Appendix 2.2: Modelling the impact of zonal transmission loss multipliers (report prepared by NERA Economic Consulting for the CMA)

NERA
ECONOMIC CONSULTING

Modelling the Impact of Zonal Transmission Loss Multipliers

Prepared for the CMA

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NERA Project Team

Sean Gammons
Richard Druce
Konrad Borkowski
Marissa Li

Imperial College Project Team

Goran Strbac
Christos Konstantinidis
Rodrigo Moreno

NERA Economic Consulting
Marble Arch House, 66 Seymour Street
London W1H 5BT
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com

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1. Introduction

NERA Economic Consulting (NERA) and Imperial College London (Imperial) have been commissioned by the Competition and Markets Authority (CMA) to estimate the costs and benefits of the CMA's proposed introduction of a zonal transmission losses scheme, made as part of its Provisional Findings and Notice of possible remedies for the Energy Market Investigation (EMI).

Currently, the costs of transmission losses are socialised amongst generators and consumers, in the sense that there is no locational variation in transmission losses across different parts of the country. The main purpose of this work is to estimate the costs and benefits of moving from this system of socialised transmission losses to an alternative scheme in which the allocation of transmission losses to generators and consumers varies by location according to estimates of the marginal change in losses caused by marginal changes in generation and/or consumption at different points in the system.

In contrast to our previous work on a similar topic prepared for RWE,[1] an objective of this study is to examine the sensitivity of our estimated costs and benefits to changes in fundamentals assumptions, principally in respect of fuel and carbon prices.

The scope of this report is as follows:

- Chapter 2 sets out the method we followed in order to assess the costs and benefits of a zonal transmission losses scheme;
- Chapter 3 summarises our modelling assumptions and sets out key features of the scenarios we examined to test the sensitivity of the impact of a zonal transmission losses scheme to changes in underlying assumptions on market fundamentals;
- Chapter 4 describes our modelling results across the scenarios we examined, including the estimated welfare effects of adopting a system of locational transmission losses; and
- Chapter 5 concludes.

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[1] NERA Economic Consulting and Imperial College London (11 May 2015), The Welfare Effects of Locational Transmission Loss Factors in the British Wholesale Electricity Market, Prepared for RWE.

2. Methodology

2.1. Our Modelling Tools

We use two key modelling tools for this assignment, which we describe in more detail below. Both models have been applied in the course of numerous previous studies, both separately and together. Notably, we use broadly the same modelling framework as we applied in our recent study of the impact of zonal transmission losses for RWE.[2]

Both the models described below use common assumptions on the mix of existing generation, new generation expansions, the cost of new generation investment, demand, generation marginal costs (fuel, CO_2 and variable operating and maintenance costs), and so on.

2.1.1. NERA's "Aurora" wholesale market model

NERA's wholesale market model is a fundamentals model of the wholesale electricity market in Great Britain, which schedules and despatches generation, and can also select optimal generation investments and closures depending on the scenario. It is implemented using the "Aurora" power market modelling software platform (vended by EPIS Inc). This model schedules and despatches generators using a Mixed Integer Linear Program (or "MIP") that minimises generation costs subject to constraints, such as the need to ensure demand is met, that sufficient spinning reserves are scheduled, and so on. In essence, this model seeks to mimic a process of competition between generators.

Aurora can also optimise the timing and location of new thermal generation investments and closures such that those generators who can enter the market profitably will do so, and those who do not cover their costs (including a normal return on capital) exit the market. Locational investment incentives in Aurora mainly depend on locational differences in generation TNUOS charges that are factored into the model.

The model we propose to use for this assignment optimises flows across interconnectors to neighbouring markets:

- We have a fully endogenous treatment of the Irish market, with all plants scheduled and dispatched in the same way as described above for Great Britain; and
- We adopt a simplified treatment of the continental European interconnectors, assuming that import and export flows are despatched according to an exogenously defined hourly wholesale price curve for neighbouring continental European markets (i.e., assuming GB is a price-taker vis-à-vis these markets).

Aurora defines energy market prices according to the marginal variable cost of the marginal generator required to meet demand in each hour, plus an uplift function that ensures those generators in the least cost despatch schedule can recover their unit commitment costs, such as the costs of starting-up their plant. Likewise, Aurora defines a capacity market price

[2] NERA Economic Consulting and Imperial College London (11 May 2015), The Welfare Effects of Locational Transmission Loss Factors in the British Wholesale Electricity Market, Prepared for RWE.

according to the marginal capacity cost of the marginal generator required to meet the capacity target in each year, where the marginal capacity cost is defined net of energy market profits.

Aurora is a chronological model and can be run for every hour of the year, but it can also be run in a mode that samples hours to economise on run time. When modelling the impact on plant despatch from the introduction of transmission loss multipliers, we run the model for every single hour of the modelling horizon. However, to the extent we use Aurora to select optimal generation investments, we run it using a sample of hours to ensure the model solves within a reasonable length of time. Usually, we sample:

- Every second hour of the day,
- On Monday, Wednesday, Friday and Sunday;
- In the first and third weeks of each calendar month.

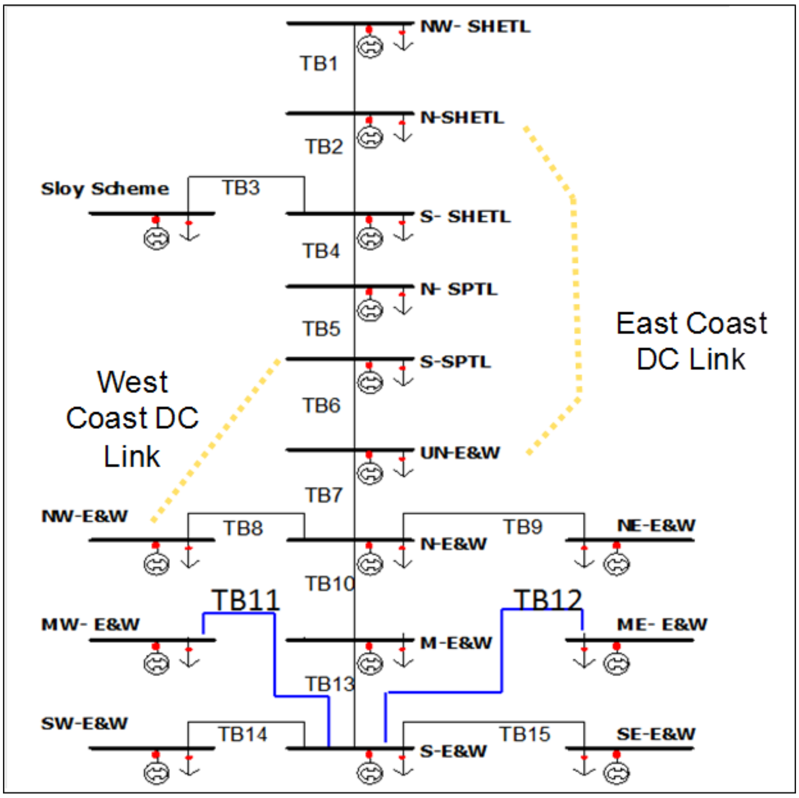
2.1.2. Imperial’s Dynamic Transmission Investment Model

Imperial’s Dynamic Transmission Investment Model (DTIM) represents conditions on the British electricity transmission system. DTIM was developed by Imperial College/SEDG for the purpose of supporting optimal transmission investment decisions on the transmission system in Great Britain. DTIM can balance the costs of network constraints and transmission losses against the costs of network reinforcement, minimising the overall cost of power system operation and expansion over a given duration (e.g., the next twenty years). Throughout the optimization period the model determines when, where and how much to invest using data inputs including a demand forecast, current and future fuel costs, bids and offer prices, evolution of installed generation capacity, the location and quantity of new wind capacity, transmission and generation maintenance plans, etc.

DTIM uses a 16-zone, 15-boundary radial network to represent the GB transmission system, as shown in Figure 2.1. Each node represents a GB zone, and each branch represents a boundary.[3] In order to reflect the need for the HVDC bootstraps, DTIM includes constraints on maximum boundary capacities, the most important of which is the maximum capacity of 4.4GW on the Cheviot boundary (i.e., any further increase in Scotland –England transmission capacity can be delivered only through the HVDC links in DTIM, which is broadly consistent with published evidence from GB transmission owners).

[3] The network was developed by Imperial College and has been used extensively in the past for supporting the Transmission Access Review (TAR), the fundamental review of the SQSS, and by National Grid to validate a CBA exercise performed for the ENSG. We have also included the Western and Eastern DC links in the model, and allowed DTIM to optimise the timing and capacity of these “bootstrap” investments, save for the first Western bootstrap, which we assume will come online for sure.

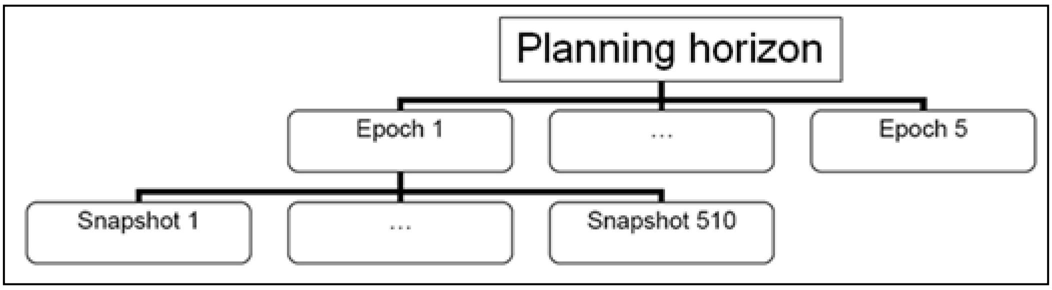
Figure 2.1
DTIM Radial Network



Source: Imperial

We run the DTIM model for the next 20 years (2015-35), grouping these years into five "epochs" lasting 4 years each. Investment in transmission capacity takes place at the beginning of each epoch. Throughout an epoch, generation capacity is assumed to be static, and generation fuel costs and availabilities can be varied seasonally. Each epoch consists of 510 representative snapshots, designed to represent a range of fundamental demand and supply conditions.

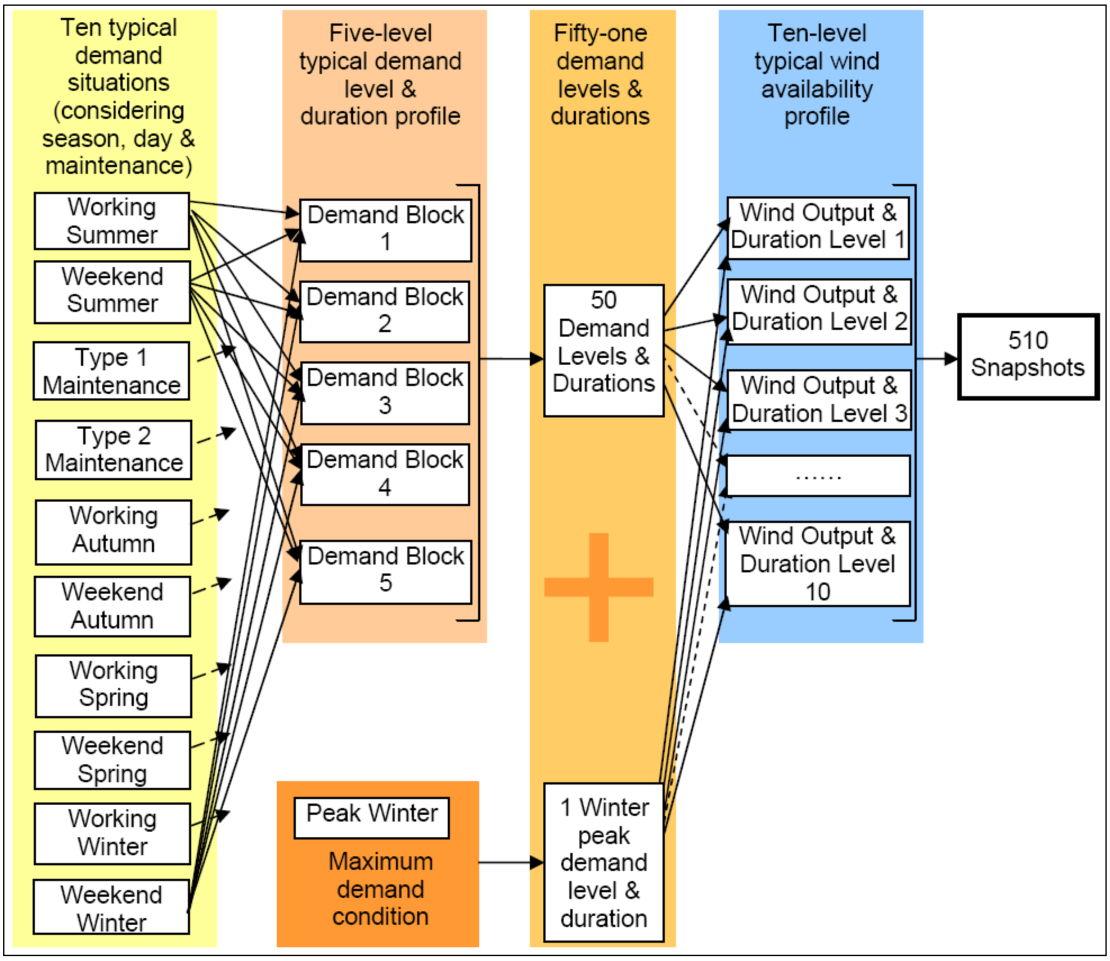
Figure 2.2
DTIM Epochs



Source: Imperial College

The 510 snapshots are obtained by combining 51 demand levels with 10 wind output levels. Of the 51 demand levels (each with a duration specified within the model), one of them represents the level of winter peak demand, and the other 50 are derived from 5 daily demand blocks that apply on 10 typical days. The 10 typical days are working days and weekends for winter, spring, summer, autumn and boundary maintenance seasons respectively. The demand levels are adjusted to take into account any intermittent embedded generation including PV and hydro. Figure 2.3 summarises this process.

Figure 2.3
DTIM Snapshot Definitions



Source: Imperial

2.2. Modelling Procedure

2.2.1. Basic step-by-step modelling process

For a given set of fundamentals assumptions, we adopt the following modelling procedure in applying Aurora and DTIM to estimate the impact of zonal transmission loss factors:

1. We begin by running NERA's Aurora model (described further below) to optimise the generation mix. Hence, Aurora selects the optimal timing and quantity of new investment, and optimise the timing of plant exits:

   – Aurora's ability to invest in new plant and close existing plant is constrained to some degree by our modelling assumptions. For instance, we form exogenous assumptions on the penetration and mix of low carbon plant, and we impose constraints on the timing of some plant closures, such as due to the commitments owners of coal plant have made to retire in order to comply with emissions control regulations.

2. Given the forecast of the generation mix emerging from Aurora, we pass data on plant capacities and locations to DTIM. Aside from these results from the first model run, we also populate DTIM with the same demand and generation marginal cost assumptions as we use in Aurora.
3. We then run DTIM to build the transmission network and estimate zonal transmission loss factors over the entire modelling horizon, which we then pass back to the Aurora model. The process for computing loss factors is discussed in more detail below in Sections 2.2.3 and 2.2.4.
4. Taking the results from steps (1), (2) and (3), we then run Aurora for a second time to estimate the change in despatch due to applying zonal transmission loss factors, holding all investment decisions constant and use the results for CBA calculations. Specifically, we run Aurora twice at this step, once with zonal and once with uniform national loss factors and compare despatch, generation costs, etc between the two runs (see Section 2.2.5 below)

2.2.2. The need for iteration in forming locational assumptions for new plant

As described above, Step 2 of our modelling procedure involves placing generation plant around the transmission system before passing the data on plant locations and capacities to DTIM. For existing transmission-connected plants, which are all identified individually in Aurora, the plant locations are known and fixed. We therefore only need to form assumptions on the location of new plants within Aurora.

Ideally, we would model optimal plant location as a function of a range of factors, such as TNUoS charges, NTS Exit charges, land costs and so on. Of these, TNUoS depend on network topography and the locational spread of generation, which also depend on TNUoS, and hence some iteration would also ideally be required to identify equilibrium investments. Accordingly, recent work done by NERA and Imperial during Project TransmiT involved an iterative modelling procedure between DTIM (to build the network), a load flow model of the transmission system (to forecast TNUoS charges) and market models (to estimate changes in plant location) and thus to assess the welfare effects of TNUoS reform.

However, iterating in this way is extremely time consuming, and was not feasible over the CMA's timeframe. We also judged that it is of secondary importance for considering the impact of zonal losses, as cost differences due to locational losses are small compared to the cost differences due to locational TNUOS charges and other locational factors.[4] We therefore optimised the location of new plant based on the TNUoS charges forecast in the NERA and Imperial modelling study conducted during Project TransmiT,[5] as well as other locational cost assumptions used in this study. We consider this approach to be reasonable on the basis that the locational investment decisions emerging from this study were based on a process of iteration between Aurora and DTIM.

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4 We may test this hypothesis by allowing Aurora to select optimal generation investments with and without the application of zonal loss factors. If the change in investments (entry and exit decisions) is marginal, we will assume that this assumption that there is no impact on optimal investments is reasonable for the purposes of this study.

5 NERA Economic Consulting and Imperial College London (27 May 2014), Project TransmiT: Updated Comparison of the WACM 2 and Status Quo Charging Models, Prepared for RWE npower.

2.2.3. Computing marginal loss factors for representative levels of demand and wind output

As described above, Step 3 of our modelling procedure involves using DTIM to estimate zonal transmission loss factors. DTIM despatches generators and selects optimal transmission reinforcements in a way that minimises the cost of the power system, making a least cost trade-off between constraints, losses and investments to reinforce the grid. It does this by examining conditions on the transmission system in a number of different "snapshots" (within each season and 4-year "epoch") designed to capture different levels of wind output and demand.

The first leg of Step 3 is to use DTIM to estimate the marginal change in total losses that results from increasing net injections (= generation output, less demand) by one MWh in a particular zone, and at the same time reducing net injections by one MWh in a reference zone. We perform this calculation for each zone, wind/demand/seasonal snapshot and epoch.

2.2.4. Converting DTIM loss factors into zonal transmission loss multipliers for use in Aurora

The second leg of Step 3 is to convert these zonal loss factors produced by DTIM for each "snapshot" into zonal transmission TLMs for use in Aurora in every single hour of the modelling horizon.

Rather than representing how conditions change across a number of "snapshots" like the approach implemented in DTIM, Aurora defines demand and wind production with an hourly "shape" based on historic market data. We shift these "shapes" upwards over time as wind capacity and demand rise.

This difference in approach requires that we map the DTIM marginal loss factors (produced using DTIM for discrete levels of demand and wind production) onto a demand curve that varies per hour. We perform this mapping using a regression procedure. Essentially, for every season, zone and epoch, we estimate a regression equation based on the DTIM results that predicts marginal loss factors as a function of demand and wind production. We then use this regression equation to predict hourly loss factors for each zone based on the assumed demand and wind production in each hour in Aurora.

This process involves estimating 320 regressions in total (= 16 zones x 5 epochs x 4 seasons) using the following specification:

$$Loss\ Factor = Constant + a_1 \times Wind + a_2 \times Wind^2 + a_3 \times Demand + a_4 \times Demand^2 + a_5 \times (Wind \times Demand) + Error$$

- The term "Loss Factor" represents the marginal loss factor;
- "Wind" represents the level of wind production as a load factor ranging from 0 to 1; and
- "Demand" is power demand on the British system in MW, net of production from embedded generation;
- The "Error" term represents the variation in loss factors not explained by the other parts of the equation.

We estimated the a_1 to a_5 terms using a weighted least squares technique, placing most weight on those DTIM snapshots that are intended to represent the highest number of hours in the year. Details of the regression technique are explained in more detail in Appendix A.

In essence, this regression equation maps the DTIM estimates of the underlying marginal change in losses from changes in injection by zone onto an hourly demand and wind production shape. The next step before using these data in Aurora is to convert these estimates into the transmission loss multipliers that would apply if the CMA were to implement a zonal transmission loss mechanism.

We wil do this by (1) averaging the hourly series predicted by the above regression over each season, which assumes that zonal loss factors would remain constant across each season, and (2) applying the assumed G/D split (currently 45/55) that allocates marginal losses between generators and demand consumers. This approach is intended to mimic, albeit approximately, the types of zonal loss factors prescribed by BSC Mod 229, under which locational variation in generators' and consumers' transmission loss factors would be set based on seasonal averages.

2.2.5. Market modelling and conducting a CBA

The final stage of our modelling procedure is then to use the modelling loss factors in the Aurora model to estimate costs and benefits. By running Aurora to despatch plant both with and without locational variation in loss factors, we can perform a CBA of the introduction of zonal loss factors. Each Aurora run provides forecasts of plant despatch patterns, generation costs (fuel, CO2, variable and fixed O&M) and power prices (capacity and energy). We take the change in constraint costs from DTIM, as the Aurora model does not account for transmission constraints within GB.

We estimate the change in transmission losses from the application of zonal TLMs by multiplying the change in despatch by plant by the marginal loss factors estimated using DTIM. This approach is an approximation because it assumes the losses caused by an individual plant are a linear function of its output, but we consider this a reasonable assumption on the basis that changes in despatch patterns are likely to be small, making the assumption of a locally linear loss function reasonable. And to the extent this assumption is an approximation, it could equally be a slight under or over statement, so this approach does not introduce bias into our results.

3. Modelling Assumptions and Scenario Definition

This chapter describes the basic data and assumptions that we use across all our modelling scenarios, and describes the basis for the scenarios we run in our models. The data freeze date we adopted for this modelling was 31 October 2015.

3.1. Data and Assumptions on the Existing Generation Fleet

3.1.1. Capacity data for existing plants

For our modelling, the first basic input we require is a list of existing plants and their capacities. We use up-to-date capacity data for the existing generation fleet from two sources. As a starting point, we take projections of installed capacities of existing plants and new plants under construction from Platts Powervision. Due to PowerVision overstating the true sent-out capacity of the plants in some cases, we calibrate these capacities to National Grid's July 2015 Transmission Entry Capacity (TEC), wherever the registered TEC is lower than the capacity stated in Powervision.

3.1.2. Treatment of existing coal plants

We then need to form assumptions on when coal plants will retire. Starting with the existing coal fleet, we assume that around 12 GW of coal capacity will have shut by the end of 2015 under the Large Combustion Plant Directive (LCPD), based on published announcements.[7] In relation to IED compliance, as the decisions of individuals plants were not published at the time of developing our modelling scenarios, we used the results of the first T-4 CPM auction to guide our assumptions on IED opt-in/opt-out decisions for coal plants. We assume the following in our modelling:

- Coal units which successfully secured refurbishment contracts at the T-4 auction fit SCR technology and therefore "opt-in" to the IED from 2016 onwards; and
- All other coal units "opt-out" of the IED and therefore run with 17,500-hour operating constraints until the end of 2023 when they are forced to close, or until the end of their maximum operating life if sooner.

We further assume that all unabated coal plants are shut by 2025, in line with the recent government policy announcement.[8]

In forming these assumptions, we consider that we have tended to be conservative in estimating the effect of the policy to introduce zonal transmission loss factors. By constraining the operating lives and operating hours of coal plants, we give the model limited scope to adjust despatch of these plants. If we had allowed the model more discretion to adjust despatch in response to changes in loss factors, we may have found a greater improvement in welfare from the policy.

In relation to Longannet, Scottish Power has announced its intention to close the plant in 2016. However, given the importance of north-south power flows in determining loss factors,

7 PowerVision and TEC register.

8 DECC: Government announces plans to close coal power stations by 2025, 18 November 2015.

we acknowledge that this decision could be changed if the economics of the plant improved under one or more of the particular modelling scenarios we have run (see more details below). In particular, we use the following assumptions in each of the fundamental cases we define below:

- Reference Case: we assume Longannet closes in 2016 as announced by Scottish Power;
- High Case (designed to be one in which coal is least competitive relative to gas): we assume Longannet closes in 2016; and
- Low Case (designed to be one in which coal is most competitive relative to gas): we assume Longannet has the option of remaining online until 2023, but we allow the model to close it earlier if it appears uneconomic for it to remain open.

3.1.3. Treatment of other thermal plants

In addition to coal plants, our modelling also takes into account assumptions on the treatment of other existing thermal plants. In relation to programmed expansions, we base our assumptions on the results of the first T-4 auction.[9] In particular, we factor into our modelling the 2.6 GW of Capacity Agreements awarded to existing plants in the first T-4 auction as follows:

- incorporate 1.6 GW of generic new entrant CCGT, to represent Trafford power station; and
- incorporate 965 MW of generic new entrant OCGT (i.e. peaking capacity) to represent the remaining new build capacity awarded Capacity Agreements in the first T-4 auction, made up of small embedded generators.[10]

Moreover, we assume that all existing plants that were awarded contracts in the T-4 auction stay online for the full length of their contract. Aside from these constraints, closure decisions of existing fossil fuel plant are made endogenously within our Aurora model, based on the economics of each plant.

Within our model, drivers of whether existing plant can earn sufficient revenues from the sale of energy and capacity to remain on the system are their assumed fixed O&M costs, which we take from Parsons Brinckerhoff[11], and their TNUoS charges, which we take from the latest forecasts produced by NERA and Imperial produced during the Project TransmiT process.[12]

For existing nuclear plants, we assume existing plants will decommission following the path of total energy production from these technologies outlined in the UEEP (2015). Because the UEEP projections do not provide unit level data, we assume all plants to achieve 1-year life

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[9] The results of the second auction held at the end of 2015 became available too late for us to account for the results in our modelling.

[10] Of the 965 MW of new build OCGT capacity, 735 MW has a 15-year contract, 32 MW has a 14-year contract and 198MW has a 1-year contract.

[11] Parsons Brinckerhoff: Electricity Generation Cost Model – 2013 Update of Non-Renewable Technologies, April 2013.

[12] NERA Economic Consulting and Imperial College London, Project TransmiT: Updated Comparison of the WACM 2 and Status Quo Charging Models: Prepared for RWE, 27 May 2014.

extensions compared to the currently announced closure schedule,[13] in order to match the UEEP projections as closely as possible.

3.2. Electricity Demand Growth Assumptions

The starting point for our demand forecast is an hourly profile of historic demand from 2014. From 2015 onwards, we inflate this demand shape by the annual forecast demand growth rates implied by the "central scenario" from DECC's 2015 Updated Energy and Emissions Projections (UEEP). This calculation derives our "underlying" forecast of energy and peak demand.

We then add to this "underlying" demand forecast a forecast of the demand that will come from electric vehicles (EVs) and heat pumps (HPs) from National Grid's "Gone Green" scenario from the 2015 Future Energy Scenarios publication. Moreover, we shape the consumption from EVs and HPs across all hours of the year based on consumption patterns provided by Imperial College to derive their respective contribution to peak demand.

As our demand projection is based on actual consumption profiles, we do not make explicit assumptions about elasticity. These consumption profiles will already account for some elasticity as demand/prices rise and fall.

Regarding the location of demand, Imperial uses data from National Grid as the basis for distributing demand around the GB transmission system in DTIM.

