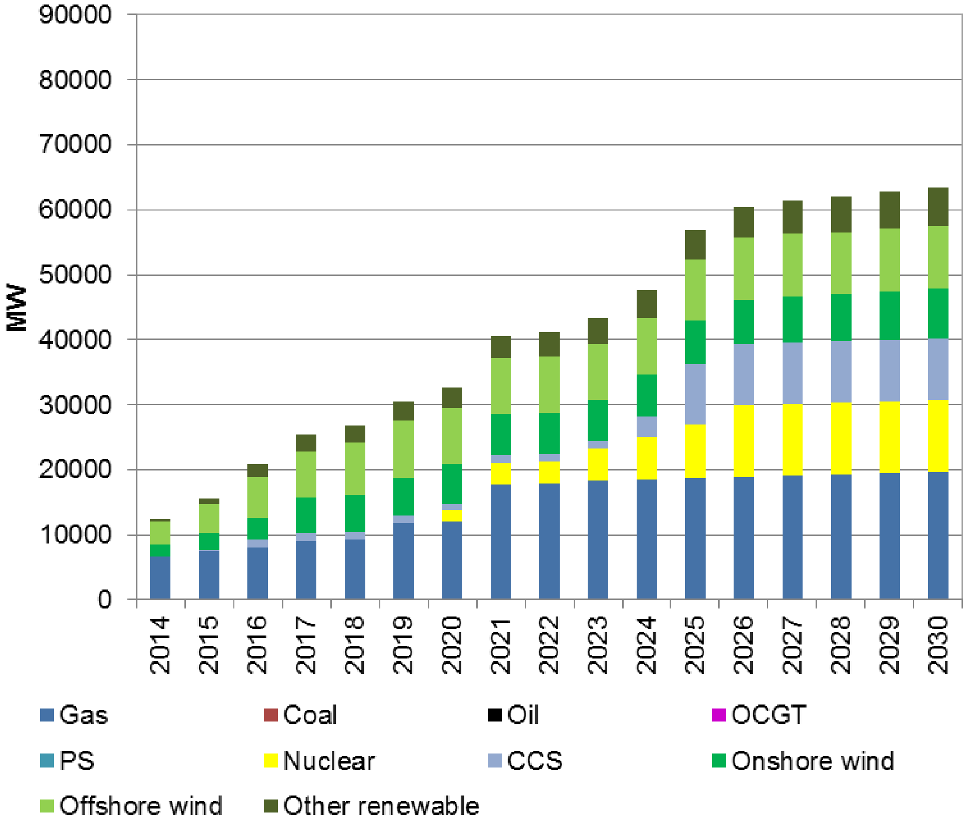

Figure 4.2 –New generation build (Original)

Low carbon build

4.3 The total level of low carbon build is defined mainly by the sustainability goals of 30% renewable generation in 2020 and carbon intensity of 100g/kWh in 2030.

4.4 The total installed capacity of renewables under Status Quo is shown in Table 4.1. The Original has more onshore wind and less offshore wind than Status Quo. In total the renewable capacity (and generation) is slightly lower under the Original than Status Quo. This difference is maintained for the Original 50% HVDC option. Of the Diversity options, Diversity 1 is closest to the Original in terms of renewables capacity and Diversity 3 is most similar to Status Quo. Under the Diversity options, there is no growth in offshore wind after 2020.

Year	Technology	Status Quo	Original	Original 50% HVDC Converters	Diversity 1	Diversity 2	Diversity 3
2020	Onshore wind	9.6	10.1	10.1	9.9	9.9	9.9
	Offshore wind	11.3	10.1	10.1	10.1	10.9	11.3
	Other renewable	6.6	6.6	6.6	6.6	6.6	6.6
2030	Onshore wind	11.1	11.7	11.8	11.4	11.4	11.4
	Offshore wind	12.2	11.0	11.0	10.1	10.9	11.3
	Other renewable	9.3	9.3	9.3	9.3	9.3	9.3

Table 4.1 –Renewables total capacity

4.5 The additional onshore wind under the Original and Alternatives is located in North Scotland. This is where tariffs are reduced most under the Original compared to Status Quo.

Original (change from Status Quo)	2015	2020	2025	2030
Onshore wind - S England	0	0	0	0
Onshore wind - Midlands & N Wales	0	0	0	0
Onshore wind - N England	0	0	0	0
Onshore wind - S Scotland	0	0	0	0
Onshore wind - N Scotland	77	443	443	601

Table 4.2 –Regional onshore wind build (Original)

4.6 This increase in onshore wind is lower for the Diversity options, as shown in Table 4.3.

Diversity 1, 2 & 3 (change from Status Quo)	2015	2020	2025	2030
Onshore wind - S England	0	0	0	0
Onshore wind - Midlands & N Wales	0	0	0	0
Onshore wind - N England	0	0	0	0
Onshore wind - S Scotland	0	0	0	0
Onshore wind - N Scotland	77	284	284	284

Table 4.3 –Regional onshore wind build (Diversity 1, 2 & 3)

4.7 Under the Original, the reduction in offshore wind is in the south of England. In this part of the system, tariffs generally increase under the Original compared to Status Quo.