3.3. Assumptions on Future Generation Investment

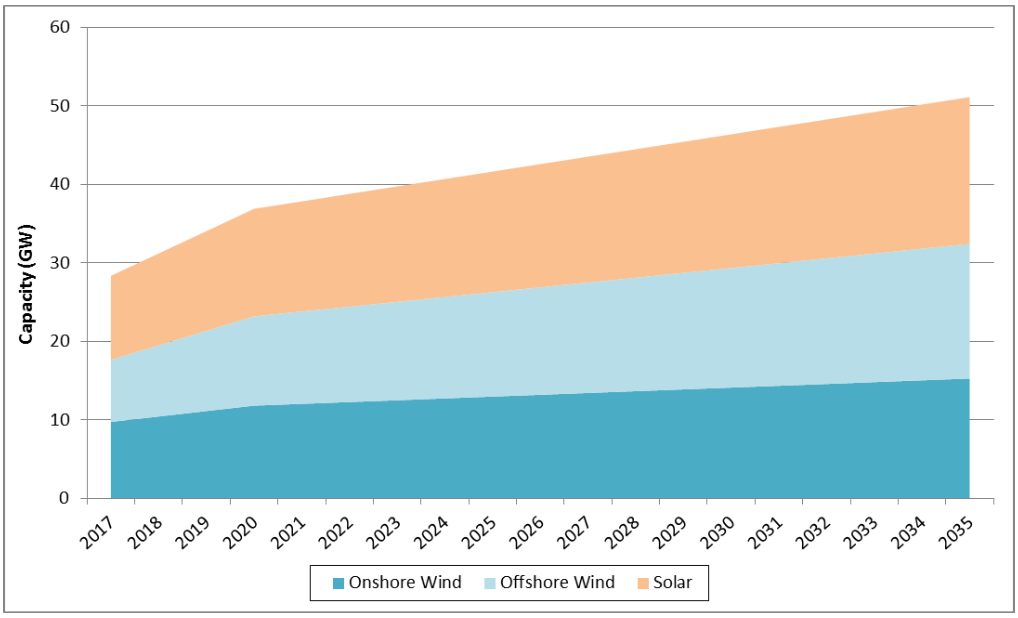
3.3.1. Future investments in renewables

The future mix and penetration of low carbon generation technologies depends primarily on future government policy on which technologies to support through the various subsidy mechanisms it uses to remunerate investments in these technologies. We therefore form assumptions that are intended broadly to reflect current government policy, as represented in DECC's 2015 UEEP.

For renewables, we use the current capacity mix from the 2015 Digest of UK Energy Statistics (DUKES) as a starting point, to which we apply a growth rate of each renewable technology based on an analysis of the project pipeline between 2015 and 2020 from the RESTATS (January 2014) database. From 2020 onwards, we assume that growth in total renewables capacity matches the UEEP (2015), which is achieved through expansions in onshore wind, offshore wind and solar in proportion to their average growth between 2015 and 2020. As a result, and as Figure 3.1 shows, renewables penetration is 11.5 GW for onshore/offshore wind and 13.7 GW for solar by 2020, and by 2030 the capacities reach 14.1 GW, 15.2 GW and 17 GW for onshore wind, offshore wind and solar, respectively.

[13] Source: Nuclear Industry Association website.

Figure 3.1
Assumed Investment in Renewable Generation Capacity by Technology



Source: DUKES,RESTATS and UEEP

Having defined assumptions on the amount of each renewable technology that will be installed, we then make assumptions on where this capacity will be deployed.

- For onshore and offshore wind, we place wind projects around the transmission system based on an optimisation that minimises the cost of deployment for these technologies. To do this, we take as given the energy requirement from onshore and offshore wind in each year of the modelling horizon. Then, using a cost minimisation algorithm, we use a model to select which projects get developed, making an optimal trade-off between variations in load factors, TNUoS, development costs, and so on. It also accounts for factors such as regional resource caps, variation in offshore costs by seabed depths, etc. We developed the basic functionality of this tool during our previous modelling work performed in the course of Project TransmiT.[14]
- We assume solar investment is distributed across the country based on the location of existing capacity.

3.3.2. New nuclear and CCS investments

We assume 3.2 GW of new capacity will come online in 2025.[15] Thereafter, we assume the expansion of nuclear capacity at the rate reported in UEEP, namely 9 GW by 2028 and 14.3 GW by 2035. We also make assumptions on the likely order of nuclear commissioning, using the following sequencing of projects: Hinkley Point, Sizewell, Oldbury, Wylfa, Sellafield and finally Broadwell.

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14 NERA Economic Consulting and Imperial College London, Project TransmiT: Updated Comparison of the WACM 2 and Status Quo Charging Models: Prepared for RWE, 27 May 2014, Section 2.3.

15 We assume this is the earliest feasible online date for the first new unit at Hinkley Point.

We also make assumptions regarding investments in CCS technology. In particular, we assume no new CCS capacity in the short-term, reflecting recent government decision to withdraw funding for CCS demonstration.[16] From 2020 onwards, we assume growth in CCS capacity at the rate reported in UEEP (2015), namely 3.5 GW of total CCS capacity by 2030 and 8 GW by 2035. Additionally, we assume:

- CCS projects are split equally between coal and gas plants;
- CCS projects are split evenly between the north and south, across four transmission zones close to the North Sea oil and gas infrastructure that could be reused for CO2 transportation. These zones are approximately Southern Scotland, Northwest England, East Midlands and the South East[17];
- The order of CCS project commissioning across coal and gas and between transmission zone are randomised, and fixed across scenarios; and
- Our model despatches CCS plants on the basis of marginal costs, such that any CCS support does not distort efficient despatch overall.

3.3.3. Investments in new conventional generation

Expansion of CCGT and OCGT capacity is performed endogenously by our Aurora model (see Section 4.1.1). Similar to our approach to modelling wind deployment, the model optimises the deployment and location of new CCGT and OCGT plants in order to minimise cost, subject to a range of assumed costs and constraints. These include TNUoS charges, NTS exit charges, land costs and exogenous constraints on zonal building limits. These locational assumptions for existing thermal plant are unchanged from our previous work conducted in the course of Project TransmiT.[18]

Our new entrant cost assumptions for thermal generation technologies are summarised in Table 3.1 below.

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16 London Stock Exchange: HM Government Statement to Markets Regarding Carbon Capture and Storage Competition, 25 November 2015.

17 Transmission zones 6, 9, 13 and 17 in National Grid: The Statement of Use of System Charges, April 2012.

18 NERA Economic Consulting and Imperial College London, Project TransmiT: Updated Comparison of the WACM 2 and Status Quo Charging Models: Prepared for RWE, 27 May 2014.

Table 3.1
Summary of Other Key Modelling Assumptions

Assumptions	Details of Our Approach
New entrant costs	• For new entrants, we adopt generic cost and performance assumptions based on publically available sources: – Electricity Generation Cost Model 2013 Update of Non-Renewable Technologies, PB Power – Electricity Generation Cost Model - 2012 Update of Non Renewable Technologies, Mott MacDonald's UK Electricity Generation Costs Update – 2011. – We take the average of the capital and O&M costs from these publications, and adjust the capex estimates for IDC using specific WACC assumptions. • The new entrant WACC assumption is a NERA estimate, and is set at 6.45% real pre-tax.
TNUoS charges	• We take the forecast of WACM2 TNUoS charges from Project TransmiT. • As this forecast runs to 2030, we assume TNUoS charges remain constant in real terms thereafter.

3.4. Transmission System Assumptions

3.4.1. Interconnection expansion

Our approach to modelling interconnection differs across the Irish and Continental European[19] markets. For the former, we assume that all plant in Ireland are scheduled and despatched endogenously by the model in the same way as in Great Britain. In comparison, interconnectors in Continental European are treated in a much simpler manner. Specifically, we assume that import and export flows are despatched according to an exogenously defined wholesale price curve for neighbouring markets and moreover assume that:

- Great Britain is a price-taker vis-à-vis these markets; and
- The European price is in turn based on the marginal cost of gas-fired generation, with daily shape reflecting the volatility in gas market prices across the year.

In relation to the planned expansions in interconnection, we use the capacities and commissioning dates from National Grid's "Interconnectors" publication,[20] which envisages the following expansions with Great Britain:

- 1,000 MW with Belgium from 2019 onwards;
- 1,000 MW with France from 2020 onwards;

19 Consisting of Belgium, France, Norway and the Netherlands.

20 National Grid: Interconnectors, May 2014.

- 1,400 MW with Norway from 2020 onwards; and
- 1,000 MW with Ireland from 2020 onwards.

3.4.2. Transmission system boundary capacities

For the modelling conducted in DTIM (see Section 2.1.2), we take existing transmission boundary capacities, based on the capacity currently installed on the GB transmission system (see Table 3.2 below). For each boundary, the model requires data on the thickness, seasonal rating, initial capacity and transmission expansion costs. The expansion cost is a piece-wise linear function which consists of up to 5 sections. The ratings of boundaries are scaled by different factors corresponding to five seasons (Summer, Autumn, Winter, Spring and Maintenance) and windy/non-windy conditions.

Table 3.2
DTIM Transmission Boundary Characteristics

Transmission corridor	2010 Transfer Capability (MW)	Boundary Thickness (Distance, km)
SHETL- North West	400	60
SHETL- North to South	1600	100
SHETL- Sloy Export	210	50
SHETL – SPT	1550	120
SPT- North to South	2618	35
SPT – NGET	2200	150
NGET - Upper North – North	3573	150
NGET - North Wales	3000	79
NGET- Humber	5500	40
NGET- North to Midlands	10000	93
NGET- South Wales	3500	75
NGET- East Anglia	2800	80
NGET- Midlands to South	10000	155
NGET- South West	3477	195
NGET- Estuary	5000	60
HVDC East Coast	0	300
HVDC West Coast	0	250

Source: Imperial College

We assume the first HVDC bootstrap will be commissioned, on the basis that it is already under construction, but allow the model to build other transmission investments[21] endogenously. The only constraint on new boundary reinforcement that we impose is to limit the capacity of the onshore grid on the SPT-NGET boundary to 4.4GW.

Given the simplified boundary structure of the model, the cost of reinforcing each boundary depends on the assumed unit cost of transmission (in £/MW/km/yr), which is multiplied by the assumed thickness of each boundary (in km).

[21] In particular, note we do not assume the second (or any subsequent) HVDC investments will take place.

3.4.3. Transmission reinforcement costs

We assume a uniform cost of reinforcement across the AC network of £60/MW/km/yr for all onshore circuits. In reality, we recognise that a diverse range of reinforcement options exists (e.g. overhead lines vs. underground cables, reinforcements at different voltage levels, building new substations), the cost of which will vary. However, we assumed a uniform reinforcement cost of £60/MW/km/yr on the basis that it is a reasonable approximation of the average cost of adding boundary capacity to the onshore network. This is in line with National Grid estimates, set out in the recent review into the NETS SQSS, which use three alternative methods to derive a high-level generic cost of reinforcement: [22]

- *'Ideal' pricing, based on idealised reinforcements of overhead line.* This method yielded a reinforcement cost of £58 /MW/km/yr;
- *Actual pricing, based on actual planned examples of network expansion outlined in a 2009 Electricity Network Strategy Group (ENSG) report.* National Grid converted ENSG estimates of total project costs into £/MW/km/yr reinforcement costs, which ranged from £100 to £240/MW/km/yr; and
- *Average pricing, based on TO revenues and installed capacity.* This method yielded reinforcement prices of £32, £58 and £41/MW/km/yr, for SHETL, SPT and NGET respectively.

In our modelling, the only type of investment to which we apply a different cost assumption is the offshore HVDC bootstraps, on the basis that these technologies are more expensive than conventional AC reinforcements. For the offshore bootstraps, we assume a reinforcement cost of £160/MW/km/yr.[23]

3.4.4. Bid-offer spreads

The costs of constraining generators down in one part of the country and constraining them up in another part of the country depends on the bids and offers they submit to the balancing mechanism. We apply the bid/offer prices assumed in the Redpoint modelling conducted as part of the Project TransmiT process.[24]

3.5. Proposed Scenarios for Long-term Commodity Costs

Following discussions with the CMA, we examine three sensitivities around the difference between the marginal costs of coal and gas generation.

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[22] National Grid April 2011, *NETS SQSS Amendment Report GSR009 Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation,* Appendix 5, pages 58-59

[23] The assumptions used by National Grid regarding the cost of the western HVDC link in the Transport and Tariff Model (£113/MW/km/yr and length of 370km = £41,810/MW/yr) results in a similar overall cost to our assumption (£160/MW/km/yr and a length of 250km = £40,000/MW/yr).

[24] Redpoint Energy, Modelling the Impact of Transmission Charging Options, December 2011, Table 30.

3.5.1. Commodity price projections

We have examined a range of alternative scenarios on long-term coal, gas and CO_2 prices to project the marginal cost of generation using these alternative sources over the period to 2030. Across all scenarios we have examined, we take historic commodity prices up to 31 October 2015, then use forward prices quoted on this date until the end of 2015. From then, we use alternative long-term price forecasts from third party sources.

As we want to examine a range of scenarios on the competitiveness of coal and gas, we obtained long-term forecasts of coal, gas and EU ETS CO_2 prices from two alternative third party sources, the IEA's World Energy Outlook (2015)[25] and from DECC (2015)[26].

The long-term projections of energy trends in the WEO are based on three scenarios, which differ in their assumptions regarding the evolution of international energy policies: the Current Policies Scenario, New Policies Scenario and the 450 Scenario. These scenarios vary mainly according to the evolution of government policy to combat climate change, with the New Policies Scenario assumed to be the central case in the WEO.[27]

DECC also produces coal, gas and EU ETS CO_2 price scenarios, with its scenarios characterised as Low, Central and High. As far as we know, DECC provides no explanation of the underlying assumptions behind these scenarios. [28]

Separately, we also define scenarios for the evolution of the UK Carbon Price Support (CPS) rate, measured at £/tCO_2, which tops up the EU ETS price and makes British power stations less competitive than those in neighbouring markets. In its 2014 annual budget, the government announced a capping of the CPS at its 2016/17 rate of £18/tCO_2 until 2019/20. The government will review "*whether a continued cap on the Carbon Price Support rate might be necessary*"[29] in 2019/20 once the trajectory of the EU ETS price becomes clearer. From this announcement and the history of the measure, we see three main potential scenarios for the development of UK CPS rates:

- a low case in which the government scraps the CPS entirely from 2016/17 onwards, with the CPS at zero £/tCO_2. Hence, we assume that the government implements the lowest possible CPS rate within its proposed 'cap' that applies to 2019/20,[30] and does not re-introduce it afterwards;

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25 IEA, World Economic Outlook 2015

26 DECC, Fossil Fuel Price Projections, November 2015; and

DECC, Updated short-term traded carbon values used for UK public policy appraisal, 18 November 2015.

27 In forming annual price forecasts using the WEO scenarios, we interpolate commodity prices from the beginning of 2016 to 2020 when the IEA long-term forecast starts.

28 DECC produces annual price forecasts, so unlike with the IEA scenarios, in forming annual price forecasts we jump to these forecasts straight away from the beginning of 2016.

29 HM Treasury, Budget 2014, p33.

30 A 'cap' on the CPS rate implies that, in practice, the rate implemented could range anywhere between the proposed £18/tCO_2 and zero (assuming the government will not be subsidising British utilities).

- a central case in which the CPS rate remains frozen at its current level of £18/tCO_2 indefinitely; and
- a high case in which the government reverts back to its original policy on the CPS from 2019/20, reinstating the original trajectory for the carbon price floor (£30/tCO_2 in 2020, rising to £70/tCO_2 in 2030, real 2009 prices).

3.5.2. Other assumptions required for computing fuel costs

In addition to the range of long-term projections on coal, gas and CO_2 prices, we also make assumptions regarding a number of other components of the marginal cost of energy, in order to allow us to assess the alternative commodity price scenarios:

- We obtained standard CO_2 emission rates for coal and gas from the Carbon Trust.[31]
- For thermal efficiency, we have examined a range of efficiencies for coal and CCGT gas plants, the former ranging from 30-36% and the latter from 44-53% (HHV, sent-out). When we compare the marginal cost of CCGT gas plant in Britain to those in the rest of the EU, we assume 49% efficiency (HHV, sent-out) for European plant.
- We take variable O&M cost assumptions of £1.32/MWh(e) for CCGT gas and £2.22/MWh(e) for coal (real 2008), and hold these assumptions constant in real terms. These figures are based on the latest generation cost assumptions prepared for DECC by Parsons Brinckerhoff, plus market charges (eg. BSUoS).
- In order to turn the market price for coal and gas into a delivered price for the two commodities, we include transport costs in our forecast. We assume total transport costs for coal generation of approximately £1.38/MWh_t(real 2008), which we add to the forecast of the ARA API#2 price (freight differential to GB vs ARA, port charges plus inland transport costs of £0.73/ MWh_t (real 2009)). For gas, we add the NGG NTS exit commodity charge of £0.357 pence per MWh_t (real 2015), based on National Grid's latest charging statement.[32] We hold these assumptions constant in real terms.

3.5.3. Implications for the competitiveness between GB coal and GB gas plant

Based on our assumptions above, we projected the marginal cost of coal and CCGT gas from 2015 to 2030 under a number of policy and CPS scenarios.

Figure 3.2 is a 3x3 matrix illustrating the evolution of the marginal cost of coal and gas in Great Britain under a number of scenarios. Vertically, the cases vary across the IEA's policy scenarios, with policies on emissions abatement becoming broadly more aggressive from top to bottom. Horizontally, the cases vary by our assumptions regarding the evolution of the UK CPS rate, with support rates increasing from left to right.

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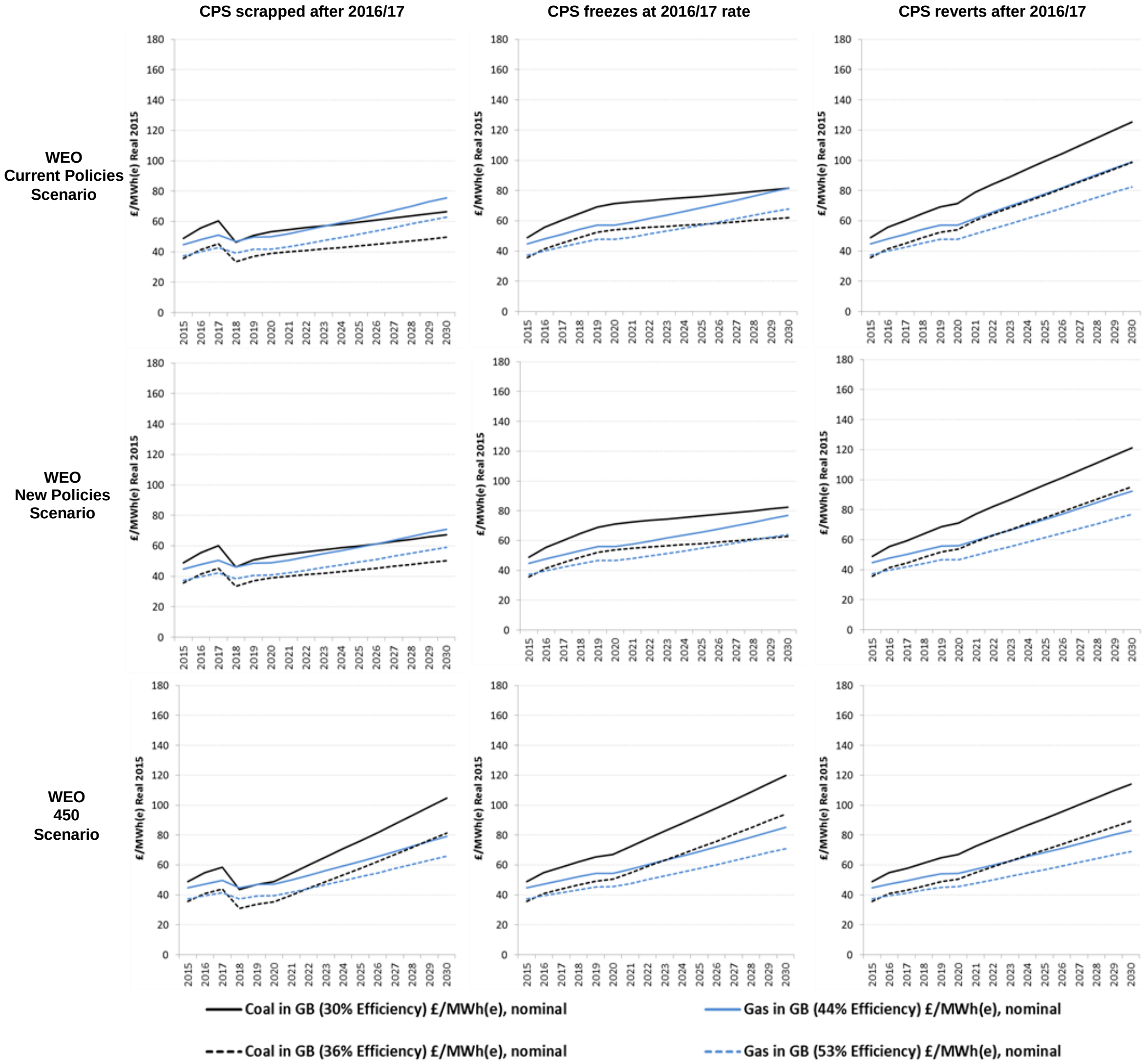
31 Carbon Trust, Conversion Factors, 2011 update

32 National Grid, NTS Transportation Statement, October 2015, p 4.

In general, we see that coal and gas tend to be closer in the merit order in cases with less aggressive assumptions regarding global efforts to mitigate climate change and with lower CPS rates in Great Britain:

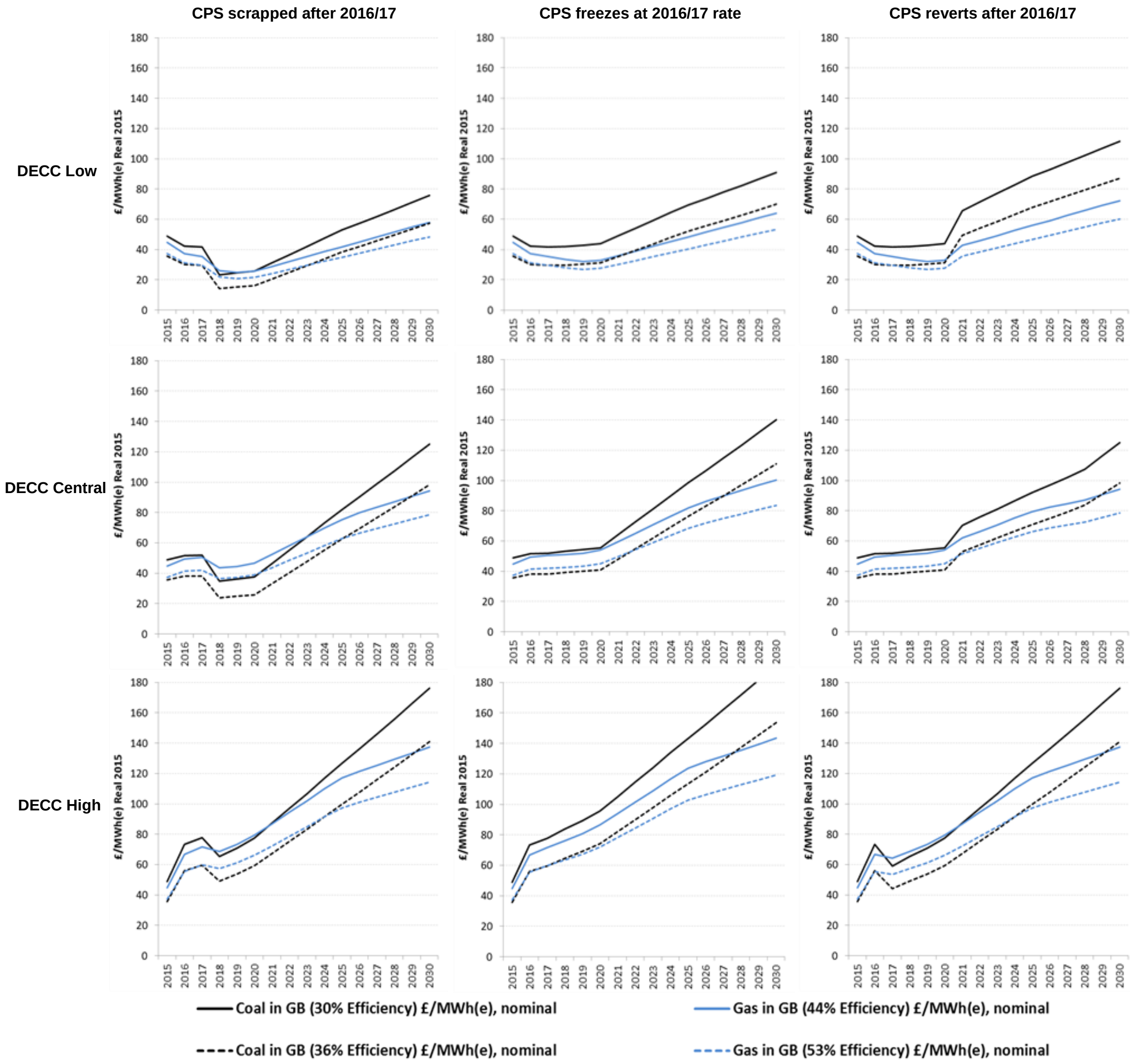
- All the panels in Figure 3.2 show that, based on current fossil fuel and CO_2 prices, coal and gas are relatively close in the merit order. Hence, a policy that disadvantages coal and favours gas plant would tend to have a relatively large impact on despatch.
- As the top-left-hand-panel of Figure 3.2 shows, a scenario with international commodity prices based on the IEA's Current Policies scenario, combined with the low case on the CPS rates, suggests that coal and gas remain extremely close in the merit order for the entire period, with coal becoming gradually more competitive than gas CCGT towards the end of the modelling horizon.
- The central case (New Policies plus the central CPS scenario) has coal becoming gradually less competitive than gas until the around 2020. Thereafter, there is some very gradual improvement in the position of coal relative to gas, as we assume the CPS rates are frozen at their current nominal levels with no ongoing inflation adjustment.
- As international climate change policies become more ambitious or British CO_2 prices rise relative to the EU ETS price (towards the bottom and right of Figure 3.2), coal plant becomes less competitive relative to gas plant. In the extreme, combining a high case on CPS rates and the IEA's 450 scenario, coal falls materially below gas in the merit order.

Figure 3.2
Marginal Cost by Generation Source:
Coal vs. Gas in GB for a Range of Efficiencies (IEA)



We have also prepared similar charts for the DECC commodity price scenarios. As Figure 3.3 shows, when we take the DECC low case and the low case on CPS, coal is further ahead of gas in the merit order for the first few years of the modelling horizon, as compared to the IEA Current Policies/low CPS scenario shown in Figure 3.2. However, in all the DECC price scenarios, coal eventually becomes less competitive than gas during the 2020s. In all of the DECC scenarios, the spread between the marginal costs of coal and gas CCGT generation are relatively similar. Hence, the DECC scenarios provide less variation in coal/gas marginal generation costs than the IEA's New Policies/450 scenarios.

Figure 3.3
Marginal Cost by Generation Source:
Coal vs. Gas in GB for a Range of Efficiencies (DECC)



3.5.4. Implications for the relative competitiveness of GB gas plant and those in neighbouring markets

Figure 3.4 and Figure 3.5 compare the marginal cost of generation from CCGT gas plant in Great Britain compared to neighbouring markets, which is important because the CPS rates mean the marginal cost of generation will tend to be higher in Britain than elsewhere in the EU, which influences modelled interconnection flows.

As described above in Chapter 2, in our modelling, we price imports from continental Europe at the marginal cost of a gas-fired CCGT with "average" (ie. 49% efficiency). Hence, we compare this marginal cost with a range of marginal costs for GB gas plant. The CPS also affects competition between GB coal and EU gas, but the competitiveness between coal and gas is discussed above, so we have kept coal out of these charts for simplicity.

In the case where we assume the CPS is scrapped there is no spread between the marginal costs of British and EU gas plants from 2018. In the low/central DECC and Current/New Policies IEA scenarios, EU gas plant is above GB gas plant in the merit order where we assume the CPS rates are frozen. However, the effect of the CPS is lower in the DECC High and IEA 450 scenarios, as carbon prices are reaching the levels we assumed are being targeted by the UK government anyway, ie., without any additional top-up using the CPS.

Figure 3.4
Marginal Cost by Generation Source:
EU Gas vs. GB Gas for a Range of Efficiencies (IEA)

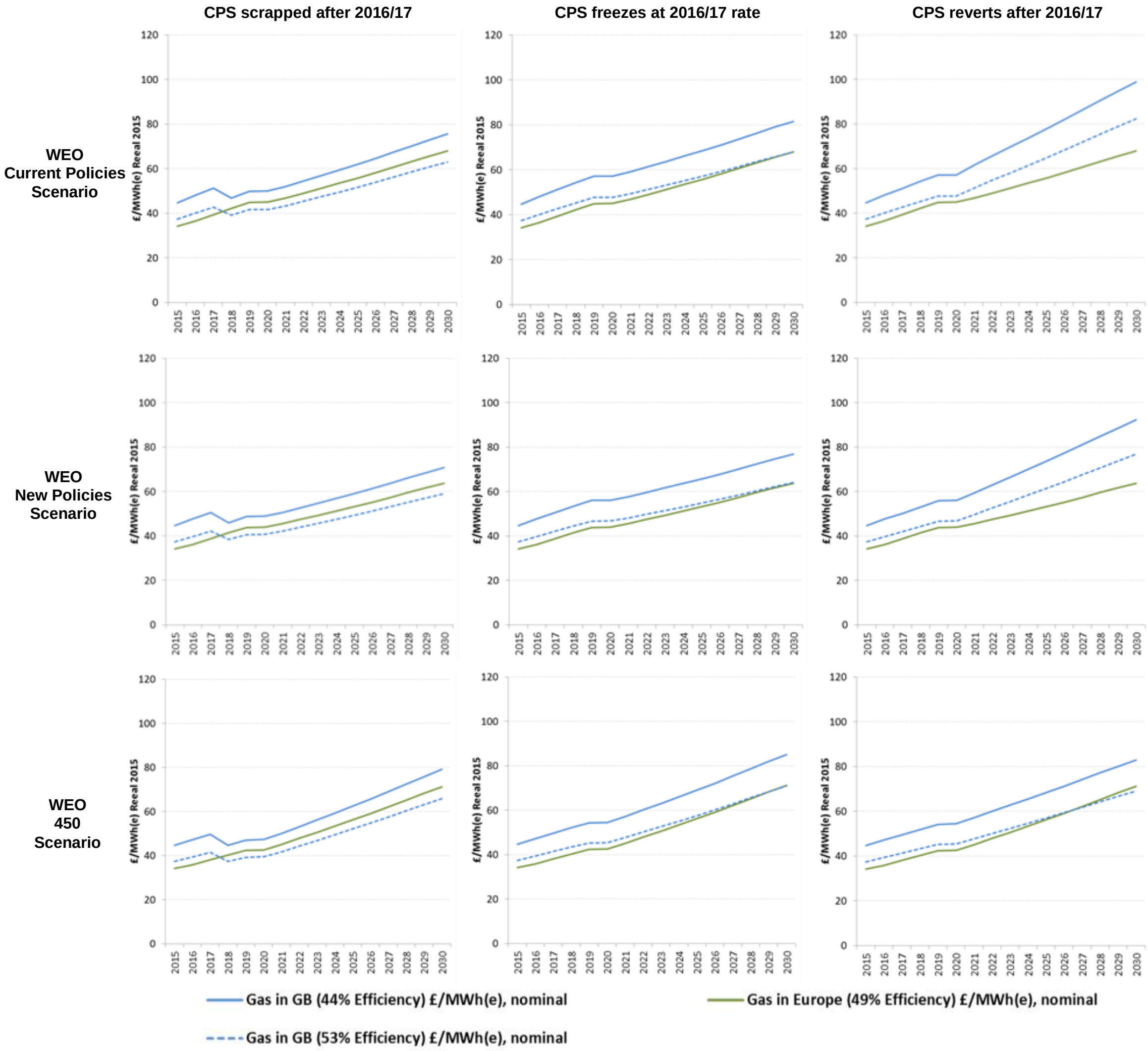
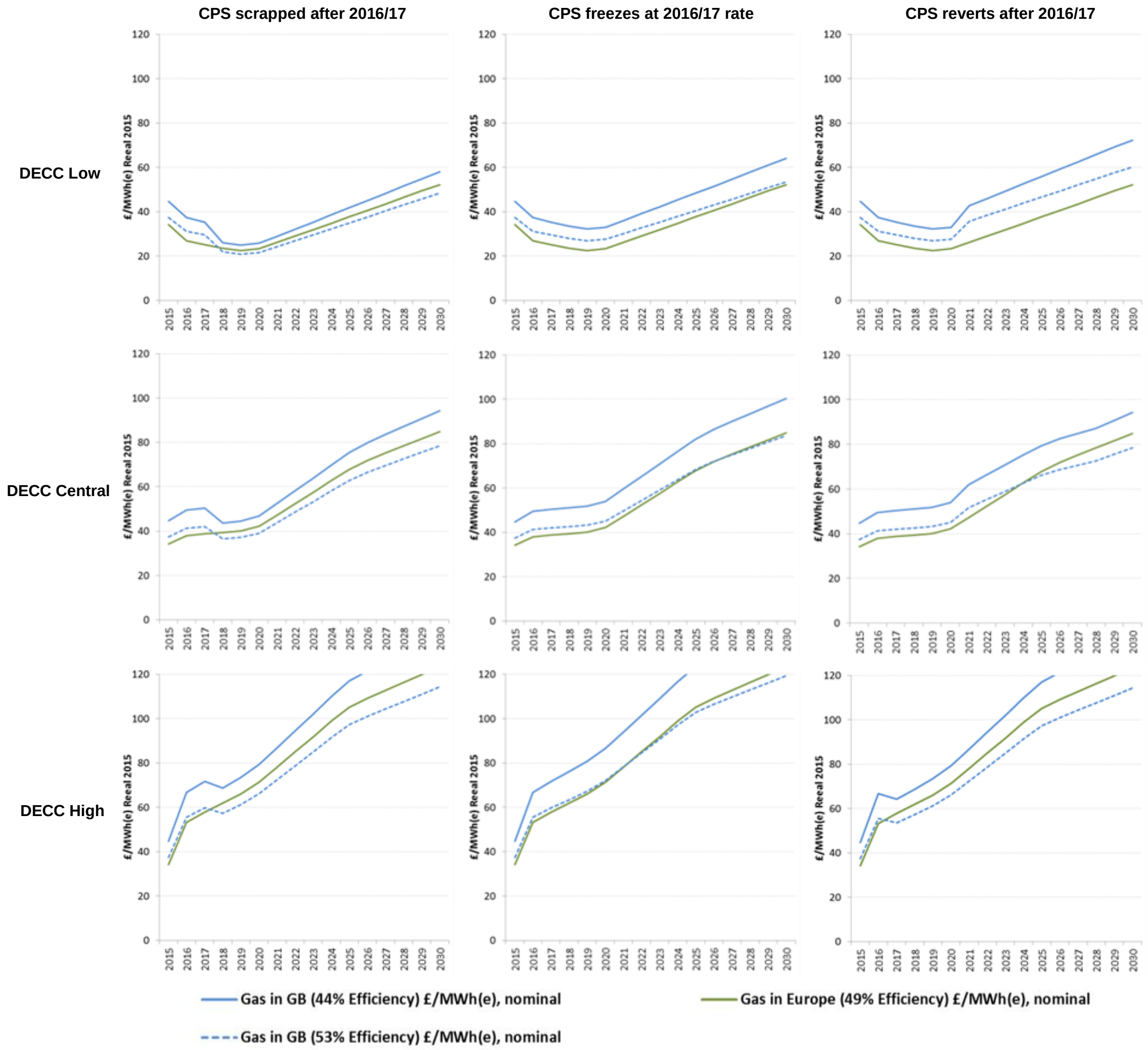


Figure 3.5
Marginal Cost by Generation Source:
EU Gas vs. GB Gas for a Range of Efficiencies (DECC)



3.5.5. Conclusions on scenario definition

As noted above, our overriding objective is to define a range of scenarios on the relative position of coal and gas in the merit order. The research above suggests that we can achieve this objective by examining a range of scenarios on international commodity prices, and a range of scenarios on the UK CPS.

However, there is a choice to make on whether to use the IEA or the DECC long-term fuel price scenarios. The IEA's scenarios emerge from a modelling exercise that examines the impact on energy prices from world energy policy, whereas we understand DECC's scenarios are based on judgment. Hence, the IEA scenarios may represent a more credible basis for long-term modelling, and we usually use the IEA scenarios in our modelling work for this reason. Relying on the DECC scenarios may also be less informative than relying on the IEA scenarios as the DECC scenarios have less variation in coal/gas CCGT marginal costs.

Adopting the approach of using the IEA commodity prices would lead to us running three scenarios, the second of which would be our "reference scenario":

- IEA Current Policies + Low CPS (abolished after 2016/17);
- IEA New Policies + Central CPS (support rates frozen indefinitely); and
- IEA 450 + High CPS (Carbon Price Floor = £30/tCO_2 in 2020, £70/tCO_2 in 2030, real 2009 prices).

However, there is a case for substituting the first of these scenarios (Current Policies + Low CPS) with the equivalent scenario using the DECC low case, on the basis that this is the scenario in which coal appears the most competitive (relative to gas CCGT) of all those considered above. Hence, given we are seeking to examine a wide range of sensitivities, in practice we have run the following three scenarios.

- Low case: DECC Low Case + Low CPS (abolished after 2016/17);
- Reference case: IEA New Policies + Central CPS (support rates frozen indefinitely); and
- High case: IEA 450 + High CPS (Carbon Price Floor = £30/tCO_2 in 2020, £70/tCO_2 in 2030, real 2009 prices).

4. Modelling Results

This chapter describes the results from each stage of the modelling process described in Chapter 2, and concludes by presenting the estimated costs and benefits of the zonal transmission charging mechanism.

4.1. Projections of Market Fundamentals

As described in Chapter 2, the first stage of our modelling work was to forecast the evolution of market fundamentals across our three commodity price scenarios described in Chapter 3 using NERA's Aurora model. We then provided data from these model runs (installed capacity, generation marginal costs, etc) to Imperial, which they put into DTIM in order to compute marginal loss factors. The key features of the model runs we provided to Imperial are described below.

4.1.1. Supply-demand balance

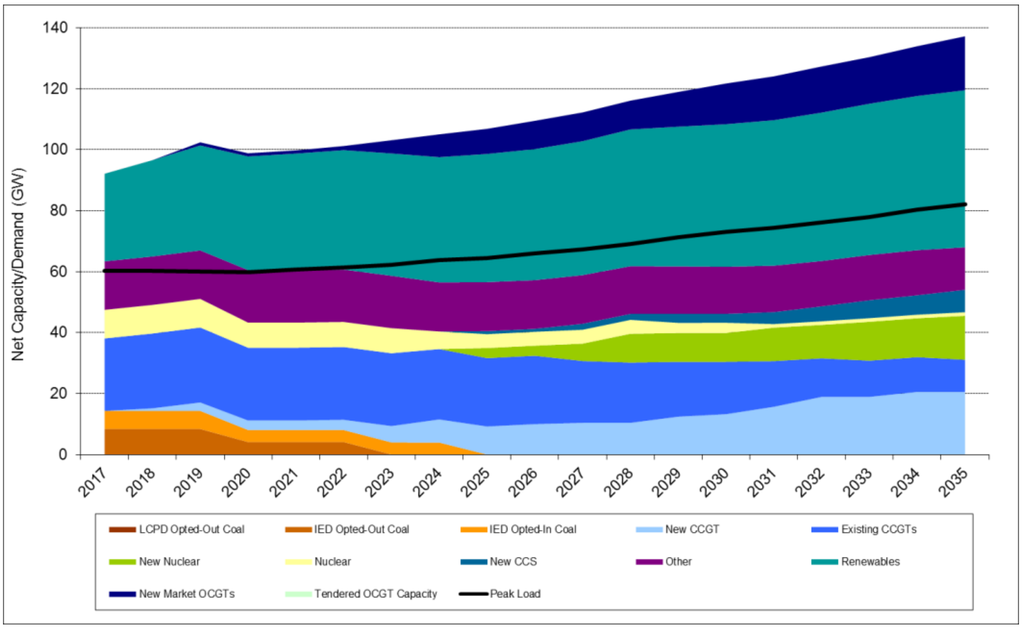
Figure 4.1 shows our projection of peak demand and net generation capacity in our reference case over the modelling horizon. Over the period to 2023, coal plants which we assume opt out of the IED close gradually, with the remainder that opt in closing two years later in 2025. This is in line with the government's plan to end coal power generation by 2025, which we reflect in our modelling assumptions (see above). Existing nuclear plants also close gradually over the modelling horizon, in accordance with licensed life extensions, with new nuclear plants coming online from 2025.

We assume no new CCS generation capacity in the short term (reflecting the recent government decision to withdraw funding for CCS demonstration), but assume that new CCS capacity will ultimately come onto the system following the government's projections in the 2015 UEEP document. As Figure 4.1 shows, new CCS capacity comes online in all scenarios from 2024 onwards, although this only forms a small proportion of the overall generation capacity of GB.

Our model deploys new CCGT and OCGT capacity endogenously to ensure energy demand is met, and to meet the reserve margin requirement. As Figure 4.1 shows, the model deploys new CCGT capacity gradually from around 2019, with continued investment as the existing coal fleet retires over the period to 2025. The model also selects investment in some peaking plants, which are mainly in place to meet the reserve margin requirement and fulfil a shortfall that exists between the closure of coal plant and the commissioning of new nuclear and CCS plant in the mid-late 2020s.

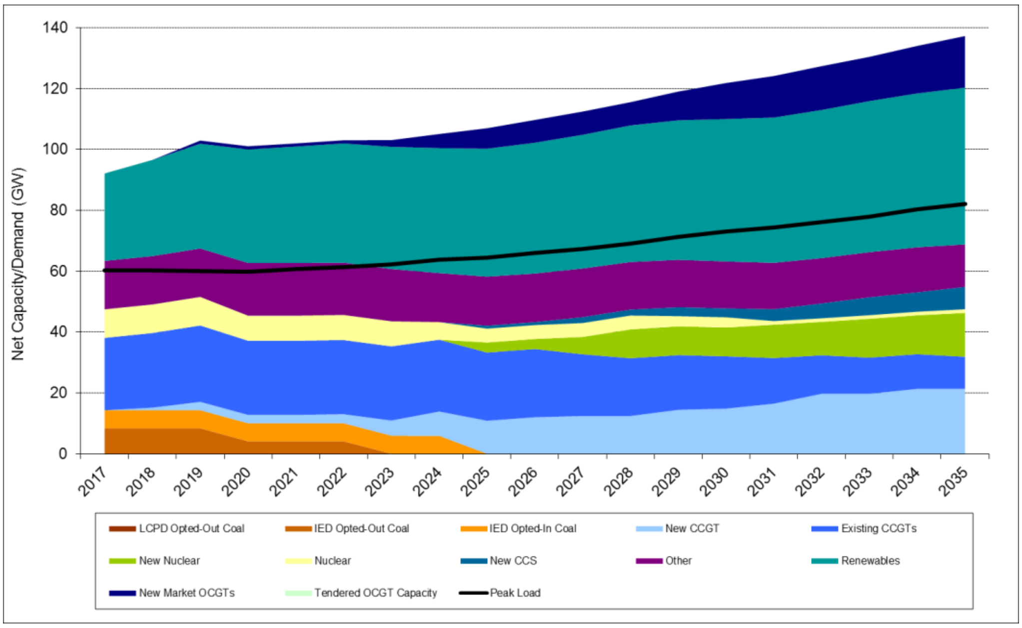
As Figure 4.2 and Figure 4.3 also show, these capacity projections vary immaterially across the low and high cases, primarily because the model has little discretion over the technologies that come online. Even in the high scenario where coal is relatively uncompetitive, coal plants are still used by the model as a source of capacity even though they generate little output in this case (see next section).

Figure 4.1
Supply-Demand Balance in the Reference Case: Peak Load vs Net Generation Capacity (GW)



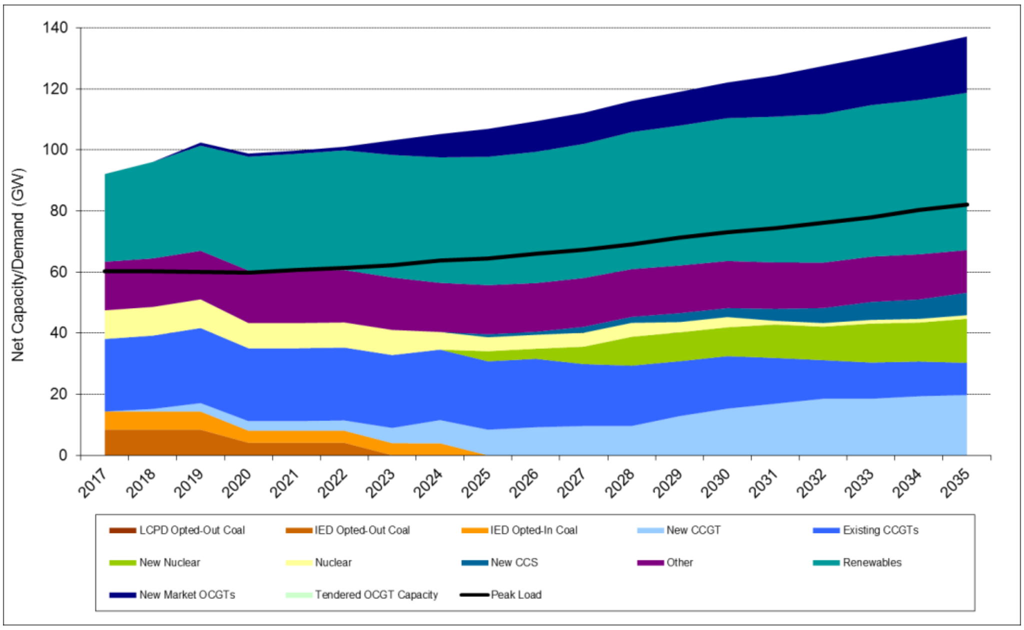
Source: NERA/Imperial

Figure 4.2
Supply-Demand Balance in the Low Case: Peak Load vs Net Generation Capacity (GW)



Source: NERA/Imperial

Figure 4.3
Supply-Demand Balance in the <u>High Case</u>: Peak Load vs Net Generation Capacity (GW)



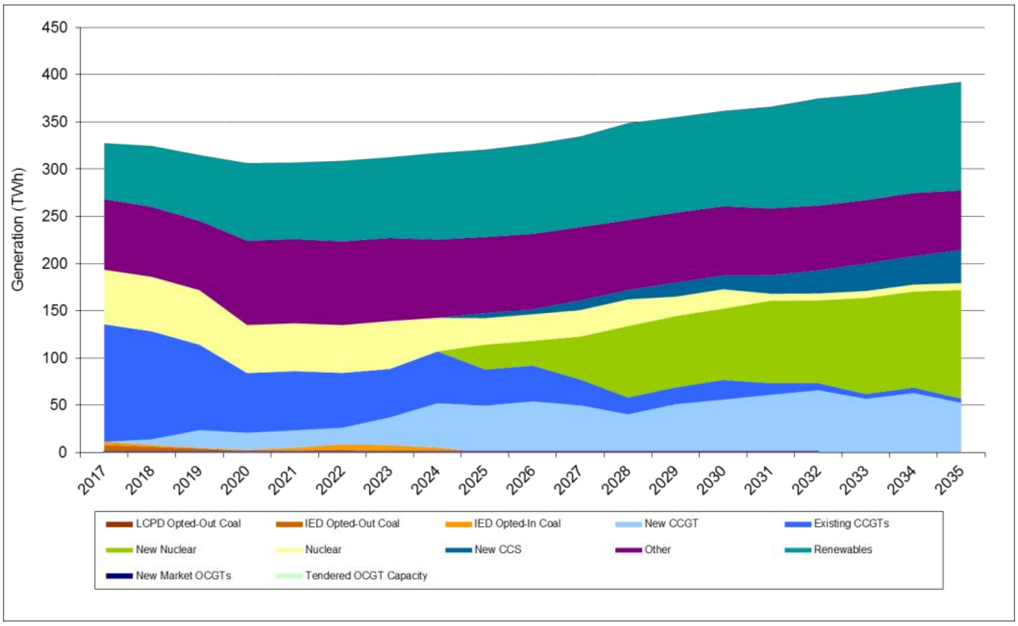
Source: NERA/Imperial

4.1.2. Generation mix

Figure 4.4 shows the generation mix in the reference case. Production from existing coal, gas and nuclear plants is gradually replaced throughout the modelling period by output from renewables, new nuclear, new CCGT and new CCS capacity.

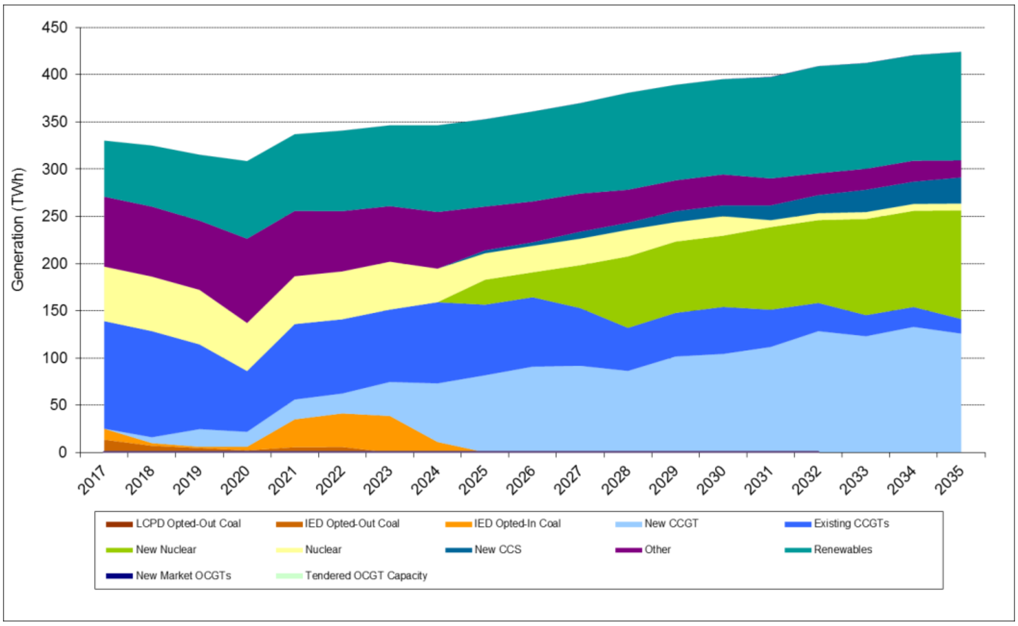
As Figure 4.5 also shows, existing coal plant serve a greater proportion of total demand in the low case during the early 2020s, as this scenario is the one in which coal is most competitive relative to gas in GB. Some coal-fired generation remains on the system until 2025, but this is a small share of the overall energy generated in all cases. Total energy production within GB is slightly higher in the low case, as in this scenario we assume the CPS mechanism is removed, making GB generators more competitive to those in neighbouring markets and hence increasing their market share.

Figure 4.4
Generation Mix in the Reference Case (TWh)



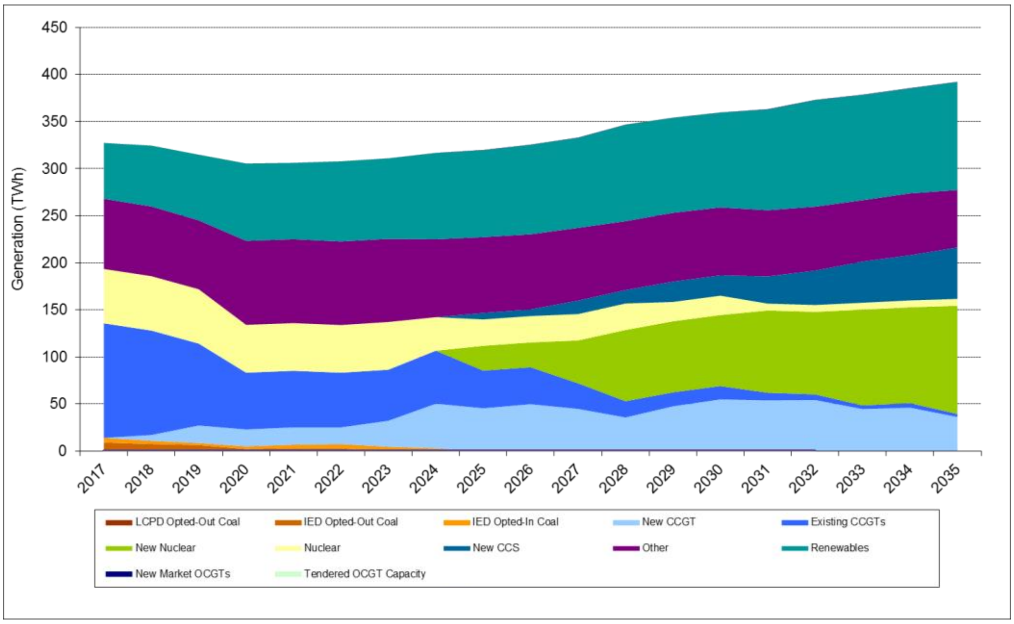
Source: NERA/Imperial

Figure 4.5
Generation Mix in the Low Case (TWh)



Source: NERA/Imperial

Figure 4.6
Generation Mix in the <u>High Case</u> (TWh)



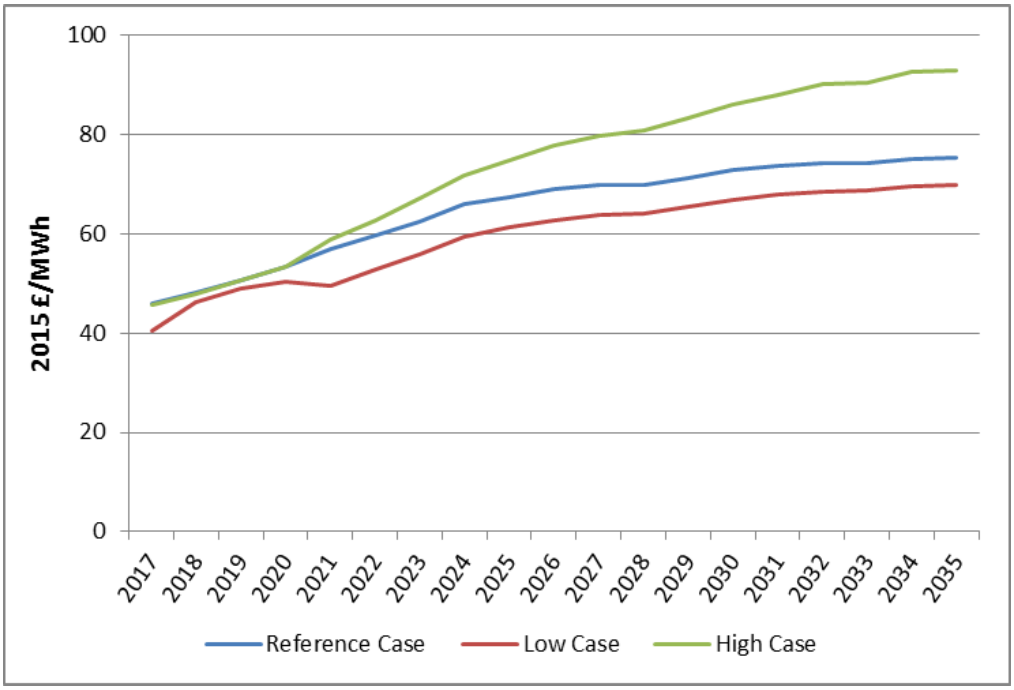
Source: NERA/Imperial

4.1.3. Wholesale price projections

As Figure 4.7 shows, across all scenarios our model predicts gradual growth in the wholesale energy price, which tracks up with assumed growth in fuel and carbon prices. The low case is systematically lower than the reference scenario, mainly because we assume the CPS mechanism is removed, given the differences in EU ETS and gas prices are relatively modest. The high case has prices rising markedly more quickly, mainly because of high CPS rates and EU ETS prices.