Original (change from Status Quo)	2015	2020	2025	2030
Offshore wind - Offshore South	-500	-1,170	-1,170	-1,170
Offshore wind - Offshore Irish Sea	0	0	0	0
Offshore wind - Offshore E England	0	0	0	0
Offshore wind - Offshore Scotland	0	0	0	0

Table 4.4 –Regional offshore wind build (Original)

4.8 Under the Diversity options, there is no growth in offshore wind after 2020, so compared to Status Quo there is a reduction of 905MW from 2025.

Diversity 1(change from Status Quo)	2015	2020	2025	2030
Offshore wind - Offshore South	0	-1,170	-1,170	-1,170
Offshore wind - Offshore Irish Sea	0	0	0	0
Offshore wind - Offshore E England	0	0	0	0
Offshore wind - Offshore Scotland	0	0	-905	-905

Table 4,5 –Regional offshore wind build (Diversity 1)

4.9 Table 4.6 shows the total installed capacity of nuclear and CCS in each of the options. The results are almost identical across the options apart from the following differences;

- The Original and Alternatives have 0.9 GW additional CCGT + CCS capacity by 2030. There is 2 GW additional CCGT +CCS in 2025 and 2026 due to earlier deployment.
- Diversity 3 has 0.4 GW additional nuclear capacity by 2030 (loss of a project in Midlands & North Wales region, gain of a larger station in South England)

Year	Technology	Status Quo	Original	Original 50% HVDC Converters	Diversity 1	Diversity 2	Diversity 3
2020	Nuclear	7.6	7.6	7.6	7.6	7.6	7.6
	Coal + CCS	1.1	1.1	1.1	1.1	1.1	1.1
	CCGT + CCS	0.0	0.0	0.0	0.0	0.0	0.0
2030	Nuclear	14.8	14.8	14.8	14.8	14.8	15.2
	Coal + CCS	5.0	5.0	5.0	5.0	5.0	5.0
	CCGT + CCS	3.4	4.3	4.3	4.3	4.3	4.3

Table 4.6 –Nuclear and CCS total capacity

4.10 The difference in CfD strike prices for CCS is very small across the modelled alternatives. The largest difference is for the Original where CfD strike prices for CCGT + CCS are only £0.50/MWh higher than under Status Quo. This difference offsets the average increase in transmission charges that CCGT + CCS face under the Original (being high load factor plant located either in the south or in north England). The overall increase and earlier deployment of CCS capacity in the Original and the Alternatives appears to arise from North England CCS projects benefiting from a higher strike price whilst not receiving a corresponding increase in transmission charges.

Generation closure decisions

4.11 Generator closure decisions are influenced by the overall profitability of the generator, with the key drivers being revenues from the wholesale electricity market and from the Capacity Mechanism, as well as restrictions on operation or load factors due to SOx and NOx emission limits.

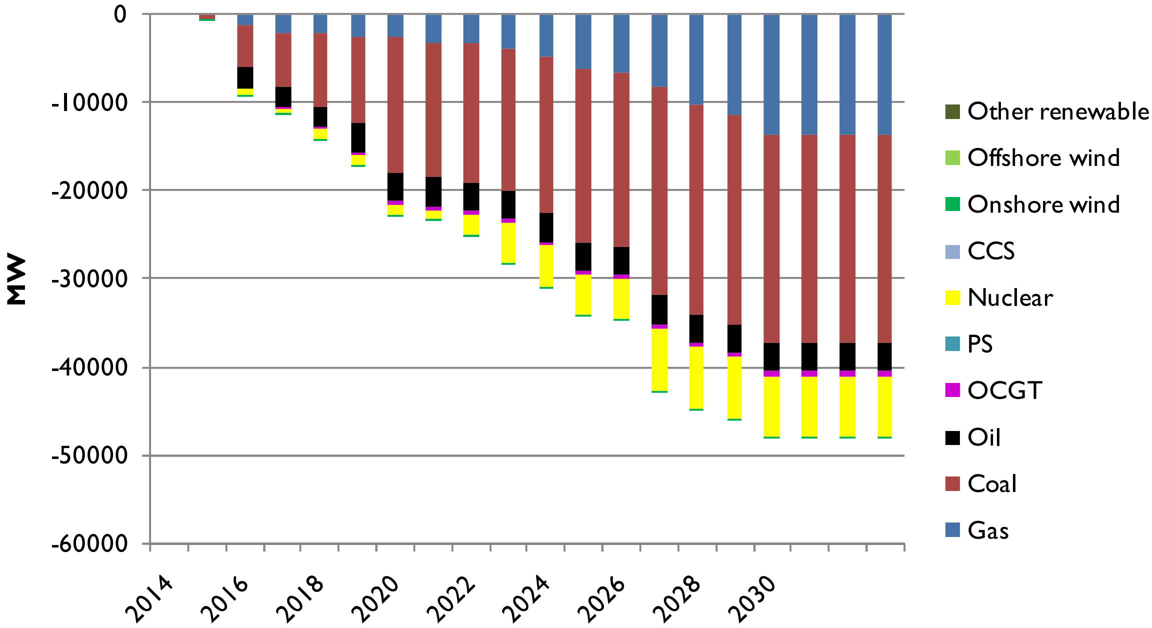

Figure 4.3 –Generation retirements (Status Quo)