Figure 4.8 shows the corresponding projections of the capacity price, which are calibrated by the model in order to remunerate investments in sufficient generation capacity to satisfy the reserve margin constraint.

Figure 4.7
Wholesale Energy Price Projection across all Scenarios (£/MWh, Real 2015)



Source: NERA/Imperial

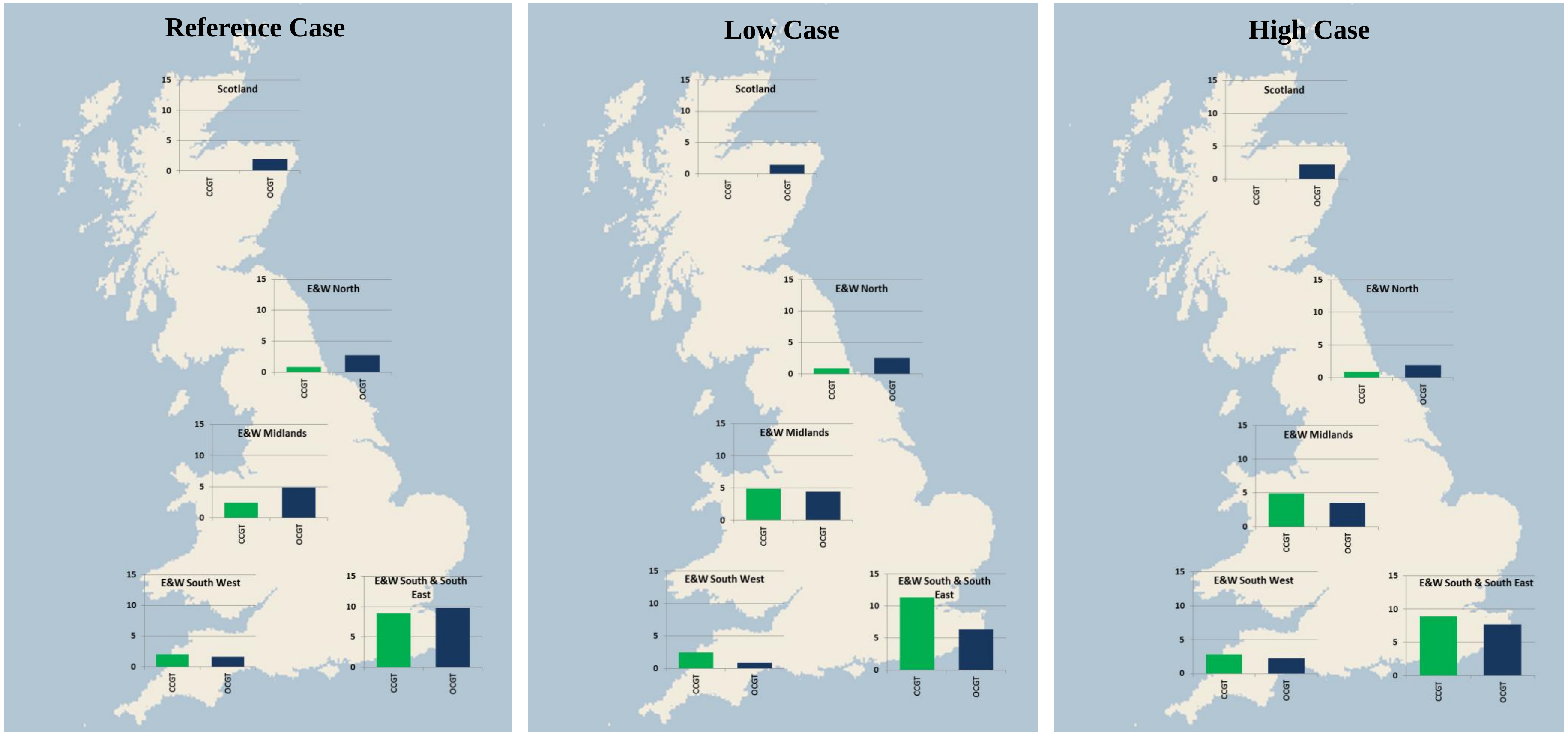
Figure 4.8
Capacity Market Price Projections across all Scenarios (£/kW/yr, Real 2015)

Source: NERA/Imperial

4.1.4. Locational investment assumptions

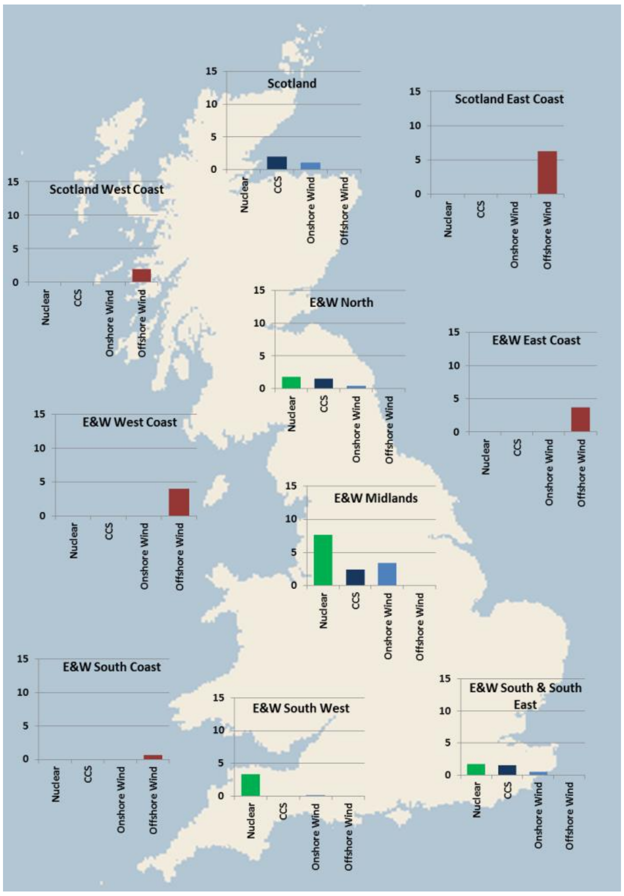
Figure 4.9 and Figure 4.10 show the locations of new thermal and low carbon plants deployed over the period to 2035. In all cases, investment in new CCGT and OCGT generation is located primarily in the midlands and the southern part of England Wales, which occurs as these are the regions in which our assumed TNUoS prices, the main driver of locational investment decisions, are lowest. Investment assumptions in low carbon plants are common across scenarios. Whilst new onshore and offshore wind generation are located in Scotland and the northern regions of England and Wales, nuclear investment is concentrated predominantly in the midlands and the south of England and Wales.

Figure 4.9
Locations of New CCGT and OCGT Plant by 2035 by Scenario (MW)



Source: NERA/Imperial

Figure 4.10
Locations of Low Carbon Plant by 2035 in all Scenarios (MW)

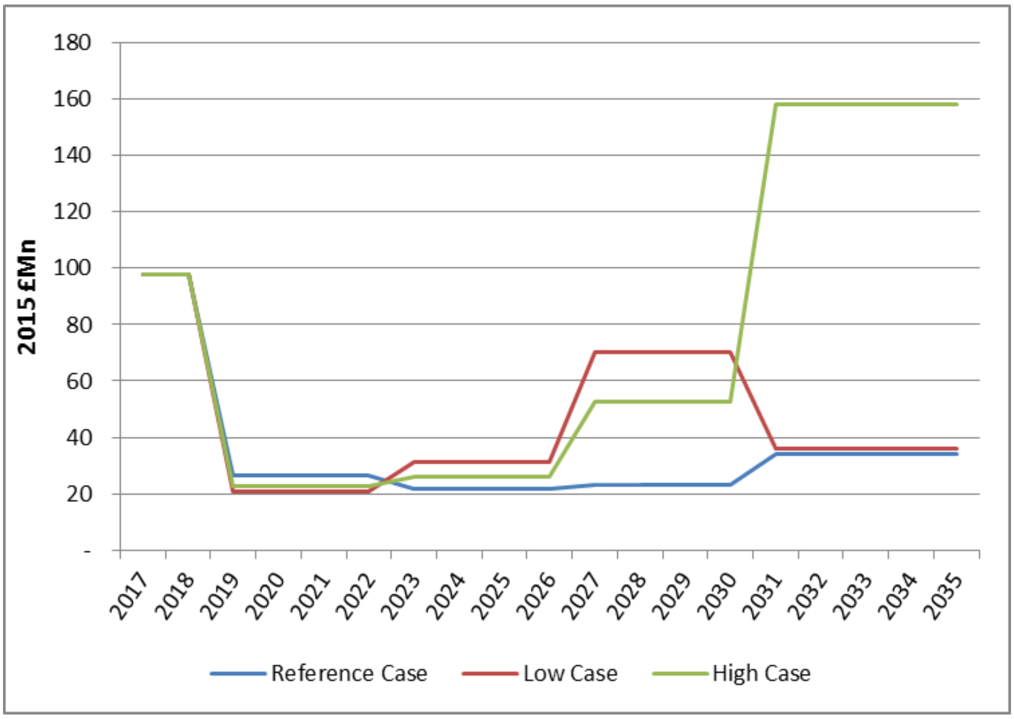


Source: NERA/Imperial

4.2. Transmission System Modelling Results

As described above, the next stage of our modelling is to pass the data on the generation mix shown above to DTIM, which (1) optimises transmission investment making a least cost trade-off between investment and constraint costs, and (2) computes marginal loss factors. Figure 4.11 shows projections of transmission constraint costs across the three commodity price scenarios.

Figure 4.11
Constraint Costs by Scenario



Source: NERA/Imperial

As described in Section 2.1.2, DTIM models the transmission system using a range of representative "snapshots", which combine to represent a range of demand levels and levels of wind production levels following a "load duration curve" approach to market modelling. The loss factors represent (for each DTIM snapshot, epoch and zone) the marginal change in total transmission losses that would arise from a marginal change in net injections.

However, in order to convert these loss factors into inputs into Aurora, which is a full chronological model, we need to derive full hourly time series from the estimated loss factors by snapshot. We do this, as described in Appendix A, using a regression procedure that maps DTIM estimates to calibrate a formulaic relationship between loss factors (the dependent variable in the regression) and demand and wind (the explanatory variables).

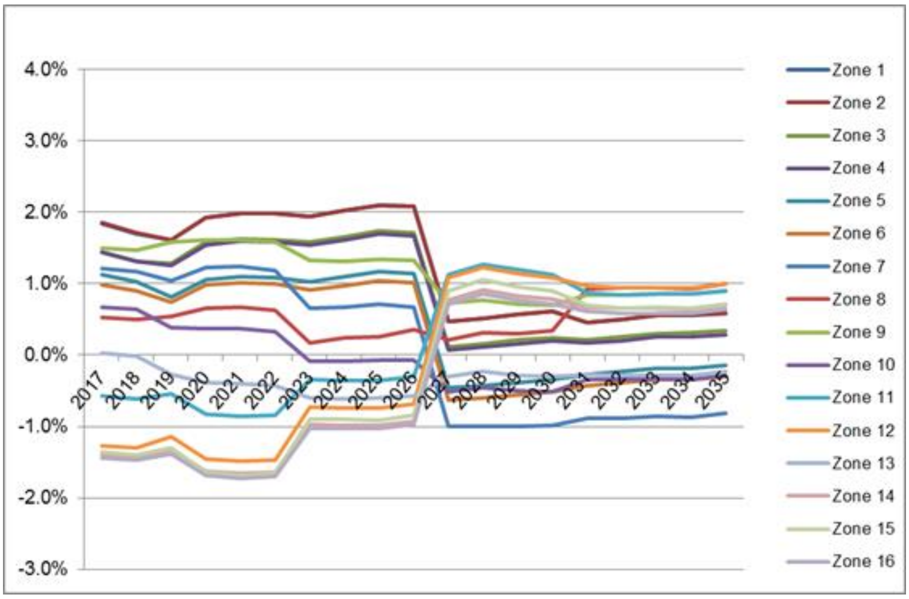
As a result, we obtain the hourly loss factors shown in Figure 4.12 by DTIM zone for the reference case. The figure shows annual averages of hourly loss factors. Our modelling suggests that TLMs change materially over time, reflecting expansion in the transmission system and changes in the generation mix. In particular, we see ‘switching’ in TLMs between the northern and southern regions of the country:

- At the start of the modelling horizon, the marginal effect of increasing generation (reducing consumption) in the north is to increase losses, and as such we assign a positive TLM to these zones that, when implemented, would marginally reduce the marginal cost of consumption (increase the cost of generation) in the north.
- As an increasing volume of generation takes place in the south, driven mainly by the locations of new thermal plant that locate in the south in response to TNUoS signals, this situation reverses. Increasing generation or reducing demand in the south reduce losses to a lesser extent than in the first half of the modelling horizon, and from 2026 actually *increases* losses. Hence, in the latter part of the modelling horizon, we assign a positive TLM to generators in the south, the effect of which is to marginally reduce the marginal cost of consumption (increase the cost of generation) in the south.

As Figure 4.13 and Figure 4.14 also show, the modelled TLMs are relatively similar across the three fundamentals cases, reflecting similar patterns of locational investment and the limited extent to which the model can alter the pattern of despatch amongst the generation fleet (see Figure 4.5 and Figure 4.6).

These TLMs are also presented in tabular format in Appendix B for each of the 16 DTIM zones.

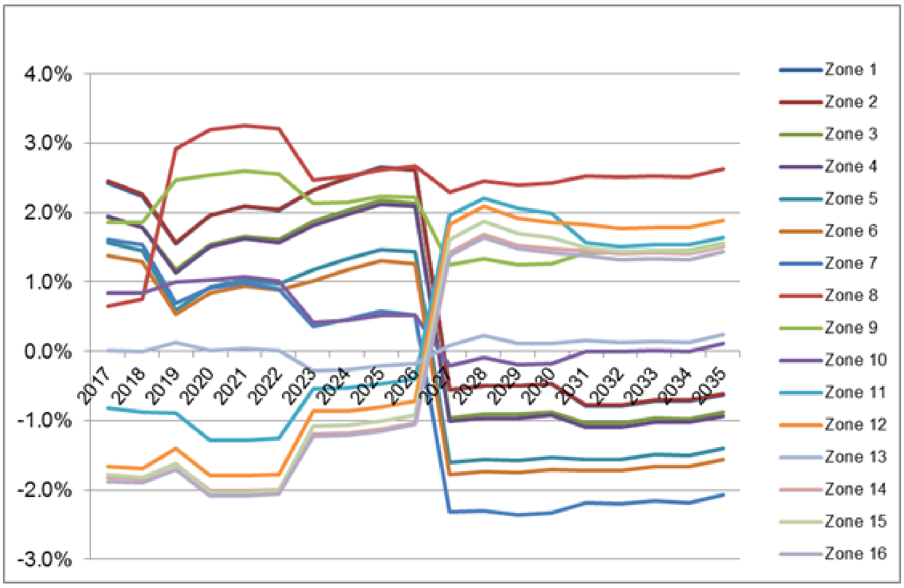
Figure 4.12
Annual Average Projected Loss Factors by Zone in the Reference Case: 100% Generator TLMs



Source: NERA/Imperial[33]

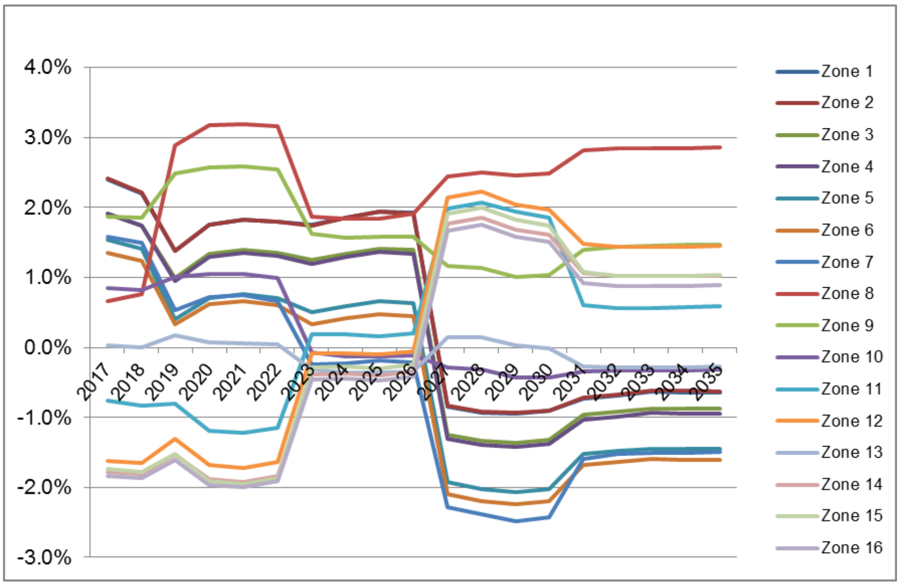
[33] Note, a TLM of +1% means that a 1 MWh increase in injections increases system losses by 0.01 MWh.

Figure 4.13
Annual Average Projected Loss Factors by Zone in the <u>Low Case</u>: 100% Generator TLMs



Source: NERA/Imperial

Figure 4.14
Annual Average Projected Loss Factors by Zone in the <u>High Case</u>: 100% Generator TLMs



Source: NERA/Imperial

The final step before these loss factors are put into the Aurora model is to compute the average loss factor within each season, as we hold the TLMs used in the model constant for each season. This is similar to the approach envisaged under BSC Modification P229. At this final stage, we also apply the assumed split between generation and demand, which, as we discuss below, varies between 45:55 and 100:0.[34]

4.3. The Anticipated Effects of Locational Loss Factors

The next stage in our modelling is to run Aurora a number of times to estimate the costs and benefits that result from applying zonal TLMs. We estimate six scenarios: three commodity price cases, and two scenarios on the G:D split (45:55 and 100:0).

In principle, as a result of sending a signal to generators regarding the change in transmission loss multipliers they impose on the system, we should expect to see a reduction in transmission losses, in essence a reduction in the amount of energy that consumers need to buy. Moreover, we should expect to see a greater reduction in losses in the 100:0 G:D split scenarios compared to the 45:55 G:D split scenarios, on the basis that the former approach sends a sharper signal regarding the marginal cost of losses.

However, in computing the overall welfare benefit, we also need to account for expected offsetting increases in costs. With socialised transmission losses, generators will not consider the effect of their production decisions on losses, and thus the selected pattern of despatch will tend to minimise only their own private avoidable costs of generation, notably fuel, CO2 and variable O&M costs. With locational loss factors, we expect generators to depart from this pattern of despatch as they consider the effect of their production decisions on losses, and hence increase their own private avoidable costs of generation in order to realise the system-wide benefit of reduced losses.

Overall, however, we would expect to see a net reduction in costs as a result of the policy, as pricing in an avoidable cost ought in theory to improve the efficiency of despatch from a whole-system perspective.

Moreover, as we discuss further below, market prices may also change as a result of the policy to introduce locational transmission loss factors. Specifically, some generators will win from the policy and others will lose, and there is no *a pirori* reason to believe that the effect on prices (through the change in the marginal cost of the marginal generator) will necessarily be positive or negative. Indeed, in some hours of the year, the effect on price (through a change in the marginal cost of the marginal unit) may be positive, and in other hours of the year it may be negative. These changes in price will create transfers between consumers and producers.

By altering the shape of the supply curve and changing the market clearing price within Britain, we would also expect to see some change in imports and exports. These effects may increase or decrease both the volume of production that takes place in Britain and British system costs and market prices, and may create transfers between Britain and neighbouring markets, which is a feature of the results we also discuss below.

[34] The process of averaging across seasons, and in some cases applying a 45:55 G:D split that dilutes the locational signal, means that the locational loss factors to which generators are exposed does not precisely reflect our estimate of the underlying marginal loss factor, but it ought to result in a markedly more accurate signal regarding locational variation in loss causation than can be achieved through the current socialised approach.

4.4. Changes in Costs as a Result of Locational Loss Factors

4.4.1. Breakdown of annual changes in cost

As the discussion above anticipates, Figure 4.15, Figure 4.16 and Figure 4.17 show, for the 45:55 G:D split case, that we do indeed find a modelled *savings* in costs in every year as a result of the policy to introduce locational loss factors. (Figure 4.18, Figure 4.19 and Figure 4.20 displays the same thing but for the 100:0 G:D split case.) The figures also show the decomposition of changes in costs into a number of effects:

- Transmission losses are lower in every year from 2017, when we assume the policy would be introduced. As Figure 4.21 shows, we see larger reductions in transmission losses in the 100:0 G:D split case than in the 45:55 case, reflecting the sharper locational signal that is conveyed to generators. In all cases, we compute the change in losses by multiplying the change in hourly output of each plant by the estimated marginal loss factor, derived as described above. We value the change in losses at the prevailing hourly wholesale energy price, then sum the effect across all hours of the year to obtain the aggregate annual saving;[35]
- Offsetting this, we see some increases in generation costs. Figure 4.15, Figure 4.16 and Figure 4.17 separate this effect between the change in generation costs in Britain and the change in costs in neighbouring markets that can arise because the volume of imports to/from neighbouring markets changes. Hence, the effect of the policy can be to reduce generation costs and transmission losses within Britain, but this would be offset by rising costs in neighbouring markets. Likewise, it is possible that in some years we would see generation costs within Britain rising by more than the reduction in losses, but this would be offset by falling costs in neighbouring markets;
- Further, we also separate out the value of SO_2 and NOx reduction, on the basis that these are environmental externalities that are not priced into generators production decisions.[36] Hence, these costs could rise or fall as a result of the policy, and we have no *a priori* reason to believe they would necessarily change in either direction. Figure 4.22 shows very small reductions in the cost of these emissions to GB producers, with savings marginally greater in the 100:0 G:D split case than in the 45:55 case.

Note that across all the results presented in this section[37], we adopt the convention of presenting benefits of the policy (such as reduced losses) as positive numbers, and costs of the policy (such as higher generation costs) as negative numbers.

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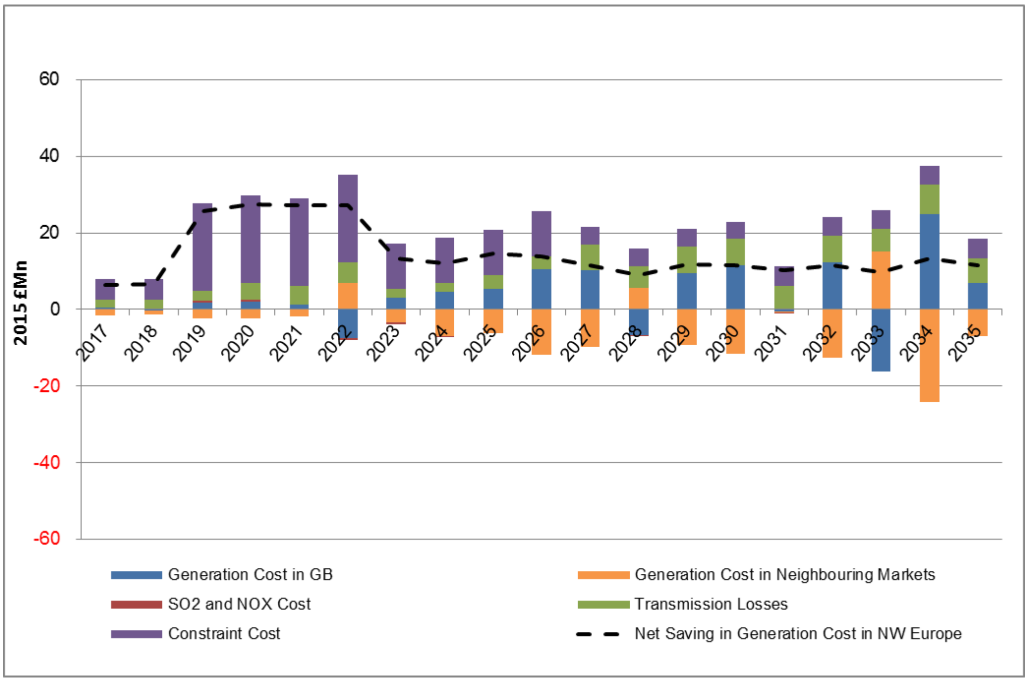
[35] Note, we use the underlying loss factor derived from DTIM and our regression procedure to compute the change in losses, and not the loss factor that is averaged across seasons and (in some cases) reduced in magnitude by applying a 45:55 G:D split.

[36] Regulation is in place to moderate the emission of these pollutants from the power sector, but the form of this reduction (unlike CO_2 pricing, for instance) does not link the costs of emissions to the costs incurred or revenues earned from hour-to-hour production decisions.

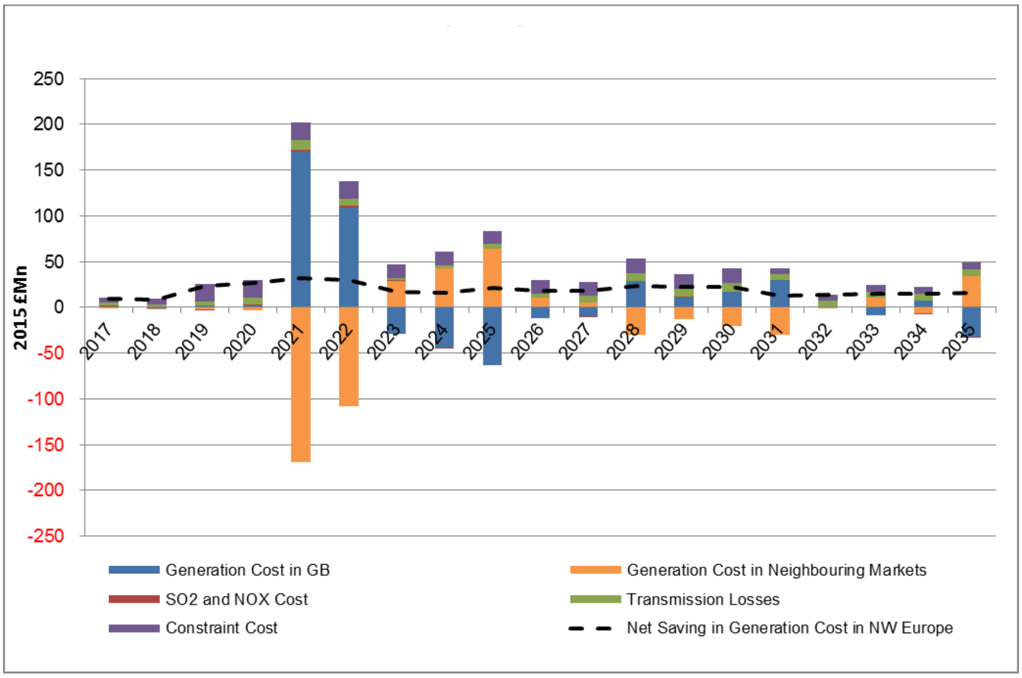
[37] With the exception of changes in the baseload energy price and capacity market price.