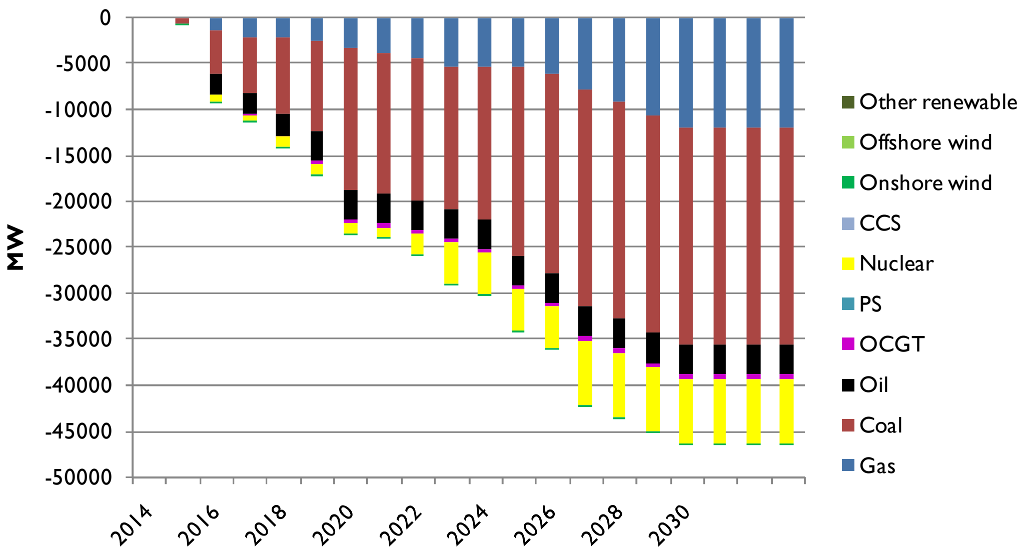

Figure 4.4 –Generation retirements (Original)

4.12 The changes to transmission charging impact on marginal retirement decisions only, and therefore whilst the transmission charges may change the overall profitability for all generators, the changes in these tariffs cause limited differences in the retirement decisions. Typically this brings forward or defers a retirement by a few years. For example, under the Original, the retirement of coal capacity located in Scotland is delayed from 2019 under Status Quo to 2023, whilst Midlands and North England CCGT capacity retires four years earlier over a similar timeframe.

4.13 Under Diversity 3, there is the additional retirement of 3.2 GW of older existing CCGT between 2021 and 2026 in South England & South Wales and North England. This is closely related to additional investment in CCGT. It appears that the capacity payment requirements are closely matched (with new CCGT earning more revenue from the wholesale market but needing to cover investment costs).

Transmission reinforcement costs

5.1 The cost of reinforcements to the onshore network is shown in Figure 5.1 for the six modelled options. Reinforcements are identical up to 2019. After 2019 the Original and Alternatives bring forward the East Coast Upgrade relative to the Status Quo. This upgrade reinforces internal Scottish boundaries and is due to the increased volume of onshore renewables using in this part of the system.