Figure 4.15
Composition of the Annual Saving in Power Sector Costs in NW Europe in the <u>Reference Case</u>: Uniform Case vs. <u>45% Generator TLMs</u> (£Mn, Real 2015)



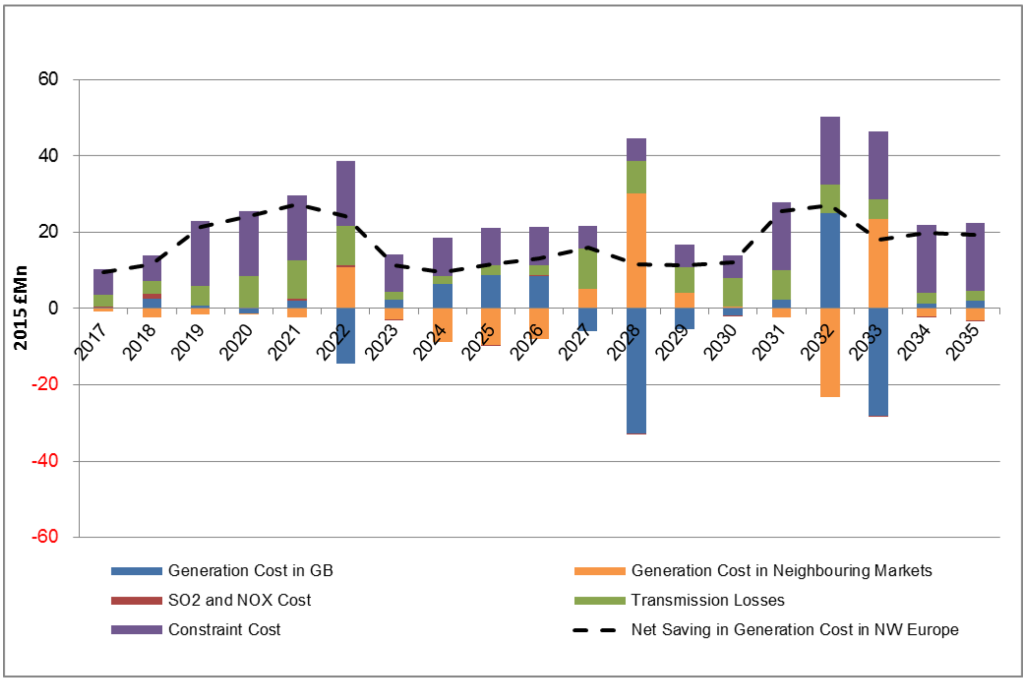
Source: NERA/Imperial

Figure 4.16
Composition of the Annual Saving in Power Sector Costs in NW Europe in the <u>Low Case</u>: Uniform Case vs. <u>45% Generator TLMs</u> (£Mn, Real 2015)



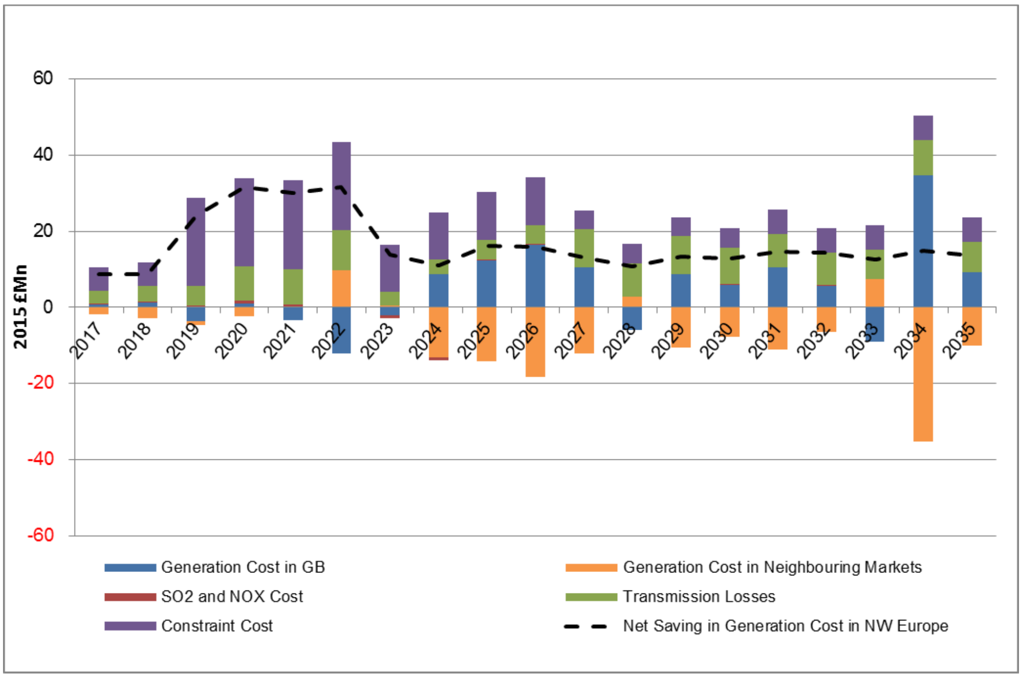
Source: NERA/Imperial

Figure 4.17
Composition of the Annual Saving in Power Sector Costs in NW Europe in the <u>High Case</u>: Uniform Case vs. <u>45% Generator TLMs</u> (£Mn, Real 2015)



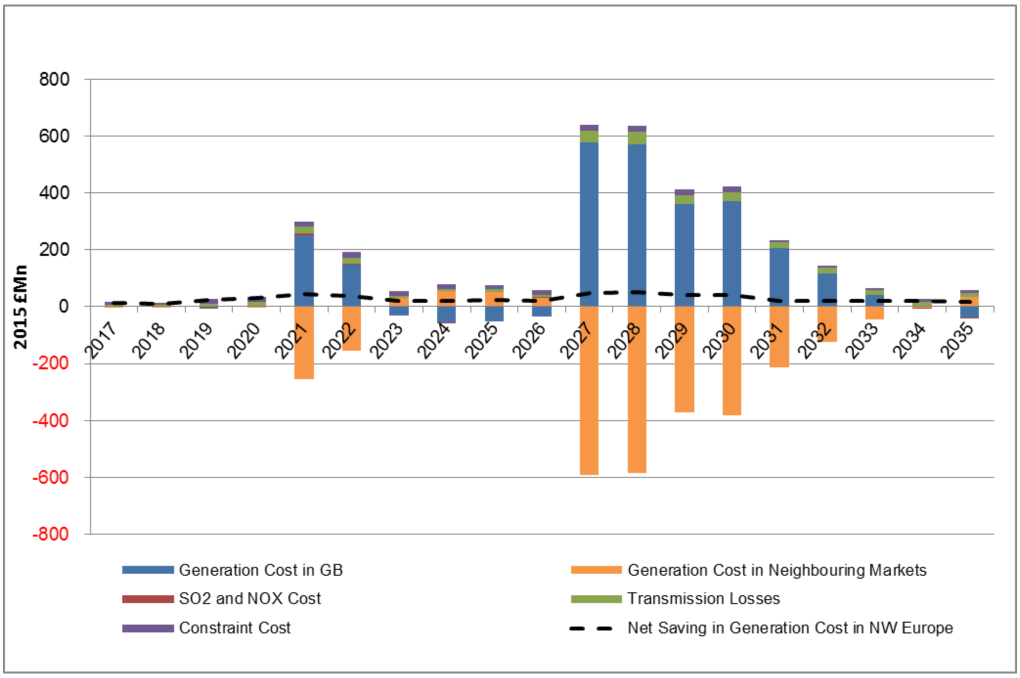
Source: NERA/Imperial

Figure 4.18
Composition of the Annual Saving in Power Sector Costs in NW Europe in the <u>Reference Case</u>: Uniform Case vs. <u>100% Generator TLMs</u> (£Mn, Real 2015)



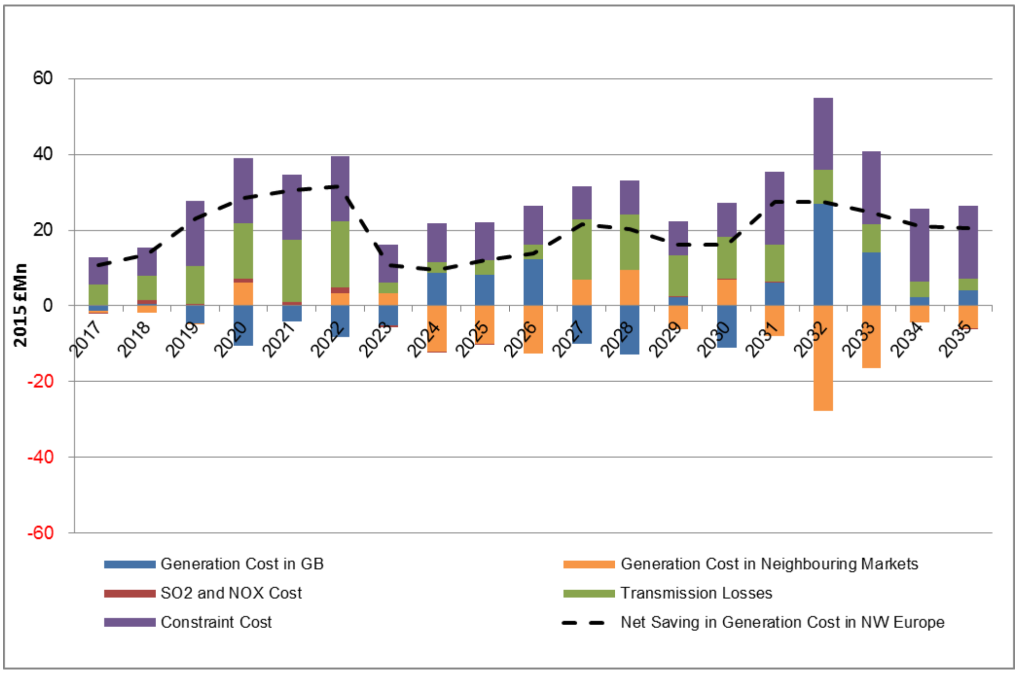
Source: NERA/Imperial

Figure 4.19
Composition of the Annual Saving in Power Sector Costs in NW Europe in the Low Case: Uniform Case vs. 100% Generator TLMs (£Mn, Real 2015)



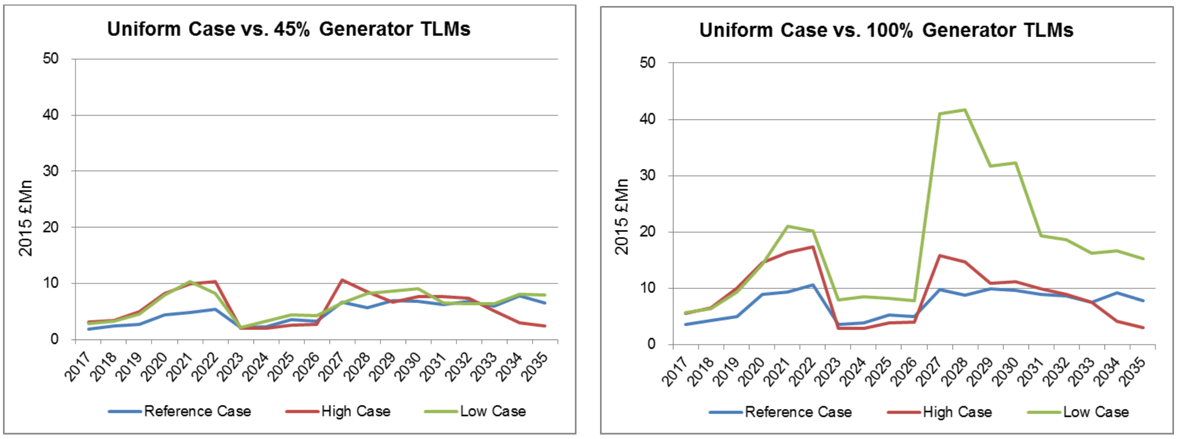
Source: NERA/Imperial

Figure 4.20
Composition of the Annual Saving in Power Sector Costs in NW Europe in the High Case: Uniform Case vs. 100% Generator TLMs (£Mn, Real 2015)



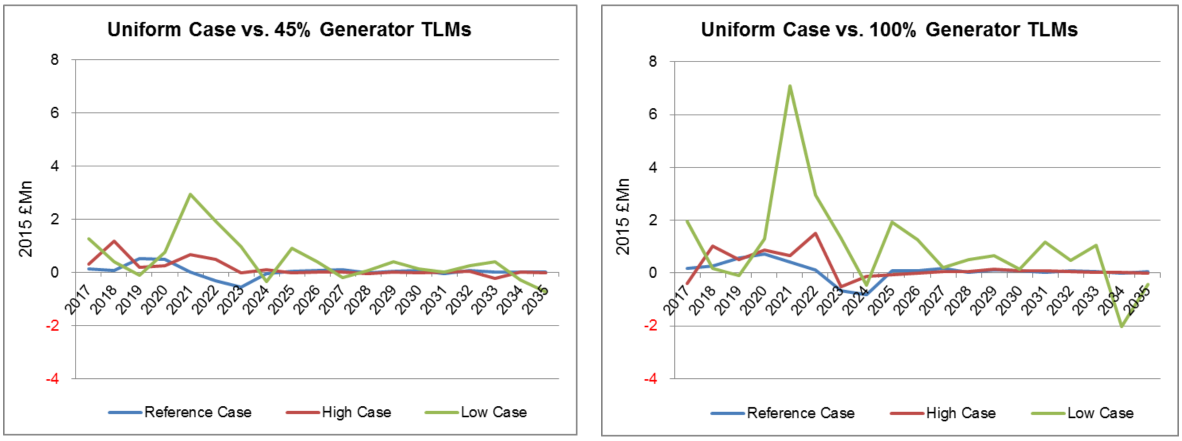
Source: NERA/Imperial

Figure 4.21
Saving in the Annual Cost of Transmission Losses in all Scenarios (£Mn, Real 2015)



Source: NERA/Imperial

Figure 4.22
Saving in Annual SO_2 and NOx Costs in all Scenarios (£Mn, Real 2015)



Source: NERA/Imperial

4.4.2. Changes in British power prices

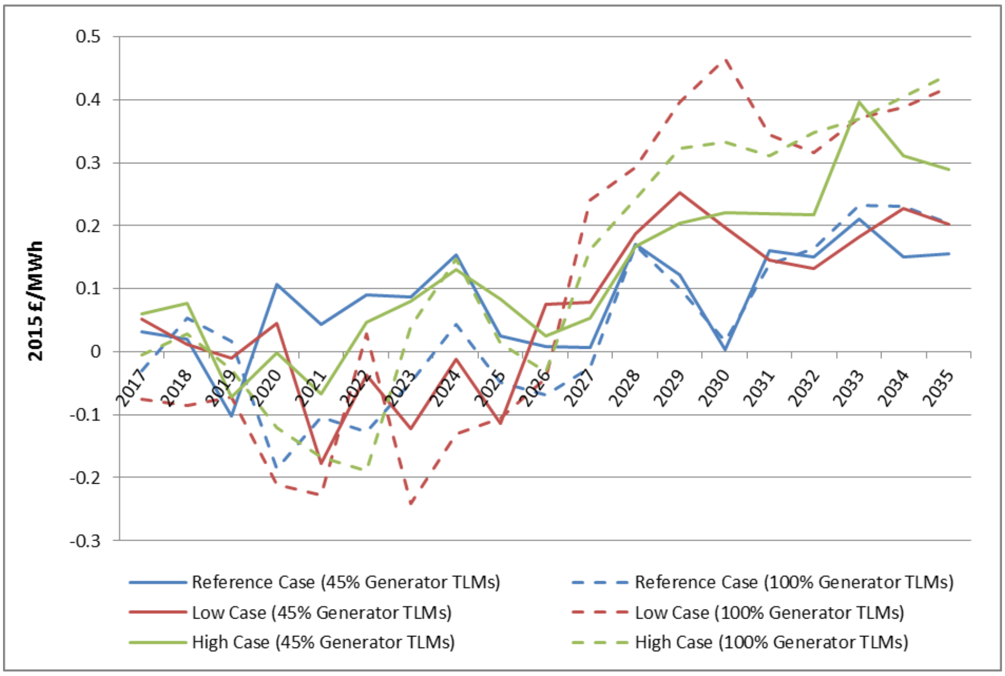
The figures below show the change (in £/MWh) in the annual baseload energy price predicted by our model from the use of locational transmission loss factors. As discussed above, there was no strong *a priori* reason to believe this policy would have a positive or a negative impact on wholesale prices. Some parts of the supply curve would shift upwards as a result of this policy, and some parts would shift down, resulting in no clear theoretical prediction as to whether power prices would rise or fall on average.

As Figure 4.23 shows, the policy tends to reduce wholesale energy power prices in the short-term, but increase them towards the end of the modelling horizon. However, the magnitude of the effect is extremely small in percentage terms. The maximum quantum of effect across all the scenarios in any year is £0.4/MWh, and in most years/scenarios the effect is less than

£0.2/MWh. This compares to a wholesale energy price that reaches between £70/MWh and £90/MWh, depending on the scenario (see Figure 4.7).

This change in the direction of the price effect is linked to the switching effect we see in Figure 4.12, Figure 4.13 and Figure 4.14. Our modelling suggests that the marginal plant that sets the hourly wholesale price is usually towards the south of Britain. This applies both in the short-term, when locations are defined primarily by the locations of existing plant, and in the longer-term, when our assumed TNUoS charges and other locational costs lead the model to develop most thermal plant towards the south of the country. As the modelled loss factors show, southern generators tend to gain in the short-term, leading them to have lower marginal production costs and to lower wholesale prices. In the longer-term the effect reverses, southern generators see higher costs from the policy and the effect of the policy is to raise wholesale prices.

Figure 4.23
Change in the Baseload Energy Price in all Scenarios (£/MWh, Real 2015)



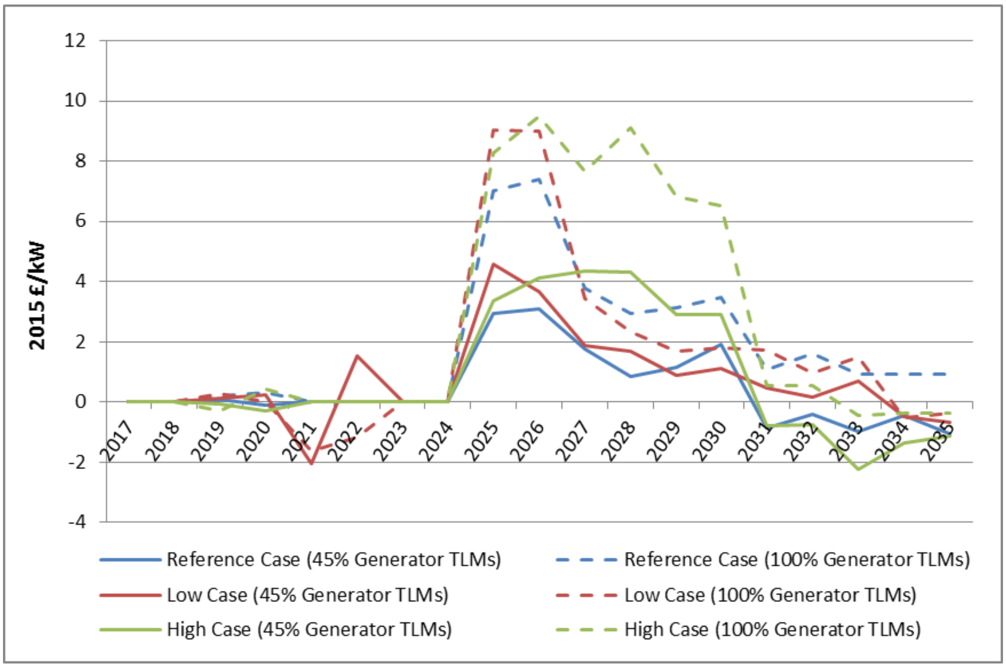
Source: NERA/Imperial

Figure 4.20 shows the annual change in the wholesale capacity price as a result of the policy. As the figure shows, capacity prices change by less than £2/kW/yr in most years, but we see a larger effect for a relatively short period of time in the late 2020s, when capacity prices tend to rise by between £2 and £10/kW/yr, depending on the scenario, with the largest effects in the scenarios where we assume a 100:0 G:D split.

Our modelling results (derived before modelling the effect of the policy – see Section 4.1 above) represent an economic equilibrium in which investors in the optimised mix of generation capacity are able to recover their fixed investment costs, the change in the capacity price therefore needs to reflect the change in the least profitable plant that is required in this least cost generation mix.

We would therefore expect to see a tendency for the change in capacity prices to offset the change in energy prices shown in Figure 4.23, because lower energy prices tend to leave more "missing money" to be recovered through the capacity market. However, it will not always be the case that the change in capacity price will offset the change in energy price, because lower *average* energy prices, as shown in Figure 4.23, do not necessarily imply that prices are lower at all times of the year, making it unclear whether the profits of the *marginal* plant required to meet the capacity requirement rises or falls as a result of the policy. The effect depends, amongst other things, on where the marginal plant is located.

Figure 4.24
Change in Capacity Market Price in all Scenarios (£/kW/yr, Real 2015)



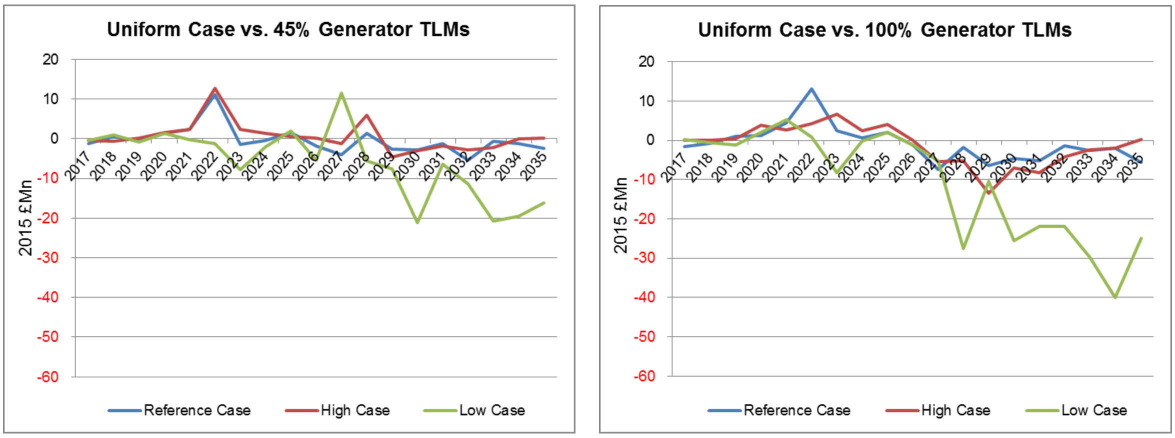
Source: NERA/Imperial

4.4.3. Changes in the net costs of imports/exports

As described above in Section 3.4, our model optimises despatch in the Irish market in the same way as in the British market, allowing us to examine the impact on trade between these markets, and the resulting effects on generation costs in the two jurisdictions. For instance, the policy affects British wholesale prices (see above), so we would expect to see changes in net imports, with the effect of increasing or decreasing generation costs within Britain. It is therefore important to account for changes in costs in other jurisdictions when considering the total estimated welfare improvement from the policy, and changes in the costs of net imports when assessing the effect of the policy on British consumers and producers.

The CMA's proposal to introduce zonal loss factors would not apply to the Irish market, and so the supply curve in Ireland would be unaffected. Hence, any changes in trade flows and generation costs in Ireland (shown in Figure 4.25) result from changes in the British wholesale price, and resulting changes in exports/imports. As the figure shows, higher power prices in Britain towards the end of the modelling horizon (see Figure 4.23) attract more imports into Britain from Ireland, which increases generation costs in the Irish market over this period. We see the reverse effect in the earlier part of the modelling horizon.

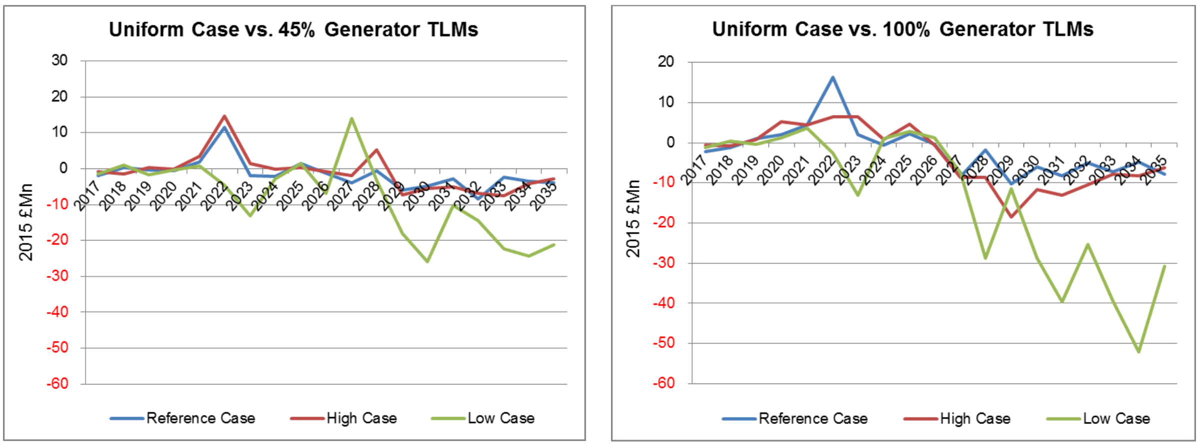
Figure 4.25
Saving in the Annual Costs of Generation in Ireland in all Scenarios (£Mn, Real 2015)



Source: NERA/Imperial

Figure 4.26 shows similar information, but instead of examining the change in net imports based on generation costs in Ireland, it values the change in net imports at prevailing market prices in order to assess the scale of transfers between jurisdictions. Specifically, we value trade flows by assuming that, in hours when Britain is importing, we assume Irish sellers "price up" to the British wholesale price when selling their power into Britain, and when Britain is exporting, British sellers price-up to the Irish price. As Figure 4.26 shows, we see a similar quantum and direction of effect using this metric to value changes in trade flows with Ireland.

Figure 4.26
Saving in the Annual Costs of Net Imports from Ireland in all Scenarios, Valued at Market Prices (£Mn, Real 2015)



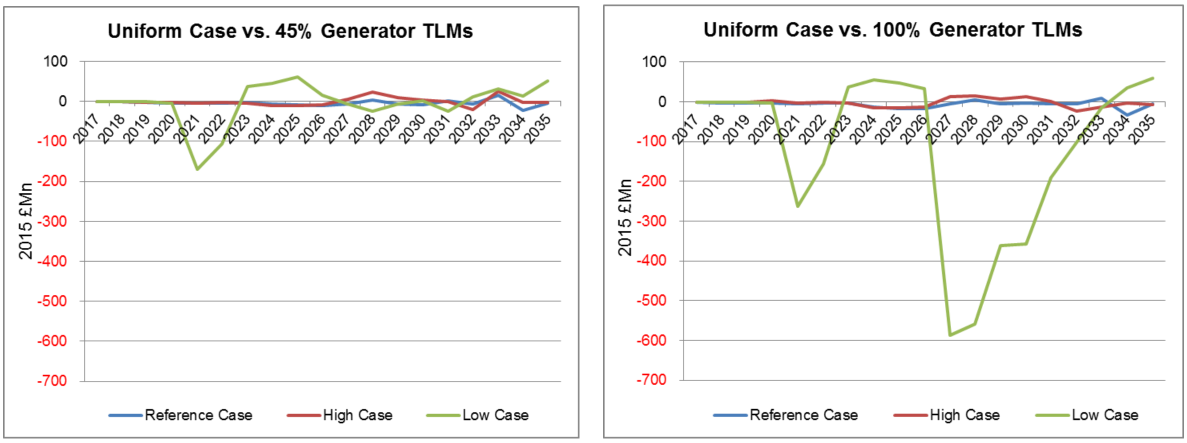
Source: NERA/Imperial

Figure 4.27 and Figure 4.28 show the same information in respect of changes in trade flows across the Continental European interconnectors. As described above in Section 3.4, it is not practical to model the whole European system in our model, so we assume Continental European interconnectors can be despatched at our assumed marginal cost of a gas-fired CCGT in these markets.[38]

As the figures show, we see a modest effect on the costs of net imports in the reference and high cases, both when we value trade flows based on the change in costs in neighbouring markets (ie. the marginal cost of a European CCGT) and when we value changes in cost at prevailing market prices. The effect in these scenarios is -£48 million and £80 million per annum.