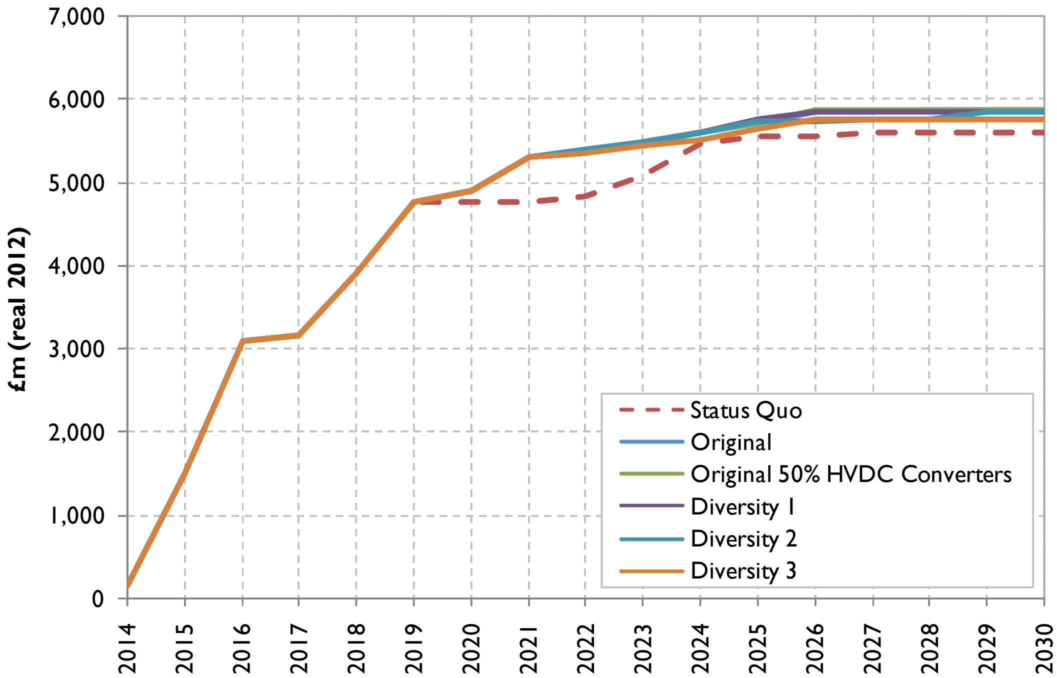

Figure 5.1 - Transmission investment

5.2 The commissioning of HVDC bootstraps is the same under all options. The Western HVDC is assumed to be pre-committed and is commissioned in 2016. The model chooses to commit the Eastern HVDC bootstrap 2 in all model runs, and this is commissioned in 2019.

5.3 Offshore transmission is directly matched to offshore wind generation build. Given the lower offshore wind build under Original and the Alternatives, there is a reduced level of offshore transmission investment.

Transmission constraint costs

5.4 Constraint costs are shown in Figure 5.2. Constraint costs are mainly due to constraints on the B6 and B7a boundaries, which are then reduced by the commissioning of the HVDC bootstraps. The costs are close to zero for a long period because of the slow down in the rate of onshore wind build after 2020.

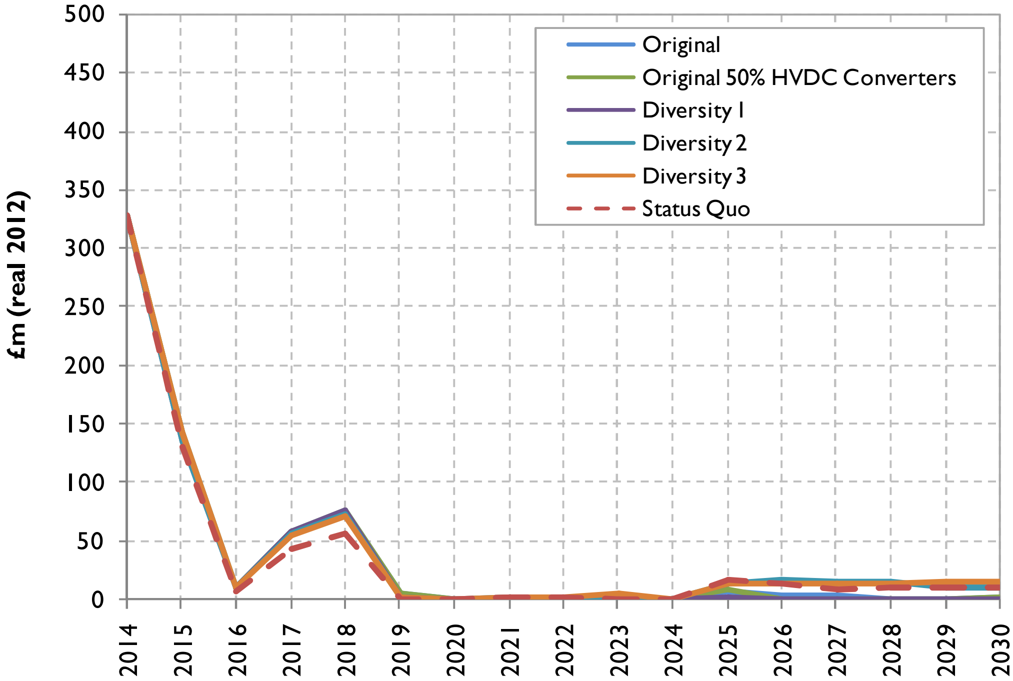

Figure 5.2- Constraint costs

Transmission losses

5.5 The transmission losses for the six model runs are shown in Figure 5.3 below. All six models follow the same trend, with small differences due to differences in onshore wind capacity that is located far from centres of demand.

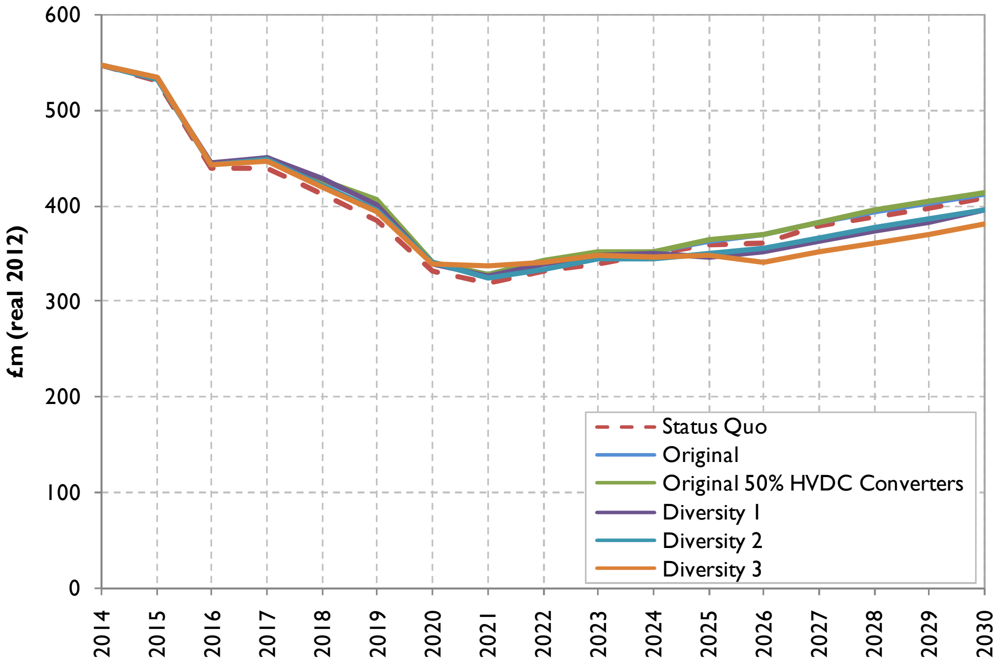

Figure 5.3 - Transmission losses

6 Power Sector Costs

Period 2014-2020

6.1 Table 6.1 presents the power sector costs for the Original and the four modelled alternatives in the period 2014-2020 relative to a baseline of the Status Quo model.

6.2 For the Original there is an overall saving in power sector costs. The major saving is in generation costs (£958m), which is mainly due to savings in capital expenditure caused by the replacement of offshore wind with onshore wind. The slightly lower overall renewable level under the Original as compared to Status Quo also reduces generation costs as this presents the Original option in a more favourable light than if the renewable generation matched exactly.

6.3 Onshore MITS transmission reinforcement costs are the same for Status Quo and the Original. The savings in transmission costs (£137m) are due to a reduction in OFTO costs due to lower offshore wind build. This is offset slightly by increases in transmission losses.

6.4 Constraint costs are higher by £40m under the Original.

6.5 The increase in carbon costs under the Original is again a result of having slightly less renewable generation.

6.6 Of the four modelled alternatives, Original 50% HVDC and Diversity 1 are close to the Original results, with very similar generation and transmission investment costs. The Diversity 2 results have lower generation cost savings, which are partially a result of having a level of 2020 renewables which are very similar to Status Quo.

6.7 Diversity 3 has the most similar results to Status Quo. This model has the same amount of offshore wind in 2020 as Status Quo with slightly more onshore wind. The generation cost benefit is due to a later build of offshore wind capacity up to this point. The savings are therefore more marginal than for other transmission charging options.

		NPV 2014-2020 (£m real 2012)				
		Original	Diversity 1	Diversity 2	Diversity 3	HVDC (50% Option)
Benefit relative to Status Quo						
Power sector costs	Generation costs	958	931	349	223	952
	Transmission costs	137	143	73	5	135
	Constraint costs	-40	-34	-29	-32	-41
	Carbon costs	-104	-116	-45	-18	-102
	Decrease in power sector costs	**950**	**924**	**348**	**178**	**943**

Table 6.1 –Power sector costs relative to baseline period 2014-2020

Period 2021-2030

6.8 Table 6.2 shows the corresponding power sector cost results for the period 2021-2030.

6.9 The Original continues to show an overall benefit in power sector costs, albeit smaller than up to 2020. This is partially due to savings in transmission costs, due to continued lower offshore wind generation. This is offset somewhat by earlier reinforcement of the onshore network. There is also a saving in carbon costs, due to the earlier deployment and additional capacity of CCGT+CCS.

6.10 For the Original, the deployment of CCGT+CCS causes increased generation costs particularly in 2025 and 2026 which outweighs the other savings in the 2020-2025 period.

6.11 Of the four Alternatives, Original 50% HVDC is most similar to Original, with almost identical results. Diversity 1 shows the largest saving in power sector costs over this period, mainly due to lower renewables investment relative to the other models. Conversely, Diversity 2 is very close to the Status Quo results overall, but with different drivers. There is a saving in most years but the earlier build of CCGT+ CCS imposes a large cost in 2025 and 2026. The reason that Diversity 2 results show a net increase in cost (compared to a net decrease for the Original) is that the overall level of renewables is higher under Diversity 2 than Original.