However, the effect in the low case is markedly larger, especially in the scenario with the 100:0 G:D split, and in the late 2020s and early 2030s. The explanation for this result is that the policy causes more switching in the merit order between British and European thermal plant, and markedly more imports in some years. British and European thermal plant are closer in this scenario than the others because we assume the CPS rates are removed from 2016/17 onwards, which makes them closer in the merit order in this scenario than the others.

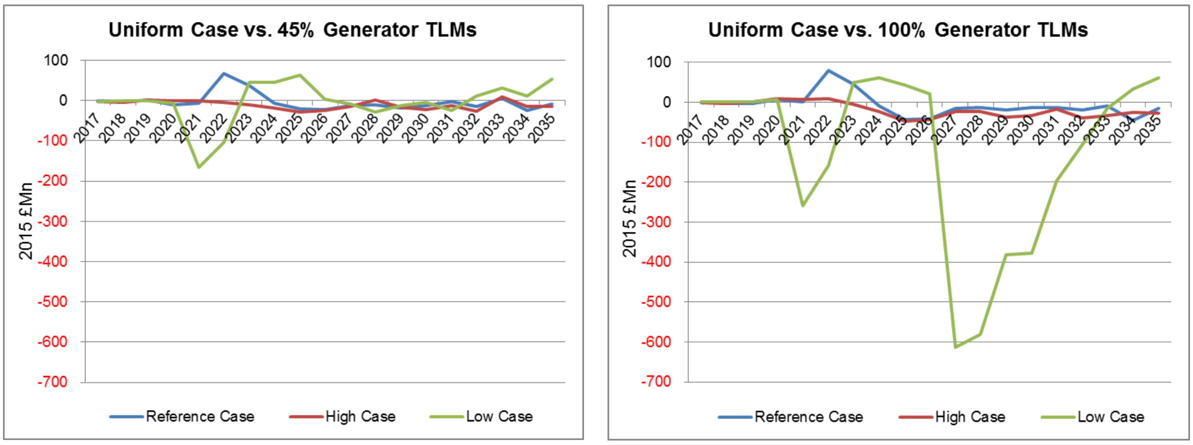
Figure 4.27
Saving in the Annual Costs of Generation in Continental Europe in all Scenarios (£Mn, Real 2015)



Source: NERA/Imperial

38 As discussed above, this marginal cost estimate assumes these generators face the EU ETS price but do not pay the UK government's carbon tax (ie. Carbon Price Support).

Figure 4.28
Saving in the Annual Costs of Net Imports from Continental Europe in all Scenarios, Valued at Market Prices (£Mn, Real 2015)



Source: NERA/Imperial

4.4.4. The present value of changes in costs

Table 4.1 shows the estimated change in costs arising from the proposed policy in net present value terms for the period 2017-2035.[39] Each column corresponds to a scenario on commodity prices and the G:D split, and we adopt the convention of showing reductions in costs as a result of the policy as positive numbers (shown in black font), and increases in costs from the policy as negative numbers (shown in red font).

Consistent with the annual impact on transmission losses, the first row of the table shows that the modelled reduction in losses is higher in the 100:0 G:D split cases as the loss multipliers send a less diluted marginal signal to generators. The saving is between £62 million and £235 million over the period to 2035.

The next several rows of the table show changes in generation costs (fuel, variable O&M and CO_2) within the British market. Depending on the scenario, the modelled effect on these costs ranges between a reduction of £1,620 million and an increase of -£17 million. As noted in Section 4.3 above, on the face of it this is a surprising result, as we would expect savings in losses to be somewhat offset by higher generation costs. However, a large part of these effects results from changes in the volume of imports changing the amount of production that takes place in Britain.

As a measure of the total welfare arising from the policy, we need to factor in the change in costs that arise in other jurisdictions, shown further down the table. Specifically, the

39 All of our CBA calculations are conducted on the assumption that the new transmission loss mechanism is implemented from 1 January 2017, and we compute the impact on costs, etc., over the period to the end of 2035. We discount future costs using the social time preference rate specified in the HMT "Green Book" of 3.5% (real). Note, however, that when we annuitise the fixed costs incurred by private investors we use market discount rates based on the cost of capital relevant to the applicable investments. For instance, we annuitise generation capital costs at a Weighted Average Cost of Capital applicable to private power generation investors.

modelling shows that modelled generation costs across all geographies rise by between £8 million and £79 million.

The costs of constraint management, computed in DTIM, are also systematically lower with zonal transmission losses. The reason for this is that changes in constraint costs tend to be correlated with changes in losses. Plants that are disadvantaged by zonal losses are those whose output has to be transported for long distances to meet load. Plants located a long way from load centres are also likely to be those who impose the highest investment and constraint costs on the transmission system, so by reducing output from those plants the model also identifies a saving in constraint costs of between £150 million and £206 million.

The table also shows the change in SO_2 and NOx costs from the policy, which are relatively small at up to £16 million.

Overall, our model predicts material savings in costs across all scenarios, amounting to between £53 million and £282 million in present value terms. This effect is driven by lower losses, constraint costs and generation costs from GB producers, albeit slightly offset by increases in net import costs from Ireland and Continental Europe. This aggregate effect, intended to represent the change in welfare from a British perspective, values changes in net imports at market prices, which are also shown in the table. However, the table values the change in net imports at both prevailing market prices (row 9) and based on the change in costs in other jurisdictions (row 12).

Table 4.1
Benefit of Introducing Zonal TLMs on Power Sector Costs, 2017 - 2035 (Real 2015 £m)

	Fundamentals Scenario		Reference Scenario		High Commodity Prices Scenario		Low Commodity Prices Scenario	
	G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
	Changes in Power Sector Costs							
1	Change in Cost of Transmission Losses	£Mn	62.85	97.79	78.07	124.90	83.41	235.00
2	Total Change in Generation Costs in GB	£Mn	46.26	53.19	-17.45	2.75	153.77	1,620.46
3	*Change in Fuel Costs*	*£Mn*	*40.97*	*48.37*	*-18.25*	*-6.19*	*120.59*	*1,395.28*
4	*Change in Generation Variable O&M Costs*	*£Mn*	*-4.66*	*-10.48*	*-7.15*	*-14.75*	*8.50*	*52.81*
5	*Change in Generation CO2 Costs*	*£Mn*	*9.95*	*15.30*	*7.95*	*23.69*	*24.67*	*172.36*
6	Total Change in SO2 and NOX Costs in GB	£Mn	0.58	1.30	2.69	3.32	7.70	15.67
7	Change in Cost of Constraint Management	£Mn	150.06	158.67	166.08	179.95	181.24	206.37
8	**Total Change in Costs within GB**	£Mn	259.75	310.95	229.39	310.91	426.12	2,077.49
9	Total Change in Net Import Cost (imports @ GB market prices)	£Mn	-44.81	-75.32	-142.56	-255.04	-202.18	-1,779.97
10	*Change in Net Import Cost - Ireland*	*£Mn*	*-16.47*	*-16.15*	*-7.34*	*-34.60*	*-93.08*	*-158.57*
11	*Change in Net Import Cost - Europe*	*£Mn*	*-28.34*	*-59.17*	*-135.22*	*-220.43*	*-109.11*	*-1,621.40*
12	Change in Generation Costs in Other Jurisdictions	£Mn	-55.14	-80.49	2.34	-40.65	-163.07	-1,699.72
13	*Change in Other Generation Cost - Ireland*	*£Mn*	*-1.79*	*-5.01*	*10.97*	*-9.81*	*-64.39*	*-121.26*
14	*Change in Other Generation Cost - Europe*	*£Mn*	*-53.35*	*-75.48*	*-8.63*	*-30.84*	*-98.69*	*-1,578.46*
15	**Total Change in Generation Costs in NW Europe**	£Mn	204.02	229.17	229.05	266.95	255.34	362.10
16	*Change in Generator Fuel, CO2 and VOM in NW Europe*	*£Mn*	*-8.88*	*-27.30*	*-15.11*	*-37.90*	*-9.31*	*-79.27*
17	*Change in Cost of Transmission Losses*	*£Mn*	*62.85*	*97.79*	*78.07*	*124.90*	*83.41*	*235.00*
18	*Change in Cost of Constraint Management*	*£Mn*	*150.06*	*158.67*	*166.08*	*179.95*	*181.24*	*206.37*
19	**Total Change in Generation Costs to GB**	£Mn	214.35	234.34	84.14	52.56	216.23	281.85

Source: NERA/Imperial. Note: the "Total Change in Generation Costs to GB" in row 19 is the sum of rows 1, 2, 7, and 9.

Given the challenge of forecasting the location of investment decisions, which are potentially sensitive to the assumptions we make about long-term TNUoS charges, Table 4.2 shows the effect for the earlier period of the modelling horizon to 2026. As described above, the results we obtain for this period are less likely to be influenced by the locational assumptions we make for new plant, which are linked to the "switching" in loss factors between the north and south (see Section 4.2). Table 4.3 shows the results for the later period, such that the sum of the results shown in Table 4.2 and Table 4.3 equal the aggregate effect shown in Table 4.1.

Table 4.2 shows that the aggregate savings range between £97 million and £246 million. In the later period, Table 4.3 shows that the effect ranges from *negative* £69 million (ie a detriment of the policy) to £77 million. These numbers are of a smaller magnitude than those shown in Table 4.2 for the earlier part of the modelling horizon, as they are discounted to 2017.

As discussed above, we would expect the overall welfare effects of the policy to be positive, when we measure welfare by the change in generation costs. This does not necessarily hold when we measure changes in welfare in a way that values imports at market prices. Specifically, the policy increases British power prices in some years, which increases the cost of procuring imports that we assume traders in neighbouring markets sell into Britain at the market clearing price. For this reason, some of the overall results shown in row 19 of Table 4.3 indicate an overall negative effect of the policy for the later part of the modelling horizon.

Table 4.2
Benefit of Introducing Zonal TLMs on Power Sector Costs, 2017 - 2026 (Real 2015 £m)

	Fundamentals Scenario		Reference Scenario		High Commodity Prices Scenario		Low Commodity Prices Scenario	
	G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
	Changes in Power Sector Costs							
1	Change in Cost of Transmission Losses	£Mn	27.28	49.45	41.54	71.42	42.73	90.85
2	Total Change in Generation Costs in GB	£Mn	15.89	12.66	11.10	-6.91	123.49	197.83
3	*Change in Fuel Costs*	*£Mn*	*16.19*	*14.67*	*3.32*	*-12.48*	*92.73*	*144.88*
4	*Change in Generation Variable O&M Costs*	*£Mn*	*-5.27*	*-9.41*	*-8.27*	*-9.35*	*7.41*	*13.07*
5	*Change in Generation CO2 Costs*	*£Mn*	*4.97*	*7.40*	*16.05*	*14.91*	*23.35*	*39.88*
6	Total Change in SO2 and NOX Costs in GB	£Mn	0.44	0.92	2.81	2.99	7.61	14.44
7	Change in Cost of Constraint Management	£Mn	124.44	128.11	100.96	103.16	120.21	125.65
8	**Total Change in Costs within GB**	£Mn	168.05	191.16	156.40	170.66	294.03	428.77
9	Total Change in Net Import Cost (imports @ GB market prices)	£Mn	37.21	56.13	-56.13	-46.16	-138.04	-209.48
10	*Change in Net Import Cost - Ireland*	*£Mn*	*5.26*	*19.61*	*13.40*	*21.87*	*-22.03*	*-5.30*
11	*Change in Net Import Cost - Europe*	*£Mn*	*31.95*	*36.52*	*-69.53*	*-68.03*	*-116.00*	*-204.18*
12	Change in Generation Costs in Other Jurisdictions	£Mn	-23.27	-32.21	-19.45	-16.61	-127.38	-224.29
13	*Change in Other Generation Cost - Ireland*	*£Mn*	*9.45*	*17.38*	*16.42*	*19.80*	*-10.02*	*-0.26*
14	*Change in Other Generation Cost - Europe*	*£Mn*	*-32.72*	*-49.59*	*-35.86*	*-36.41*	*-117.36*	*-224.03*
15	**Total Change in Generation Costs in NW Europe**	£Mn	144.35	158.02	134.14	151.06	159.04	190.04
16	*Change in Generator Fuel, CO2 and VOM in NW Europe*	*£Mn*	*-7.37*	*-19.55*	*-8.35*	*-23.52*	*-3.90*	*-26.46*
17	*Change in Cost of Transmission Losses*	*£Mn*	*27.28*	*49.45*	*41.54*	*71.42*	*42.73*	*90.85*
18	*Change in Cost of Constraint Management*	*£Mn*	*124.44*	*128.11*	*100.96*	*103.16*	*120.21*	*125.65*
19	**Total Change in Generation Costs to GB**	£Mn	204.83	246.36	97.46	121.50	148.38	204.85

Source: NERA/Imperial

Table 4.3
Benefit of Introducing Zonal TLMs on Power Sector Costs, 2027 - 2035 (Real 2015 £m)

	Fundamentals Scenario		Reference Scenario		High Commodity Prices Scenario		Low Commodity Prices Scenario	
	G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
	Changes in Power Sector Costs							
1	Change in Cost of Transmission Losses	£Mn	35.56	48.34	36.54	53.47	40.69	144.15
2	Total Change in Generation Costs in GB	£Mn	30.37	40.53	-28.55	9.66	30.28	1,422.63
3	*Change in Fuel Costs*	*£Mn*	24.78	33.69	-21.57	6.29	27.86	1,250.40
4	*Change in Generation Variable O&M Costs*	*£Mn*	0.61	-1.07	1.12	-5.40	1.09	39.74
5	*Change in Generation CO2 Costs*	*£Mn*	4.98	7.91	-8.10	8.78	1.33	132.48
6	Total Change in SO2 and NOX Costs in GB	£Mn	0.14	0.37	-0.12	0.32	0.09	1.23
7	Change in Cost of Constraint Management	£Mn	25.62	30.56	65.13	76.79	61.03	80.72
8	**Total Change in Costs within GB**	£Mn	91.69	119.80	72.99	140.25	132.09	1,648.73
9	Total Change in Net Import Cost (imports @ GB market prices)	£Mn	-82.03	-131.45	-86.43	-208.87	-64.15	-1,570.50
10	*Change in Net Import Cost - Ireland*	*£Mn*	-21.73	-35.77	-20.75	-56.47	-71.04	-153.28
11	*Change in Net Import Cost - Europe*	*£Mn*	-60.29	-95.68	-65.69	-152.40	6.90	-1,417.22
12	Change in Generation Costs in Other Jurisdictions	£Mn	-31.88	-48.27	21.79	-24.04	-35.69	-1,475.43
13	*Change in Other Generation Cost - Ireland*	*£Mn*	-11.24	-22.39	-5.44	-29.61	-54.37	-121.00
14	*Change in Other Generation Cost - Europe*	*£Mn*	-20.63	-25.88	27.24	5.57	18.68	-1,354.43
15	**Total Change in Generation Costs in NW Europe**	£Mn	59.67	71.15	94.90	115.89	96.31	172.06
16	*Change in Generator Fuel, CO2 and VOM in NW Europe*	*£Mn*	-1.51	-7.74	-6.76	-14.37	-5.41	-52.81
17	*Change in Cost of Transmission Losses*	*£Mn*	35.56	48.34	36.54	53.47	40.69	144.15
18	*Change in Cost of Constraint Management*	*£Mn*	25.62	30.56	65.13	76.79	61.03	80.72
19	**Total Change in Generation Costs to GB**	£Mn	9.52	-12.02	-13.32	-68.94	67.85	77.00

Source: NERA/Imperial

4.5. The Impact on Consumer Bills

4.5.1. Breakdown of annual changes in consumer bills

The figures below show a decomposition of the change in annual consumer bills from applying zonal loss factors across all the modelled scenarios. The figures also show the decomposition of consumer bill reduction into the following effects, and that the effect on consumer bills is dominated by changes in wholesale energy and capacity prices:

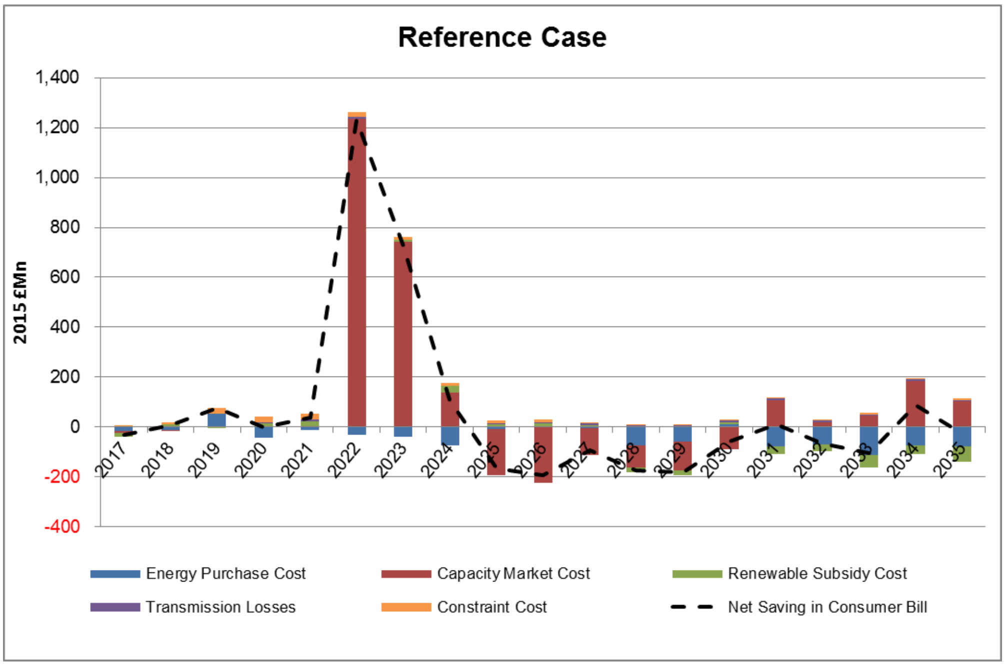
- Across all scenarios, energy market costs are higher for most of the modelling horizon as a result of higher wholesale prices shown in Figure 4.23;
- With the exception of the reference case, consumers see marked increases in capacity market costs, particularly in the period 2025-2030, which reflects higher capacity prices during the same period, as shown in Figure 4.24. The change in capacity market costs also tends to be larger in the 100:0 G:D split cases compared with the 45:55 cases. By contrast, consumers see a reduction in capacity costs in the reference case, such that it offsets the increase in energy procurement costs;
- The costs of subsidies paid to low carbon generation are lower in the first half over the modelling horizon and higher in the second half. This change in subsidy costs arises because the revenues earned by generators supported through the CFD FIT mechanism from the sale of their output into the market, and thus their need for subsidy, changes as a result of the policy. Higher energy prices would tend to increase the profits of these supported generators and reduce their need for subsidy, and vice versa. Also, if supported

generators tend to be in parts of the country where zonal loss factors impose an additional cost, they would tend to make less profit and require greater subsidy, and vice versa.

Overall, as Figure 4.29, Figure 4.30 and Figure 4.31 show for the scenarios with a 45:55 G:D split, we find modelled reductions in consumer bills in most years in the reference scenario and modelled increases in consumer bills in the majority of years in the low and high scenarios. The modelled effects are similar in the 100:0 G:D split cases, as Figure 4.32, Figure 4.33 and Figure 4.34 show.

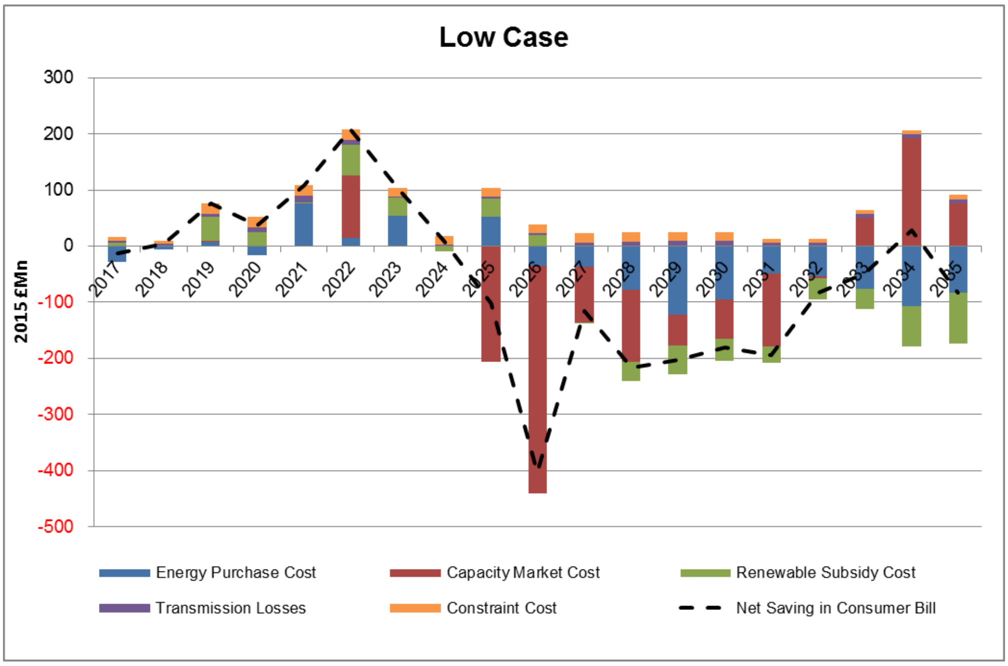
Modelled reductions in transmission losses and constraint costs, which we assume are passed onto consumers, reduce consumer bills, but the effects are small in magnitude compared to the effects on wholesale procurement costs.

Figure 4.29
Composition of the Annual Saving in Consumer Bills in the Reference Case: Uniform Case vs. 45% Generator TLMs (£Mn, Real 2015)



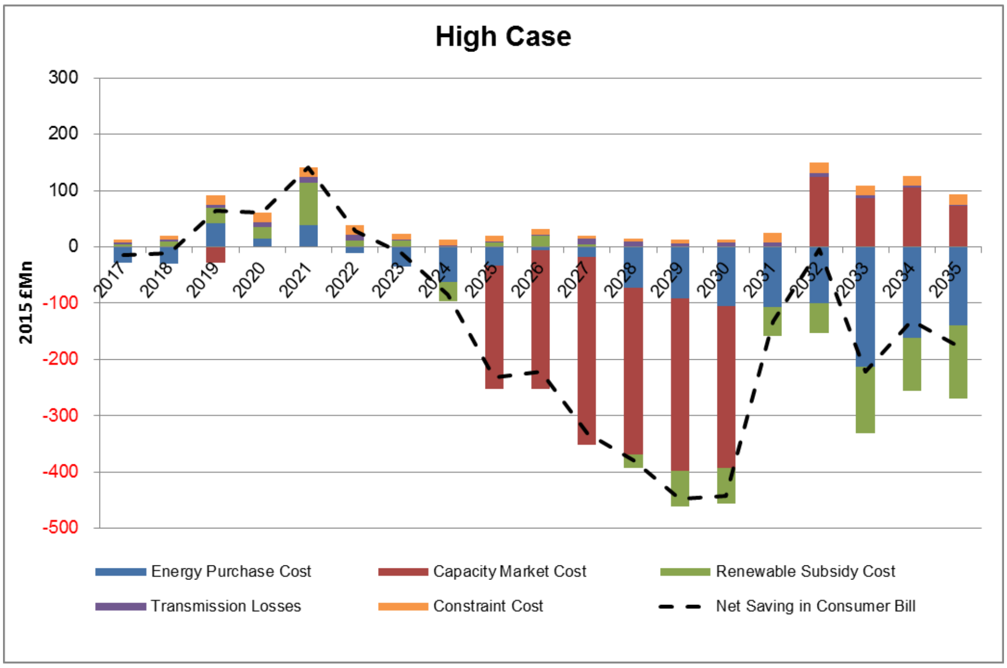
Source: NERA/Imperial

Figure 4.30
Composition of the Annual Saving in Consumer Bills in the Low Case: Uniform Case vs. 45% Generator TLMs (£Mn, Real 2015)



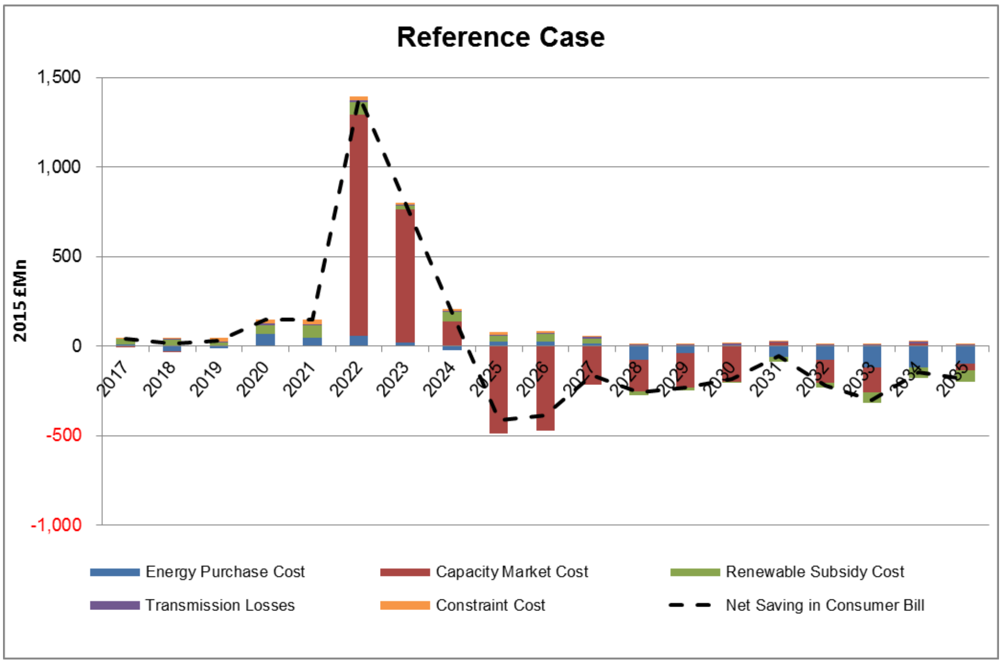
Source: NERA/Imperial

Figure 4.31
Composition of the Annual Saving in Consumer Bills in the High Case: Uniform Case vs. 45% Generator TLMs (£Mn, Real 2015)



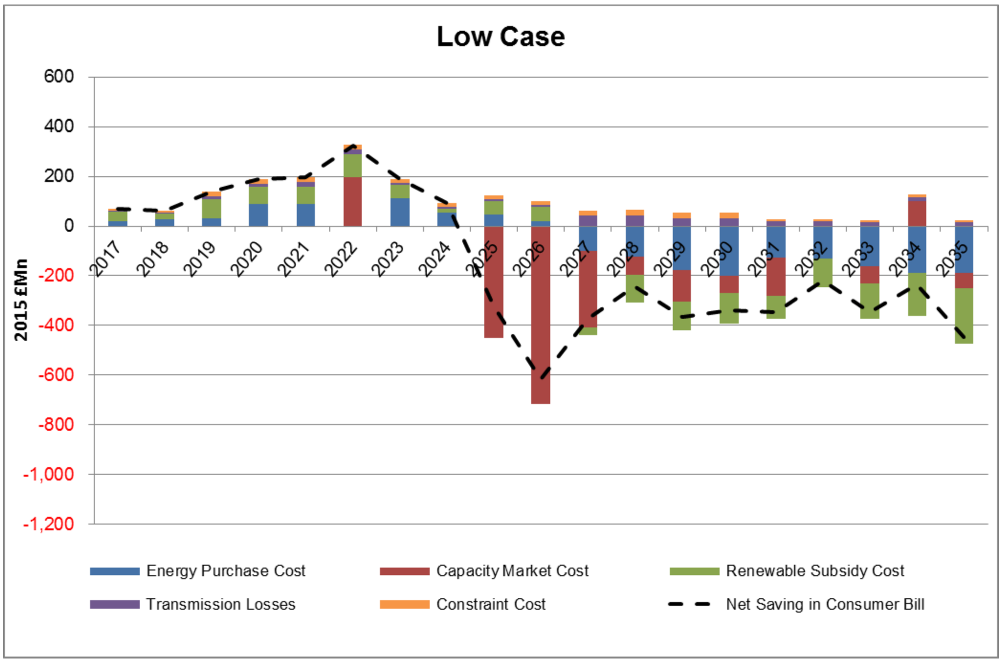
Source: NERA/Imperial

Figure 4.32
Composition of the Annual Saving in Consumer Bills in the Reference Case: Uniform Case vs. 100% Generator TLMs (£Mn, Real 2015)



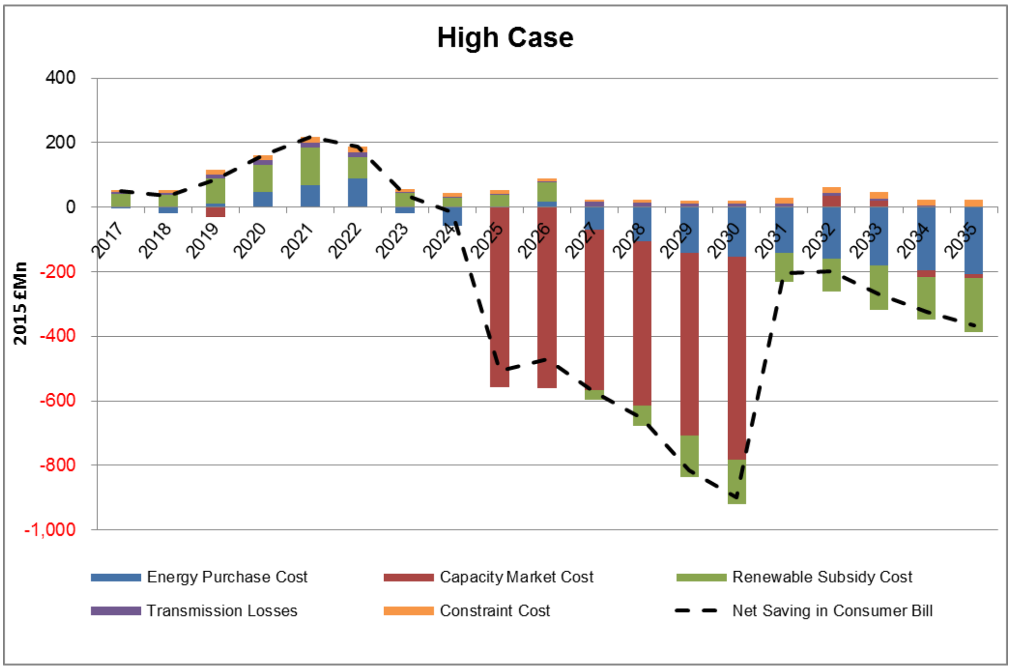
Source: NERA/Imperial

Figure 4.33
Composition of the Annual Saving in Consumer Bills in the Low Case: Uniform Case vs. 100% Generator TLMs (£Mn, Real 2015)



Source: NERA/Imperial

Figure 4.34
Composition of the Annual Saving in Consumer Bills in the High Case: Uniform Case vs. 100% Generator TLMs (£Mn, Real 2015)



Source: NERA/Imperial

4.5.2. The present value of changes in consumer bills

Table 4.4 shows the modelled change in consumer bills as a result of the policy in net present value terms for the entire modelling period. As before, positive numbers in black font indicate a benefit of the policy, or a reduction in bills, and negative numbers in red font indicate an increase in consumer bills.