6.12 Diversity 3 results show a large increase in generation costs that result partially from additional investment in new CCGT capacity, in addition to the features observed for Diversity 2.

		NPV 2021-2030 (£m real 2012)				
		Original	Diversity 1	Diversity 2	Diversity 3	HVDC (50% Option)
Benefit relative to Status Quo						
Power sector costs	Generation costs	-84	517	-579	-1,670	-116
	Transmission costs	214	407	236	86	205
	Constraint costs	33	43	-3	-9	37
	Carbon costs	257	58	304	249	274
	Decrease in power sector costs	**420**	**1,025**	**-41**	**-1,345**	**399**

Table 6.2 –Power sector costs relative to baseline period 2021-2030

7 Cost to Consumers

7.1 The changes in consumer bill include effects from BSUoS, losses, demand TNUoS and low carbon support. However they are dominated by changes in the wholesale cost of power (including capacity payments). Fuel and carbon prices are unchanged across the transmission charging options, and that the capacity mixes are similar overall. Therefore, the differences in wholesale cost are mainly a result of different capacity margins, with tighter margins leading to an uplift in power price.

7.2 The capacity margins for the six model runs are show in Figure 7.1 below. The Original and Alternatives follow a similar trend to each other. They are lower than the Status Quo in the period 2017-2020, and higher in the period 2024-2030. The higher margins in this later period are mainly a result of the additional CCGT+CCS build. As dispatchable generation, this contributes significantly to the de-rated capacity margin.

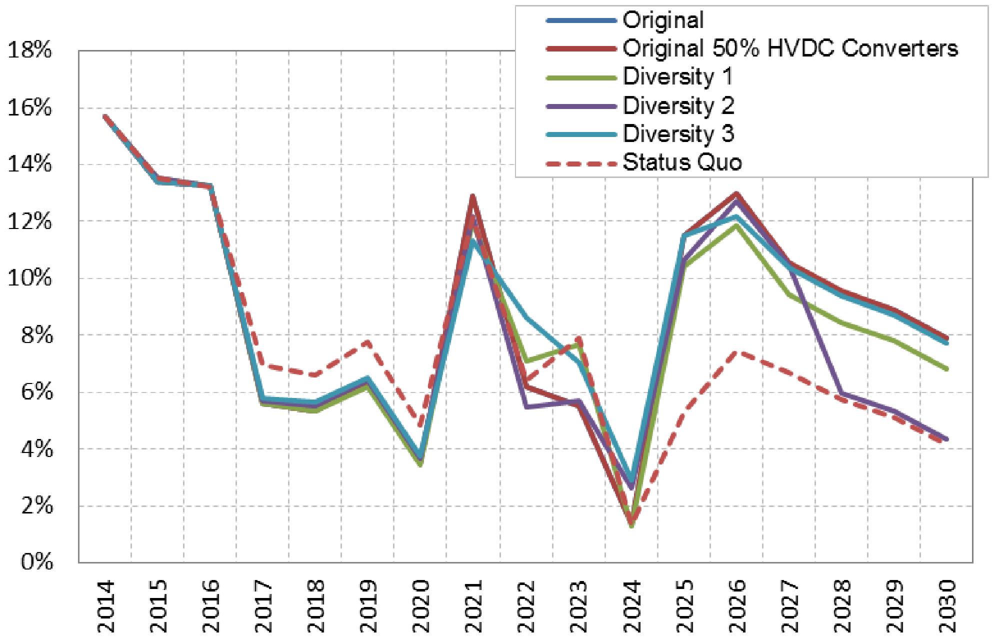

Figure 7.1–de-rated capacity margin

7.3 Figure 7.2 shows the change in the average domestic consumer bill under the Original and four Alternatives relative to Status Quo. Although underlying costs reduce, the consumer bills for the Original and Alternatives increase due to the wholesale price effect described above, and decrease after 2024.

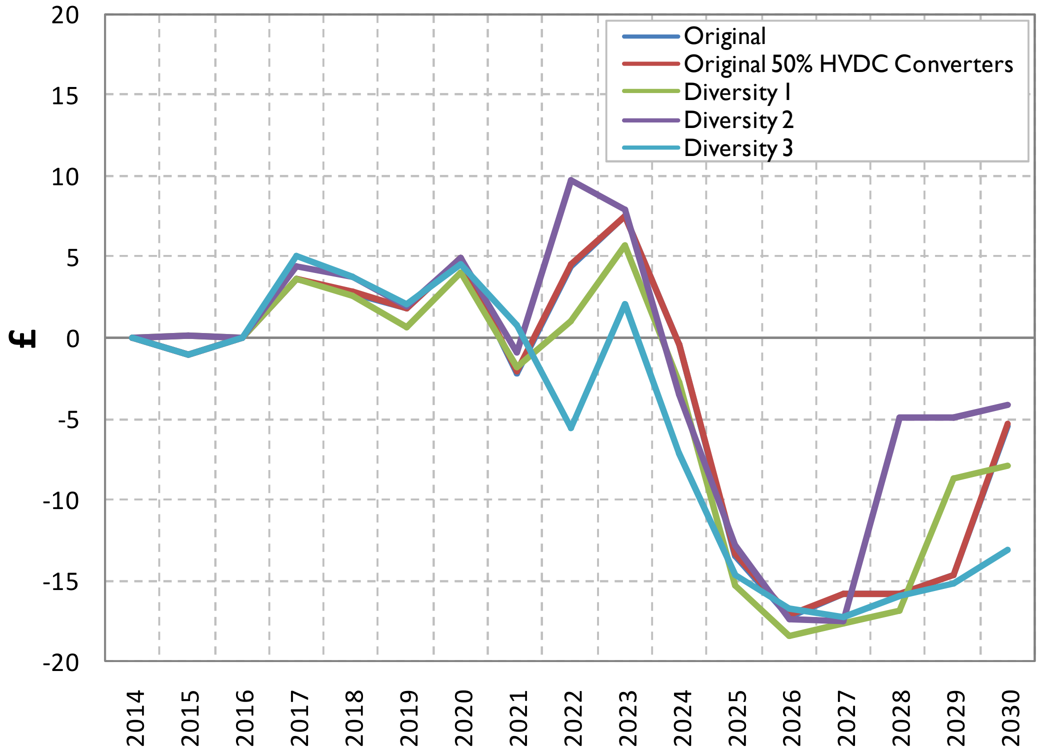

Figure 7.2 - Change in average consumer bill

8 50% sensitivity results

8.1 In this section the differences are discussed in the output results relating to transmission and generation investment in the models developed in May and listed in table 1.8. Also discussed are the relative impacts on power sector costs and consumer bills.

8.2 In summary it is observed that in the case of Diversity 2 there is a significant change from the alteration in HVDC converter cost calculation, whereas in Diversity 1 and 3 there is no significant change in results from the change to 50% HVDC converter costs. This suggests that the impact of the 50% HVDC Converter Cost options are marginal and may or may not have an impact on transmission investment decisions, depending on how marginal the economics of these decisions are.

Diversity 1 50% HVDC Model Results

8.3 The Diversity 1 50% model gives extremely similar results in generation and transmission decisions to Diversity 1 100% model with results almost identical up to and including 2023. After 2023 the differences are in a one year delay in the deployment of 500 MW of CCGT + CCS in South England & South Wales. There are no differences in retirements, and no other differences in new build.

8.4 In the same timeframe, the timing of two London (B14) / Estuary (B15) transmission reinforcements change, with a B14/15 reinforcement being brought forward from 2026 to 2024, and a B15 reinforcement delayed from 2025 to 2026.

8.5 The Cost Benefit Analysis shows a small additional saving in power sector costs(£69m) from the CCGT + CCS delay, and a small increase in consumer bills (-£180m) due to an increase in wholesale costs (-£218m) from the corresponding lower capacity margin, offset by a decrease in low carbon support of £41m. The scale of these differences is not significant. Therefore the same conclusions apply to Diversity 1 50% HVDC converter cost as apply to the Diversity 1 100% option.

		Diversity 1 - 100% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	931	517
	Transmission costs	143	407
	Constraint costs	-34	43
	Carbon costs	-116	58
	Decrease in power sector costs	**924**	**1,025**
Consumer bills	Wholesale costs (inc. capacity payments	-1,725	3,517
	BSUoS	-17	21
	Transmission losses	-42	32
	Demand TNUoS charges	135	274
	Low carbon support	930	667
	Decrease in consumer bills	**-719**	**4,511**

Table 8.1 –Power sector costs and consumer bill impacts for Diversity 1 – 100% HVDC relative to baseline

		Diversity 1 - 50% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	931	615
	Transmission costs	143	402
	Constraint costs	-34	43
	Carbon costs	-116	34
	Decrease in power sector costs	**924**	**1,094**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,740	3,300
	BSUoS	-17	21
	Transmission losses	-42	33
	Demand TNUoS charges	135	270
	Low carbon support	929	708
	Decrease in consumer bills	**-735**	**4,332**

Table 8.2 –Power sector costs and consumer bill impacts for Diversity 1 – 50% HVDC relative to baseline

Diversity 2 50% HVDC Model Results

8.6 In terms of generation build decisions, the main difference in results of this model from the Diversity 2 100% HVDC model is that the Diversity 2 50% HVDC model has 0.8 GW less of offshore wind capacity, all of which was located in the South. This difference is most likely due to marginally higher transmission tariffs in the South, due to an overall compression in tariffs.