Consistent with our annual results as described in the previous section, the effect of changes in wholesale procurement costs outweighs the other effects. Lower wholesale procurement costs in the reference case lead to an overall reduction in consumer bills of between £1,223 million and £530 million in the 45:55 and 100:0 G:D split cases, and bills rise by between £593 million and £2,955 million in the other scenarios.

Table 4.4
Benefit of Introducing Zonal TLMs on Consumer Bills, 2017 - 2035 (Real 2015 £m)

Fundamentals Scenario		**Reference Scenario**		**High Commodity Prices Scenario**		**Low Commodity Prices Scenario**	
G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
Changes in Consumer Bills							
Change in Wholesale Purchase Costs	£Mn	924.27	171.31	-1,611.83	-2,925.93	-812.74	-1,598.64
Change in Energy Purchase Costs	*£Mn*	*-457.51*	*-172.30*	*-669.52*	*-678.84*	*-327.09*	*-429.60*
Change in Capacity Market Costs	*£Mn*	*1,381.78*	*343.60*	*-942.30*	*-2,247.08*	*-485.65*	*-1,169.05*
Change in Renewable Subsidy Costs	£Mn	85.45	102.54	-240.46	-334.00	-44.40	-198.83
Change in Cost of Transmission Losses	£Mn	62.85	97.79	78.07	124.90	83.41	235.00
Change in Cost of Constraint Management	£Mn	150.06	158.67	166.08	179.95	181.24	206.37
Total Aggregate Change in Consumer Bills	£Mn	1,222.62	530.31	-1,608.13	-2,955.07	-592.50	-1,356.11

Source: NERA/Imperial

As before, given the greater certainty we can attach to results in the earlier part of the modelling horizon, Table 4.5 and Table 4.6 decompose the modelled change in consumer bills into the periods 2017-26 and 2027-35, such that the numbers presented in these tables sum to those shown in Table 4.4.

Table 4.5
Benefit of Introducing Zonal TLMs on Consumer Bills, 2017 - 2026 (Real 2015 £m)

Fundamentals Scenario		**Reference Scenario**		**High Commodity Prices Scenario**		**Low Commodity Prices Scenario**	
G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
Changes in Consumer Bills							
Change in Wholesale Purchase Costs	£Mn	1,248.14	1,151.30	-445.48	-720.44	-254.78	-277.33
Change in Energy Purchase Costs	*£Mn*	*-146.44*	*150.74*	*-84.88*	*114.02*	*90.96*	*398.99*
Change in Capacity Market Costs	*£Mn*	*1,394.57*	*1,000.56*	*-360.60*	*-834.46*	*-345.74*	*-676.31*
Change in Renewable Subsidy Costs	£Mn	160.77	308.91	102.18	331.33	130.11	339.63
Change in Cost of Transmission Losses	£Mn	27.28	49.45	41.54	71.42	42.73	90.85
Change in Cost of Constraint Management	£Mn	124.44	128.11	100.96	103.16	120.21	125.65
Total Aggregate Change in Consumer Bills	£Mn	1,560.63	1,637.78	-200.81	-214.53	38.26	278.80

Source: NERA/Imperial

Table 4.6
Benefit of Introducing Zonal TLMs on Consumer Bills, 2027 - 2035 (Real 2015 £m)

Fundamentals Scenario		Reference Scenario		High Commodity Prices Scenario		Low Commodity Prices Scenario	
G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
Changes in Consumer Bills							
Change in Wholesale Purchase Costs	£Mn	-323.87	-980.00	-1,166.35	-2,205.48	-557.96	-1,321.32
Change in Energy Purchase Costs	*£Mn*	-311.07	-323.03	-584.64	-792.86	-418.05	-828.58
Change in Capacity Market Costs	*£Mn*	-12.80	-656.96	-581.71	-1,412.62	-139.91	-492.73
Change in Renewable Subsidy Costs	£Mn	-75.33	-206.37	-342.64	-665.33	-174.51	-538.46
Change in Cost of Transmission Losses	£Mn	35.56	48.34	36.54	53.47	40.69	144.15
Change in Cost of Constraint Management	£Mn	25.62	30.56	65.13	76.79	61.03	80.72
Total Aggregate Change in Consumer Bills	£Mn	-338.02	-1,107.47	-1,407.32	-2,740.55	-630.75	-1,634.91

Source: NERA/Imperial

4.6. Regional Effects of the Policy

As well as the national average change in consumer bills that results from introducing zonal TLMs, as shown above in Section 4.5, we also estimate the distributional impact of the policy amongst consumers. Table 4.7 shows how the change in consumer bills varies across the country, and we also decompose this result into the periods 2017-26 and 2027-35 in Table 4.8 and Table 4.9.

As described above, the change in national wholesale prices tends to be the dominant driver of our modelled change in average consumer bills. Similarly, this effect tends to dominate regional variation in the effect of the policy. For instance, in the period 2017-26, the modelling suggests that consumers will benefit from the policy on average in the reference scenario. Table 4.8 shows that consumers in Scotland will benefit by more than consumers in the south, given that the zonal TLMs applied to their consumption would reduce their costs (see Section 4.2). However, in the low and high cases, consumers all see higher bills, with consumers in Scotland seeing less of an increase than those in the south.

Table 4.7, Table 4.8 and Table 4.9 also show the distribution of effects amongst the major generation companies, based on a mapping of plants to owners provided to us by the CMA. Some of the “big six” generation companies tend to gain more (or lose less) than others reflecting the concentrations of their plant in different parts of the country. However, as for our estimated differences in consumer bills across different parts of the country, the distributional effects tend to be masked by the changes in prices that mean all generators tend to win or lose as a result of the policy.

Overall, therefore, while our modelling has consistently identified savings in cost as a result of introducing zonal loss factors, the distributional effects between and amongst British producers and consumers are volatile, and appear very sensitive to changes in fundamental assumptions. This conclusion stems from the uncertain impact of the policy on the marginal units that tend to set the price in the energy and capacity markets, which could be positive or negative, and can have potentially large effects on prices.

Table 4.7
Distribution of Average Saving in Consumer Bills and Generator Margins, 2017 - 2035 (Real 2015 £m)

Fundamentals Scenario		Reference Scenario		High Commodity Prices Scenario		Low Commodity Prices Scenario	
G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
Distributional Effects							
Change in Customer Bill: National Average	£/yr	0.76	0.33	-1.00	-1.85	-0.37	-0.85
Change in Customer Bill in North Scotland	£/yr	-0.53	-0.96	-1.58	-2.42	-1.15	-1.63
Change in Customer Bill in South Scotland	£/yr	-0.17	-0.60	-1.05	-1.89	-0.76	-1.24
Change in Customer Bill in North England/Wales	£/yr	0.50	0.07	-0.11	-0.95	-0.01	-0.49
Change in Customer Bill in Midlands of England/Wales	£/yr	0.33	-0.10	-1.86	-2.70	-1.34	-1.82
Change in Customer Bill in South England/Wales	£/yr	1.09	0.66	-1.17	-2.01	-0.23	-0.71
Changes in Generator Margins							
Changes in Generator Margin: National Total	£Mn	-682.79	121.89	1,175.65	2,510.85	685.92	1,857.00
Change in Generator Margins in North Scotland	£Mn	-55.86	-83.77	-4.11	-11.19	-15.61	-32.39
Change in Generator Margins in South Scotland	£Mn	-18.13	-21.83	14.88	26.62	8.24	15.86
Change in Generator Margins in North England/Wales	£Mn	-122.40	-86.68	328.78	667.52	197.58	475.46
Change in Generator Margins in Midlands of England/Wales	£Mn	-315.82	-183.16	210.18	454.51	52.34	217.35
Change in Generator Margins in South England/Wales	£Mn	-170.58	497.31	625.93	1,373.39	443.37	1,180.72
Change in Generator Margins by Centrica	£Mn	-83.81	-52.11	47.77	106.07	37.68	90.60
Change in Generator Margins by EDF	£Mn	-242.23	-256.16	64.03	112.18	24.44	73.16
Change in Generator Margins by EON	£Mn	-36.82	7.40	52.58	112.50	40.47	97.91
Change in Generator Margins by RWE	£Mn	-79.74	8.92	103.13	244.18	84.87	217.24
Change in Generator Margins by Scottish Power	£Mn	-23.78	-1.24	37.54	76.95	26.32	53.65
Change in Generator Margins by SSE	£Mn	-36.14	8.35	81.73	164.21	63.80	139.70
Change in Generator Margins for Other Players	£Mn	-180.26	406.72	788.88	1,694.76	408.34	1,184.75

Source: NERA/Imperial

Table 4.8
Distribution of Average Saving in Consumer Bills and Generator Margins, 2017 - 2026 (Real 2015 £m)

Fundamentals Scenario		Reference Scenario		High Commodity Prices Scenario		Low Commodity Prices Scenario	
G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
Distributional Effects							
Change in Customer Bill: National Average	£/yr	1.69	1.77	-0.22	-0.23	0.04	0.30
Change in Customer Bill in North Scotland	£/yr	2.57	2.66	0.77	0.75	1.08	1.34
Change in Customer Bill in South Scotland	£/yr	1.69	1.77	-0.22	-0.23	0.04	0.30
Change in Customer Bill in North England/Wales	£/yr	0.43	0.51	-1.27	-1.29	-1.12	-0.86
Change in Customer Bill in Midlands of England/Wales	£/yr	1.02	1.10	-0.51	-0.53	-0.39	-0.13
Change in Customer Bill in South England/Wales	£/yr	0.70	0.79	-0.94	-0.96	-0.80	-0.54
Changes in Generator Margins							
Changes in Generator Margin: National Total	£Mn	-897.87	-705.89	312.55	660.80	337.57	719.50
Change in Generator Margins in North Scotland	£Mn	-54.13	-86.70	-26.55	-56.70	-25.27	-55.68
Change in Generator Margins in South Scotland	£Mn	-17.91	-24.16	-4.42	-11.42	-4.66	-12.50
Change in Generator Margins in North England/Wales	£Mn	-219.92	-330.73	-32.77	-103.97	-53.95	-133.29
Change in Generator Margins in Midlands of England/Wales	£Mn	-417.13	-469.51	-31.59	-55.51	-77.59	-167.32
Change in Generator Margins in South England/Wales	£Mn	-188.78	205.21	407.89	888.40	499.04	1,088.29
Change in Generator Margins by Centrica	£Mn	-88.07	-71.54	24.98	58.53	30.32	70.25
Change in Generator Margins by EDF	£Mn	-255.01	-293.56	17.11	10.98	-3.58	-10.47
Change in Generator Margins by EON	£Mn	-37.54	-4.59	39.31	84.09	42.32	97.90
Change in Generator Margins by RWE	£Mn	-82.98	-28.23	67.91	161.40	81.11	187.92
Change in Generator Margins by Scottish Power	£Mn	-27.90	-13.66	16.79	37.21	16.86	35.40
Change in Generator Margins by SSE	£Mn	-47.59	-26.05	36.60	75.46	41.96	89.19
Change in Generator Margins for Other Players	£Mn	-358.78	-268.27	109.85	233.12	128.58	249.30

Source: NERA/Imperial

Table 4.9
Distribution of Average Saving in Consumer Bills and Generator Margins, 2027 - 2035 (Real 2015 £m)

Fundamentals Scenario		**Reference Scenario**		**High Commodity Prices Scenario**		**Low Commodity Prices Scenario**	
G:D Split		45/55	100/0	45/55	100/0	45/55	100/0
Distributional Effects							
Change in Customer Bill: National Average	£/yr	-0.93	-1.44	-0.79	-1.61	-0.41	-1.15
Change in Customer Bill in North Scotland	*£/yr*	*-3.11*	*-3.62*	*-2.34*	*-3.17*	*-2.23*	*-2.97*
Change in Customer Bill in South Scotland	*£/yr*	*-1.86*	*-2.38*	*-0.83*	*-1.66*	*-0.80*	*-1.54*
Change in Customer Bill in North England/Wales	*£/yr*	*0.07*	*-0.44*	*1.17*	*0.34*	*1.11*	*0.38*
Change in Customer Bill in Midlands of England/Wales	*£/yr*	*-0.68*	*-1.20*	*-1.35*	*-2.18*	*-0.96*	*-1.69*
Change in Customer Bill in South England/Wales	*£/yr*	*0.39*	*-0.13*	*-0.23*	*-1.05*	*0.57*	*-0.17*
Changes in Generator Margins							
Changes in Generator Margin: National Total	£Mn	215.08	827.78	863.09	1,850.05	348.35	1,137.50
Change in Generator Margins in North Scotland	*£Mn*	-1.73	2.93	22.44	45.51	9.66	23.29
Change in Generator Margins in South Scotland	*£Mn*	-0.22	2.33	19.31	38.04	12.90	28.36
Change in Generator Margins in North England/Wales	*£Mn*	97.52	244.06	361.55	771.48	251.53	608.74
Change in Generator Margins in Midlands of England/Wales	*£Mn*	101.31	286.35	241.77	510.03	129.93	384.67
Change in Generator Margins in South England/Wales	*£Mn*	18.20	292.10	218.04	484.99	-55.67	92.43
Change in Generator Margins by Centrica	*£Mn*	4.27	19.43	22.79	47.54	7.35	20.34
Change in Generator Margins by EDF	*£Mn*	12.78	37.40	46.92	101.20	28.02	83.63
Change in Generator Margins by EON	*£Mn*	0.72	11.99	13.26	28.41	-1.85	0.01
Change in Generator Margins by RWE	*£Mn*	3.23	37.15	35.22	82.78	3.77	29.31
Change in Generator Margins by Scottish Power	*£Mn*	4.11	12.42	20.75	39.74	9.45	18.25
Change in Generator Margins by SSE	*£Mn*	11.45	34.40	45.12	88.74	21.84	50.51
Change in Generator Margins for Other Players	*£Mn*	178.52	674.99	679.03	1,461.64	279.77	935.45

Source: NERA/Imperial

5. Conclusions

A key objective of this assignment was to estimate the potential welfare effects of the CMA's proposal to introduce zonal transmission loss factors in the British wholesale electricity market, and to examine the sensitivity of our estimates to changes in fundamental assumptions.

- **We find material cost savings can be achieved through applying zonal transmission loss factors**

We have shown that, across a range of scenarios, the policy results in total cost savings of between £53 million and £282 million in present value terms if we value changes in net imports to Britain at prevailing market prices. The range is narrower and of a similar order of magnitude if we value changes in net imports to Britain based on the change in costs in neighbouring markets at between £204 million and £362 million. This confirms the finding from our previous study prepared for RWE[40] that a significant cost saving can be achieved through the introduction of zonal transmission loss multipliers.

- **However, the distributional effects between or amongst generators and consumers are uncertain**

Our modelling also highlights uncertainty around some effects of the proposed policy, notably the distributional effects between producers and consumers, or between consumers and producers in different regions. Specifically, while theory suggests (and our modelling demonstrates) zonal transmission loss multipliers will tend to reduce total power system costs by improving the efficiency of despatch, the effect on wholesale energy and capacity prices is ambiguous. Market prices may rise or fall depending on the change in the marginal cost faced by the generator (or many generators over the course of a year) that set the market price on the margin.

Our modelling identifies that the effect of the policy on market prices varies materially across scenarios: the change in prices can be positive (beneficial to producers, detrimental to consumers) or negative. The modelled change in costs faced by consumers (and the change in margins earned by generators) as a result of the policy can also be of an order of magnitude larger than the modelled cost savings. For this reason, our modelling provides little information on the scale of the distributional effects of the policy between consumers or producers.

We also find that the regional distributional effects, which cause consumer bills and generator profits in some regions to rise or fall by more than in other regions, are small when compared to the total change in bills or generator margins that affects all consumers and producers in aggregate through changes in wholesale prices.

Given these uncertainties in the distributional effects, we conclude that they should be given little weight in assessing the effects of the policy.

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40 NERA Economic Consulting and Imperial College London (11 May 2015), The Welfare Effects of Locational Transmission Loss Factors in the British Wholesale Electricity Market, Prepared for RWE.

- **The estimated cost savings become more uncertain over time**

Further, our modelling also suggests that the modelled effects of zonal transmission loss factors become more uncertain over time. As described in this report, particularly towards the end of our modelling horizon, we rely on assumptions regarding the location of new generation plant and on future TNUoS charges. The location of new plants can have a material impact on locational variation in loss factors, making our modelled loss factors and the estimated changes in welfare that follow from applying them, increasingly uncertain towards the end of the modelling horizon, given the locational distribution of plant is more uncertain the further into the future we go.

For this reason, the estimated cost savings in the early part of the modelling horizon (to 2026) should probably be afforded more weight in the assessment of this policy than the later period. Over the period to 2026, we estimate total cost savings from the introduction of zonal transmission loss factors of between £97 million and £246 million if we value changes in net imports at prevailing market prices. Alternatively, the modelled effect is between £134 million and £190 million if we value changes in net imports based on the change in generation costs in neighbouring jurisdictions.

Of these two measures, the range of between £134 million and £190 million that values changes in net imports based on the change in generation costs is probably a more reliable estimate, given the volatility we observe in the estimated effect of the policy on prices.

Appendix A. Regression Technique

A.1. Mapping of Loss Factors using a Regression Model

Whilst DTIM uses a "snapshot" approach in calculating marginal loss factors, our power market model (Aurora) defines wind production and demand profile with an hourly 'shape' based on historical market data.

This difference in approach, therefore, requires us to map the DTIM loss factors (which depend on discrete levels of wind production and demand) onto the hourly chronological wind and demand profiles necessary for our market model. We perform the mapping using a regression model. In particular, for each zone, epoch and season, we estimate a regression equation (using the DTIM loss factors) that predicts the marginal loss factors as a function of different specifications of wind production and demand. We then use these regression equations to predict the hourly loss factors in each zone based on the assumed levels of wind production and demand in that hour (as defined by their hourly shape).

For each fundamental scenario (i.e. Reference, High Commodity Price and Low Commodity Price), we estimate 320 regressions in total (=16 zones x 5 epochs x 4 seasons). The regression model specification is as follows:

$$Loss\ Factor = Constant + a_1 \times Wind + a_2 \times Wind^2 + a_3 \times Demand + a_4 \times Demand^2 + a_5 \times (Wind \times Demand) + Error \qquad [1]$$

- The "Loss Factor" variable represents DTIM's marginal loss factors;
- "Wind" represents DTIM's level of wind production given as a load factor between 0 and 1;
- "Demand" represents DTIM's power demand (net of embedded generation) on the British system in MW;
- We include the squares as well as the cross-product of variables "Wind" and "Demand" to capture any non-linearities and/or interactions between the two variables in their effect on loss factors[41]; and
- The "Error" term reflects any variations in loss factor that is not captured by any of the explanatory variables included in this equation.

For each zone, epoch and season, we estimate the coefficients of the explanatory variables $a_1$to a_5 in equation [1] using a weighted least squares technique, placing a higher weight on DTIM snapshots that represent a higher number of hours in a year.

41 For example, losses on a transmission line are an increasing and quadratic function of the current flowing through that line. Hence, loss factors are expected to be disproportionately higher during times of high wind production and/or high load.

Using the output of coefficients from equation [1], we estimate a further equation in order to predict, for each zone, the hourly loss factors based on the assumed demand and wind shapes in that hour. The specification of this regression model is as follows:

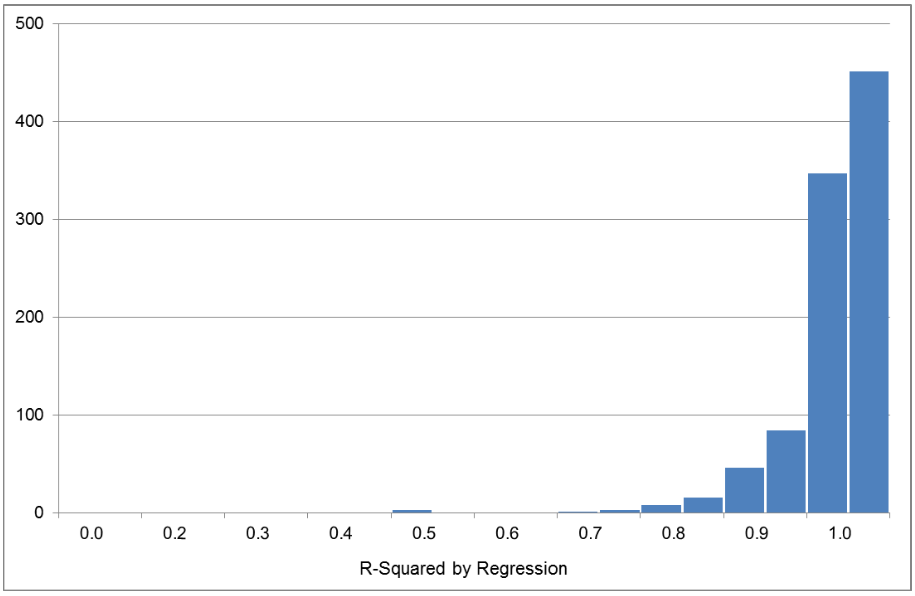
$$\widehat{Loss\ Factor} = \widehat{constant} + Windshape \times \widehat{a_1} + Windshape^2 \times \widehat{a_2} + Demand \times \widehat{a_3} + Demand^2 \times \widehat{a_4} + (Windshape \times Demandshape) \times \widehat{a_5} \quad [2]$$

- "$\widehat{Loss\ Factor}$" is the predicted hourly loss factor in each zone;
- "$\widehat{a_1}$ to $\widehat{a_5}$" are the estimated coefficients from equation [1];
- "Windshape" represents the assumed hourly level of wind production based on historical market data; and
- "Demandshape" represents the assumed hourly demand profile based on historical market data.

A.2. Regression Model Performance

As noted above, regression model [1] provides a means of mapping the loss factors produced using DTIM for each "snapshot" onto chronological hourly time, as a function of wind production and demand. In general, the regression results indicate a very strong statistical "fit" across all fundamental scenarios as shown in Figure A.1, with the R^2 parameter above 0.9 in most cases.