8.7 In terms of retirement decisions, Diversity 2 50% retires 1.1 GW less CCGT capacity located in North England, but 0.95 GW more CCGT capacity located in South England and South Wales by 2030 (i.e. a total of 13.6 GW compared to 13.7 GW under Diversity 2). This is consistent with weaker locational signals under Diversity 2 50%.

8.8 The differences in transmission decisions are small. Diversity 2 50% advances some Estuary reinforcements by up to four years in the 2025 – 2030 period. This is outweighed by the savings in offshore transmission costs as a result of the reduction in offshore wind build.

8.9 Overall, the Diversity 2 50% HVDC Converter Cost model results are almost identical to Diversity 1 100% HVDC Converter Cost model in the period to 2020, and remains similar through to 2030. This suggests that the compression of tariffs through the reduction of HVDC expansion factors is having a similar impact from the compression though additional sharing with the Diversity 1 alternative.

8.10 The lower deployment of renewables under Diversity 2 50% increases the saving in power sector costs by £573m in the period to 2020, mainly due to savings in generation costs. Savings in transmission costs arise from lower deployment of offshore wind.

8.11 There is a benefit to consumer bills from the reduced cost of low carbon support. This is offset to some extent by the increase in wholesale costs as a result of a lower capacity margins in the period 2024-2027.

		Diversity 2 - 100% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	349	-579
	Transmission costs	73	236
	Constraint costs	-29	-3
	Carbon costs	-45	304
	Decrease in power sector costs	**348**	**-41**
Consumer bills	Wholesale costs (inc. capacity payments	-1,382	2,895
	BSUoS	-15	-1
	Transmission losses	-33	28
	Demand TNUoS charges	78	152
	Low carbon support	359	-464
	Decrease in consumer bills	**-992**	**2,609**

Table 8.3 –Power sector costs and consumer bill impacts for Diversity 2 – 100% HVDC relative to baseline

		Diversity 2 - 50% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	929	750
	Transmission costs	141	402
	Constraint costs	-34	43
	Carbon costs	-116	32
	Decrease in power sector costs	**921**	**1,226**
Consumer Bills	Wholesale costs (inc. capacity payments	-1,776	1,626
	BSUoS	-17	21
	Transmission losses	-43	32
	Demand TNUoS charges	135	270
	Low carbon support	929	1,212
	Decrease in consumer bills	**-771**	**3,161**

Table 8.4 –Power sector costs and consumer bill impacts for Diversity 2 – 50% HVDC relative to baseline

Diversity 3 50% HVDC Model Results

8.12 The Diversity 3 50% model is extremely similar in generation and transmission decisions to Diversity 3 100% model. The results are almost identical up to 2020. Beyond this there are differences in onshore wind build, with the Diversity 3 50% model deploying 190MW more island wind on Orkney by 2030. This is consistent with the reduction of island tariffs. There are no other differences in new build.

8.13 In terms of retirement decisions, Diversity 3 50% retires 0.9 GW less CCGT capacity located in Midland & North Wales in 2026. There are no other differences in retirements.

8.14 There are no differences in onshore transmission reinforcement decisions.

8.15 The Cost Benefit Analysis shows a very small saving in power sector costs (£19m), as a result of savings in generation and carbon costs, offset by the additional transmission cost of the island HVDC link relative to the Diversity 3 100% HVDC model. The results show an increase in consumer bills (-£1,059m) from the lower capacity margins after 2026 from the Diversity 3 100% HVDC model. The scale of these differences is not significant.

Therefore the same conclusions apply to Diversity 3 50% HVDC converter cost as apply to Diversity 3.

		Diversity 3 - 100% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	308	-762
	Transmission costs	28	324
	Constraint costs	-32	-9
	Carbon costs	-35	-128
	Decrease in power sector costs	**269**	**-576**
Consumer bills	Wholesale costs (inc. capacity payments)	-1,166	7,070
	BSUoS	-16	-5
	Transmission losses	-28	33
	Demand TNUoS charges	41	212
	Low carbon support	224	-1,210
	Decrease in consumer bills	**-944**	**6,102**

Table 8.5 –Power sector costs and consumer bill impacts for Diversity 3 – 100% HVDC relative to baseline

		Diversity 3 - 50% HVDC (£m real 2012)	
		NPV 2011-2020	NPV 2021-2030
Benefit relative to Status Quo			
Power sector costs	Generation costs	308	-723
	Transmission costs	28	255
	Constraint costs	-32	-9
	Carbon costs	-35	-79
	Decrease in power sector costs	**269**	**-557**
Consumer Bills	Wholesale costs (inc. capacity payments)	-1,180	5,900
	BSUoS	-16	-5
	Transmission losses	-28	17
	Demand TNUoS charges	41	173
	Low carbon support	224	-1,044
	Decrease in consumer bills	**-959**	**5,042**

Table 8.6 –Power sector costs and consumer bill impacts for Diversity 3 – 50% HVDC relative to baseline