Figure A.1
Histogram of R-Squared by Regression Model for all Scenarios



Appendix B. Seasonal Loss Factors by Quarter

B.1. Loss Factors in the Reference Case: 100% Generator TLMs

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	Zone 11	Zone 12	Zone 13	Zone 14	Zone 15	Zone 16
2017-Q1	1.49%	1.51%	0.94%	0.94%	0.46%	0.27%	0.00%	-1.52%	-0.64%	-1.47%	-3.01%	-3.65%	-2.24%	-3.81%	-3.78%	-3.87%
2017-Q2	-0.57%	-0.52%	-0.92%	-0.86%	-0.85%	-0.91%	0.00%	0.42%	1.48%	0.57%	-0.81%	-1.69%	-0.05%	-1.68%	-1.68%	-1.69%
2017-Q3	0.17%	0.19%	-0.15%	-0.16%	-0.43%	-0.56%	0.00%	0.19%	1.27%	0.41%	-0.54%	-1.29%	-0.11%	-1.41%	-1.33%	-1.44%
2017-Q4	1.43%	1.43%	1.03%	0.98%	0.47%	0.29%	0.00%	-1.84%	-0.97%	-1.68%	-2.75%	-3.31%	-2.32%	-3.54%	-3.49%	-3.65%
2018-Q1	1.34%	1.35%	0.81%	0.81%	0.39%	0.21%	0.00%	-1.51%	-0.64%	-1.44%	-3.00%	-3.62%	-2.21%	-3.77%	-3.75%	-3.84%
2018-Q2	-0.68%	-0.63%	-1.03%	-0.95%	-0.91%	-0.95%	0.00%	0.40%	1.46%	0.56%	-0.87%	-1.75%	-0.08%	-1.74%	-1.74%	-1.74%
2018-Q3	0.09%	0.10%	-0.22%	-0.22%	-0.47%	-0.59%	0.00%	0.22%	1.30%	0.45%	-0.48%	-1.23%	-0.06%	-1.34%	-1.26%	-1.37%
2018-Q4	1.34%	1.33%	0.98%	0.92%	0.42%	0.27%	0.00%	-1.81%	-0.93%	-1.72%	-2.80%	-3.30%	-2.38%	-3.55%	-3.52%	-3.66%
2019-Q1	1.54%	1.54%	1.09%	1.05%	0.44%	0.28%	0.00%	-1.38%	-0.55%	-1.66%	-3.01%	-3.57%	-2.47%	-3.78%	-3.78%	-3.86%
2019-Q2	-0.43%	-0.42%	-0.72%	-0.71%	-0.97%	-0.95%	0.00%	0.73%	1.65%	0.43%	-0.51%	-1.41%	-0.24%	-1.45%	-1.44%	-1.47%
2019-Q3	-0.25%	-0.24%	-0.48%	-0.51%	-0.82%	-0.82%	0.00%	0.42%	1.72%	0.44%	-0.21%	-0.84%	-0.09%	-1.01%	-0.96%	-1.05%
2019-Q4	1.41%	1.40%	1.09%	1.02%	0.43%	0.31%	0.00%	-1.81%	-0.67%	-1.86%	-2.62%	-2.93%	-2.46%	-3.25%	-3.24%	-3.37%
2020-Q1	1.65%	1.65%	1.21%	1.16%	0.50%	0.34%	0.00%	-1.42%	-0.67%	-1.88%	-3.39%	-3.93%	-2.77%	-4.14%	-4.18%	-4.22%
2020-Q2	-0.35%	-0.33%	-0.67%	-0.65%	-0.91%	-0.91%	0.00%	0.68%	1.34%	0.17%	-1.13%	-2.10%	-0.64%	-2.09%	-2.13%	-2.11%
2020-Q3	-0.09%	-0.08%	-0.36%	-0.39%	-0.74%	-0.76%	0.00%	0.38%	1.57%	0.26%	-0.81%	-1.47%	-0.43%	-1.62%	-1.61%	-1.66%
2020-Q4	1.61%	1.59%	1.25%	1.17%	0.51%	0.38%	0.00%	-1.89%	-0.69%	-1.94%	-2.86%	-3.20%	-2.61%	-3.52%	-3.52%	-3.64%
2021-Q1	1.73%	1.72%	1.27%	1.22%	0.53%	0.37%	0.00%	-1.46%	-0.69%	-1.92%	-3.45%	-4.00%	-2.82%	-4.22%	-4.25%	-4.30%
2021-Q2	-0.33%	-0.31%	-0.65%	-0.63%	-0.90%	-0.89%	0.00%	0.67%	1.30%	0.14%	-1.16%	-2.14%	-0.66%	-2.13%	-2.17%	-2.14%
2021-Q3	-0.05%	-0.04%	-0.33%	-0.36%	-0.72%	-0.75%	0.00%	0.37%	1.53%	0.22%	-0.90%	-1.56%	-0.48%	-1.71%	-1.71%	-1.75%
2021-Q4	1.63%	1.61%	1.27%	1.19%	0.52%	0.38%	0.00%	-1.89%	-0.70%	-1.95%	-2.89%	-3.24%	-2.63%	-3.56%	-3.56%	-3.68%
2022-Q1	1.72%	1.71%	1.26%	1.21%	0.53%	0.36%	0.00%	-1.46%	-0.68%	-1.91%	-3.43%	-3.99%	-2.81%	-4.20%	-4.24%	-4.28%
2022-Q2	-0.32%	-0.30%	-0.65%	-0.62%	-0.89%	-0.89%	0.00%	0.67%	1.30%	0.14%	-1.17%	-2.15%	-0.67%	-2.14%	-2.18%	-2.15%
2022-Q3	-0.03%	-0.03%	-0.32%	-0.34%	-0.71%	-0.74%	0.00%	0.36%	1.51%	0.21%	-0.95%	-1.61%	-0.51%	-1.76%	-1.76%	-1.79%
2022-Q4	1.81%	1.79%	1.44%	1.36%	0.69%	0.53%	0.00%	-1.79%	-0.56%	-1.85%	-2.56%	-2.87%	-2.47%	-3.21%	-3.18%	-3.31%
2023-Q1	2.32%	2.31%	1.85%	1.79%	1.06%	0.85%	0.00%	-1.13%	-0.25%	-1.64%	-2.38%	-2.71%	-2.32%	-3.00%	-2.94%	-3.06%
2023-Q2	0.29%	0.30%	-0.01%	-0.03%	-0.36%	-0.41%	0.00%	0.55%	1.46%	0.08%	-0.18%	-0.75%	-0.43%	-0.87%	-0.81%	-0.90%
2023-Q3	0.28%	0.29%	0.02%	-0.01%	-0.35%	-0.39%	0.00%	-0.09%	1.45%	0.00%	0.07%	-0.39%	-0.38%	-0.59%	-0.50%	-0.62%
2023-Q4	2.26%	2.25%	1.86%	1.80%	1.15%	0.97%	0.00%	-1.26%	-0.02%	-1.44%	-1.53%	-1.72%	-1.90%	-2.10%	-2.01%	-2.15%
2024-Q1	2.46%	2.45%	1.99%	1.94%	1.21%	1.00%	0.00%	-0.93%	-0.13%	-1.52%	-2.04%	-2.35%	-2.14%	-2.65%	-2.56%	-2.70%
2024-Q2	0.30%	0.31%	0.00%	-0.02%	-0.35%	-0.40%	0.00%	0.65%	1.35%	0.01%	-0.39%	-0.99%	-0.55%	-1.09%	-1.04%	-1.12%
2024-Q3	0.31%	0.32%	0.05%	0.02%	-0.33%	-0.37%	0.00%	-0.11%	1.42%	-0.04%	-0.03%	-0.49%	-0.44%	-0.69%	-0.60%	-0.72%
2024-Q4	2.33%	2.32%	1.93%	1.86%	1.19%	1.01%	0.00%	-1.30%	-0.07%	-1.49%	-1.62%	-1.80%	-1.97%	-2.18%	-2.09%	-2.24%
2025-Q1	2.57%	2.56%	2.08%	2.02%	1.28%	1.05%	0.00%	-1.00%	-0.19%	-1.60%	-2.19%	-2.49%	-2.25%	-2.79%	-2.70%	-2.84%
2025-Q2	0.33%	0.34%	0.02%	0.00%	-0.33%	-0.39%	0.00%	0.61%	1.33%	-0.02%	-0.43%	-1.01%	-0.58%	-1.12%	-1.07%	-1.15%
2025-Q3	0.32%	0.33%	0.06%	0.03%	-0.32%	-0.37%	0.00%	-0.11%	1.41%	-0.05%	-0.05%	-0.51%	-0.46%	-0.71%	-0.63%	-0.74%
2025-Q4	2.35%	2.34%	1.94%	1.88%	1.20%	1.01%	0.00%	-1.31%	-0.07%	-1.50%	-1.64%	-1.83%	-1.99%	-2.22%	-2.12%	-2.27%
2026-Q1	2.59%	2.57%	2.09%	2.03%	1.29%	1.06%	0.00%	-0.98%	-0.22%	-1.63%	-2.25%	-2.56%	-2.29%	-2.86%	-2.77%	-2.91%
2026-Q2	0.35%	0.36%	0.04%	0.02%	-0.31%	-0.37%	0.00%	0.65%	1.26%	-0.07%	-0.56%	-1.16%	-0.66%	-1.25%	-1.21%	-1.28%
2026-Q3	0.37%	0.38%	0.09%	0.06%	-0.29%	-0.34%	0.00%	-0.13%	1.36%	-0.10%	-0.21%	-0.68%	-0.55%	-0.87%	-0.80%	-0.91%
2026-Q4	2.35%	2.34%	1.93%	1.87%	1.21%	1.01%	0.00%	-0.82%	0.22%	-1.18%	-0.92%	-1.04%	-1.51%	-1.43%	-1.32%	-1.48%
2027-Q1	2.60%	2.59%	2.13%	2.07%	1.34%	1.09%	0.00%	0.33%	0.85%	-0.46%	0.63%	0.61%	-0.47%	0.26%	0.41%	0.20%
2027-Q2	0.69%	0.70%	0.40%	0.36%	-0.05%	-0.16%	0.00%	1.75%	2.36%	1.14%	3.00%	2.85%	1.43%	2.61%	2.71%	2.55%
2027-Q3	0.48%	0.49%	0.23%	0.19%	-0.17%	-0.27%	0.00%	1.71%	2.33%	1.15%	3.15%	3.03%	1.48%	2.76%	2.88%	2.70%
2027-Q4	2.10%	2.10%	1.71%	1.66%	1.06%	0.86%	0.00%	1.06%	1.33%	0.13%	1.72%	1.80%	0.31%	1.41%	1.55%	1.35%
2028-Q1	2.58%	2.57%	2.11%	2.05%	1.34%	1.08%	0.00%	0.85%	1.16%	-0.11%	1.42%	1.47%	0.05%	1.11%	1.28%	1.05%
2028-Q2	0.72%	0.73%	0.42%	0.39%	-0.02%	-0.14%	0.00%	1.75%	2.34%	1.12%	2.96%	2.80%	1.41%	2.57%	2.67%	2.50%
2028-Q3	0.56%	0.56%	0.29%	0.26%	-0.12%	-0.22%	0.00%	1.68%	2.29%	1.11%	3.09%	2.95%	1.43%	2.68%	2.80%	2.62%
2028-Q4	2.21%	2.20%	1.81%	1.75%	1.13%	0.92%	0.00%	1.00%	1.29%	0.06%	1.64%	1.71%	0.24%	1.32%	1.46%	1.26%
2029-Q1	2.65%	2.64%	2.17%	2.11%	1.39%	1.12%	0.00%	0.82%	1.09%	-0.17%	1.31%	1.35%	-0.03%	1.00%	1.17%	0.94%
2029-Q2	0.80%	0.81%	0.49%	0.46%	0.04%	-0.09%	0.00%	1.75%	2.24%	1.05%	2.82%	2.64%	1.31%	2.42%	2.52%	2.36%
2029-Q3	0.60%	0.61%	0.33%	0.29%	-0.10%	-0.20%	0.00%	1.68%	2.26%	1.09%	3.05%	2.88%	1.40%	2.63%	2.74%	2.56%
2029-Q4	2.28%	2.27%	1.86%	1.81%	1.17%	0.95%	0.00%	0.97%	1.28%	0.04%	1.60%	1.67%	0.20%	1.28%	1.42%	1.22%
2030-Q1	2.75%	2.74%	2.26%	2.20%	1.45%	1.18%	0.00%	0.79%	1.06%	-0.22%	1.23%	1.27%	-0.10%	0.91%	1.08%	0.86%
2030-Q2	0.83%	0.84%	0.52%	0.48%	0.06%	-0.07%	0.00%	1.75%	2.20%	1.02%	2.77%	2.59%	1.28%	2.37%	2.47%	2.31%
2030-Q3	0.64%	0.64%	0.36%	0.32%	-0.07%	-0.18%	0.00%	1.67%	2.24%	1.07%	3.02%	2.84%	1.37%	2.59%	2.71%	2.53%
2030-Q4	2.20%	2.19%	1.82%	1.76%	1.17%	0.96%	0.00%	1.07%	1.25%	0.03%	1.44%	1.55%	0.15%	1.16%	1.27%	1.11%
2031-Q1	2.46%	2.46%	2.09%	2.03%	1.41%	1.17%	0.00%	1.16%	1.08%	-0.15%	0.93%	1.09%	-0.14%	0.75%	0.83%	0.69%
2031-Q2	0.74%	0.75%	0.55%	0.51%	0.16%	0.05%	0.00%	2.13%	2.23%	1.03%	2.45%	2.46%	1.18%	2.22%	2.23%	2.15%
2031-Q3	0.48%	0.49%	0.33%	0.29%	0.00%	-0.09%	0.00%	2.20%	2.18%	1.04%	2.41%	2.47%	1.16%	2.21%	2.22%	2.15%
2031-Q4	1.71%	1.72%	1.44%	1.40%	0.92%	0.75%	0.00%	1.75%	1.40%	0.27%	1.23%	1.41%	0.26%	1.06%	1.05%	1.00%
2032-Q1	2.35%	2.36%	2.01%	1.96%	1.39%	1.17%	0.00%	1.30%	1.09%	-0.13%	0.81%	1.00%	-0.16%	0.67%	0.71%	0.61%
2032-Q2	0.76%	0.77%	0.56%	0.52%	0.17%	0.05%	0.00%	2.14%	2.25%	1.04%	2.47%	2.46%	1.18%	2.23%	2.24%	2.16%
2032-Q3	0.55%	0.56%	0.39%	0.35%	0.05%	-0.05%	0.00%	2.17%	2.18%	1.02%	2.41%	2.45%	1.14%	2.19%	2.20%	2.13%
2032-Q4	1.84%	1.84%	1.55%	1.50%	1.00%	0.82%	0.00%	1.67%	1.37%	0.22%	1.19%	1.37%	0.20%	1.02%	1.01%	0.96%
2033-Q1	2.42%	2.43%	2.08%	2.02%	1.43%	1.21%	0.00%	1.24%	1.05%	-0.17%	0.75%	0.94%	-0.21%	0.60%	0.64%	0.54%
2033-Q2	0.78%	0.79%	0.58%	0.54%	0.19%	0.07%	0.00%	2.13%	2.23%	1.02%	2.45%	2.43%	1.16%	2.19%	2.21%	2.13%
2033-Q3	0.57%	0.58%	0.41%	0.37%	0.06%	-0.04%	0.00%	2.16%	2.17%	1.01%	2.40%	2.44%	1.13%	2.18%	2.19%	2.12%
2033-Q4	1.87%	1.87%	1.58%	1.53%	1.02%	0.83%	0.00%	1.66%	1.38%	0.22%	1.21%	1.38%	0.20%	1.02%	1.02%	0.96%
2034-Q1	2.45%	2.45%	2.10%	2.04%	1.45%	1.22%	0.00%	1.25%	1.07%	-0.17%	0.78%	0.95%	-0.20%	0.62%	0.66%	0.56%
2034-Q2	0.79%	0.80%	0.59%	0.55%	0.20%	0.08%	0.00%	2.13%	2.24%	1.03%	2.46%	2.43%	1.17%	2.20%	2.21%	2.13%
2034-Q3	0.60%	0.61%	0.43%	0.39%	0.08%	-0.03%	0.00%	2.14%	2.18%	1.00%	2.41%	2.44%	1.13%	2.18%	2.19%	2.12%
2034-Q4	1.87%	1.88%	1.58%	1.53%	1.02%	0.84%	0.00%	1.66%	1.39%	0.22%	1.23%	1.39%	0.21%	1.04%	1.04%	0.98%
2035-Q1	2.40%	2.41%	2.06%	2.00%	1.42%	1.20%	0.00%	1.27%	1.08%	-0.15%	0.80%	0.98%	-0.18%	0.65%	0.68%	0.58%
2035-Q2	0.81%	0.82%	0.61%	0.57%	0.22%	0.09%	0.00%	2.13%	2.25%	1.03%	2.47%	2.44%	1.17%	2.21%	2.22%	2.14%
2035-Q3	0.58%	0.59%	0.42%	0.38%	0.07%	-0.03%	0.00%	2.15%	2.17%	1.00%	2.40%	2.43%	1.12%	2.17%	2.18%	2.11%
2035-Q4	1.82%	1.83%	1.54%	1.49%	0.99%	0.81%	0.00%	1.69%	1.39%	0.23%	1.22%	1.39%	0.22%	1.04%	1.03%	0.98%

B.2. Loss Factors in the Low Case: 100% Generator TLMs

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	Zone 11	Zone 12	Zone 13	Zone 14	Zone 15	Zone 16
2017-Q1	1.79%	1.81%	1.14%	1.13%	0.57%	0.32%	0.00%	-1.90%	-0.82%	-1.83%	-3.80%	-4.59%	-2.81%	-4.79%	-4.77%	-4.87%
2017-Q2	-0.81%	-0.76%	-1.21%	-1.13%	-1.09%	-1.15%	0.00%	0.44%	1.74%	0.65%	-1.12%	-2.20%	-0.15%	-2.20%	-2.21%	-2.20%
2017-Q3	0.34%	0.36%	-0.06%	-0.07%	-0.41%	-0.58%	0.00%	0.00%	1.35%	0.29%	-1.08%	-1.95%	-0.41%	-2.09%	-1.99%	-2.12%
2017-Q4	1.93%	1.93%	1.42%	1.37%	0.74%	0.49%	0.00%	-2.41%	-1.32%	-2.20%	-3.74%	-4.39%	-3.06%	-4.67%	-4.63%	-4.80%
2018-Q1	1.60%	1.62%	0.98%	0.98%	0.48%	0.25%	0.00%	-1.88%	-0.81%	-1.80%	-3.77%	-4.56%	-2.77%	-4.74%	-4.74%	-4.82%
2018-Q2	-0.96%	-0.90%	-1.34%	-1.25%	-1.18%	-1.22%	0.00%	0.43%	1.72%	0.63%	-1.18%	-2.27%	-0.17%	-2.25%	-2.27%	-2.25%
2018-Q3	0.25%	0.27%	-0.13%	-0.14%	-0.45%	-0.61%	0.00%	0.04%	1.38%	0.32%	-1.03%	-1.88%	-0.37%	-2.03%	-1.93%	-2.06%
2018-Q4	1.89%	1.89%	1.45%	1.38%	0.78%	0.56%	0.00%	-1.73%	-1.02%	-2.01%	-3.71%	-4.23%	-2.89%	-4.53%	-4.52%	-4.66%
2019-Q1	2.05%	2.05%	1.52%	1.47%	0.74%	0.57%	0.00%	0.67%	0.27%	-1.09%	-3.45%	-3.92%	-2.15%	-4.18%	-4.19%	-4.27%
2019-Q2	-0.55%	-0.53%	-0.88%	-0.87%	-1.16%	-1.13%	0.00%	3.91%	3.19%	1.68%	-0.43%	-1.24%	0.76%	-1.30%	-1.30%	-1.33%
2019-Q3	-0.22%	-0.20%	-0.51%	-0.54%	-0.92%	-0.92%	0.00%	3.32%	3.15%	1.58%	0.04%	-0.52%	0.86%	-0.73%	-0.66%	-0.78%
2019-Q4	2.15%	2.14%	1.75%	1.66%	0.94%	0.80%	0.00%	0.94%	0.45%	-1.00%	-2.54%	-2.78%	-1.79%	-3.15%	-3.15%	-3.30%
2020-Q1	2.22%	2.21%	1.70%	1.64%	0.86%	0.69%	0.00%	1.22%	0.38%	-1.10%	-3.82%	-4.21%	-2.28%	-4.48%	-4.53%	-4.57%
2020-Q2	-0.46%	-0.44%	-0.83%	-0.80%	-1.10%	-1.08%	0.00%	3.82%	2.81%	1.35%	-1.28%	-2.15%	0.25%	-2.15%	-2.21%	-2.17%
2020-Q3	0.01%	0.02%	-0.34%	-0.37%	-0.80%	-0.83%	0.00%	3.27%	2.94%	1.32%	-0.79%	-1.35%	0.42%	-1.53%	-1.53%	-1.58%
2020-Q4	2.42%	2.39%	1.97%	1.87%	1.07%	0.90%	0.00%	0.80%	0.38%	-1.14%	-2.91%	-3.16%	-2.01%	-3.54%	-3.55%	-3.68%
2021-Q1	2.31%	2.30%	1.78%	1.71%	0.91%	0.73%	0.00%	1.17%	0.35%	-1.16%	-3.90%	-4.31%	-2.34%	-4.58%	-4.63%	-4.67%
2021-Q2	-0.42%	-0.40%	-0.79%	-0.76%	-1.06%	-1.05%	0.00%	3.82%	2.78%	1.33%	-1.33%	-2.20%	0.22%	-2.20%	-2.26%	-2.22%
2021-Q3	0.05%	0.06%	-0.31%	-0.33%	-0.77%	-0.80%	0.00%	3.25%	2.90%	1.28%	-0.90%	-1.47%	0.35%	-1.65%	-1.65%	-1.69%
2021-Q4	2.44%	2.42%	1.99%	1.89%	1.08%	0.91%	0.00%	0.79%	0.37%	-1.15%	-2.96%	-3.21%	-2.04%	-3.59%	-3.60%	-3.73%
2022-Q1	2.30%	2.29%	1.77%	1.71%	0.90%	0.73%	0.00%	1.18%	0.37%	-1.14%	-3.88%	-4.29%	-2.33%	-4.56%	-4.61%	-4.65%
2022-Q2	-0.41%	-0.38%	-0.78%	-0.75%	-1.05%	-1.03%	0.00%	3.83%	2.78%	1.33%	-1.34%	-2.21%	0.22%	-2.21%	-2.27%	-2.23%
2022-Q3	0.08%	0.09%	-0.28%	-0.31%	-0.76%	-0.79%	0.00%	3.25%	2.88%	1.26%	-0.96%	-1.53%	0.32%	-1.70%	-1.71%	-1.74%
2022-Q4	2.58%	2.55%	2.11%	2.01%	1.19%	1.00%	0.00%	0.99%	0.55%	-1.01%	-2.51%	-2.74%	-1.82%	-3.15%	-3.12%	-3.27%
2023-Q1	3.15%	3.14%	2.57%	2.50%	1.62%	1.37%	0.00%	1.14%	0.61%	-1.08%	-2.68%	-2.90%	-2.00%	-3.28%	-3.20%	-3.34%
2023-Q2	0.99%	1.01%	0.60%	0.58%	0.14%	0.07%	0.00%	2.70%	2.42%	0.72%	-0.32%	-0.83%	0.01%	-1.01%	-0.92%	-1.02%
2023-Q3	0.67%	0.68%	0.32%	0.28%	-0.16%	-0.22%	0.00%	2.97%	2.89%	1.14%	0.56%	0.16%	0.58%	-0.12%	0.02%	-0.13%
2023-Q4	3.05%	3.04%	2.53%	2.46%	1.64%	1.41%	0.00%	1.60%	1.12%	-0.58%	-1.21%	-1.37%	-1.23%	-1.86%	-1.73%	-1.90%
2024-Q1	3.26%	3.24%	2.66%	2.59%	1.73%	1.47%	0.00%	1.31%	0.71%	-0.99%	-2.30%	-2.53%	-1.84%	-2.91%	-2.79%	-2.94%
2024-Q2	1.07%	1.08%	0.67%	0.64%	0.21%	0.14%	0.00%	2.51%	2.15%	0.49%	-0.75%	-1.29%	-0.29%	-1.44%	-1.36%	-1.45%
2024-Q3	0.71%	0.72%	0.36%	0.32%	-0.13%	-0.19%	0.00%	2.96%	2.85%	1.10%	0.44%	0.03%	0.52%	-0.24%	-0.11%	-0.25%
2024-Q4	3.13%	3.12%	2.60%	2.52%	1.69%	1.45%	0.00%	1.52%	1.06%	-0.65%	-1.32%	-1.48%	-1.32%	-1.97%	-1.84%	-2.01%
2025-Q1	3.38%	3.36%	2.76%	2.69%	1.80%	1.52%	0.00%	1.20%	0.62%	-1.10%	-2.48%	-2.69%	-1.98%	-3.09%	-2.96%	-3.12%
2025-Q2	1.09%	1.10%	0.68%	0.66%	0.23%	0.15%	0.00%	2.51%	2.15%	0.48%	-0.76%	-1.28%	-0.30%	-1.44%	-1.37%	-1.46%
2025-Q3	0.72%	0.74%	0.37%	0.33%	-0.12%	-0.18%	0.00%	2.95%	2.84%	1.08%	0.41%	0.00%	0.50%	-0.27%	-0.14%	-0.28%
2025-Q4	3.15%	3.14%	2.61%	2.54%	1.70%	1.45%	0.00%	1.50%	1.05%	-0.67%	-1.36%	-1.53%	-1.35%	-2.01%	-1.88%	-2.06%
2026-Q1	3.42%	3.40%	2.80%	2.72%	1.83%	1.54%	0.00%	1.13%	0.54%	-1.18%	-2.61%	-2.84%	-2.08%	-3.22%	-3.10%	-3.25%
2026-Q2	1.15%	1.16%	0.73%	0.71%	0.28%	0.19%	0.00%	2.42%	2.01%	0.35%	-1.01%	-1.55%	-0.47%	-1.69%	-1.62%	-1.70%
2026-Q3	0.78%	0.80%	0.42%	0.38%	-0.08%	-0.15%	0.00%	2.91%	2.77%	1.00%	0.18%	-0.22%	0.38%	-0.49%	-0.37%	-0.50%
2026-Q4	3.08%	3.06%	2.55%	2.48%	1.66%	1.41%	0.00%	2.12%	1.48%	-0.19%	-0.24%	-0.35%	-0.66%	-0.84%	-0.69%	-0.88%
2027-Q1	3.03%	3.02%	2.49%	2.42%	1.59%	1.32%	0.00%	3.70%	2.55%	0.99%	2.30%	2.27%	0.99%	1.81%	2.02%	1.77%
2027-Q2	0.88%	0.89%	0.58%	0.54%	0.10%	-0.01%	0.00%	5.28%	4.41%	2.96%	5.42%	5.15%	3.36%	4.83%	4.99%	4.78%
2027-Q3	0.58%	0.59%	0.29%	0.25%	-0.17%	-0.27%	0.00%	4.94%	4.17%	2.79%	5.48%	5.25%	3.25%	4.89%	5.08%	4.84%
2027-Q4	2.54%	2.53%	2.08%	2.02%	1.32%	1.10%	0.00%	4.51%	3.09%	1.70%	3.86%	3.90%	1.98%	3.40%	3.59%	3.36%
2028-Q1	2.95%	2.94%	2.42%	2.36%	1.55%	1.28%	0.00%	4.35%	2.99%	1.49%	3.51%	3.52%	1.72%	3.06%	3.30%	3.02%
2028-Q2	0.92%	0.93%	0.61%	0.57%	0.13%	0.02%	0.00%	5.30%	4.40%	2.95%	5.38%	5.09%	3.34%	4.78%	4.93%	4.73%
2028-Q3	0.68%	0.69%	0.38%	0.34%	-0.10%	-0.21%	0.00%	4.93%	4.14%	2.75%	5.40%	5.14%	3.19%	4.79%	4.97%	4.74%
2028-Q4	2.65%	2.64%	2.18%	2.12%	1.39%	1.15%	0.00%	4.43%	3.04%	1.63%	3.75%	3.79%	1.89%	3.29%	3.48%	3.25%
2029-Q1	3.01%	3.00%	2.48%	2.41%	1.61%	1.33%	0.00%	4.32%	2.92%	1.42%	3.37%	3.39%	1.64%	2.93%	3.16%	2.89%
2029-Q2	1.00%	1.02%	0.69%	0.65%	0.21%	0.09%	0.00%	5.36%	4.34%	2.90%	5.24%	4.91%	3.26%	4.62%	4.76%	4.57%
2029-Q3	0.74%	0.75%	0.43%	0.39%	-0.05%	-0.16%	0.00%	4.95%	4.11%	2.73%	5.35%	5.05%	3.15%	4.71%	4.89%	4.66%
2029-Q4	2.72%	2.71%	2.23%	2.17%	1.43%	1.18%	0.00%	4.41%	3.04%	1.61%	3.72%	3.75%	1.86%	3.25%	3.44%	3.21%
2030-Q1	3.11%	3.10%	2.56%	2.49%	1.66%	1.37%	0.00%	4.29%	2.91%	1.38%	3.29%	3.29%	1.57%	2.84%	3.07%	2.80%
2030-Q2	1.03%	1.05%	0.72%	0.68%	0.24%	0.12%	0.00%	5.37%	4.31%	2.88%	5.17%	4.84%	3.23%	4.56%	4.70%	4.51%
2030-Q3	0.79%	0.80%	0.47%	0.43%	-0.02%	-0.14%	0.00%	4.96%	4.09%	2.71%	5.32%	5.00%	3.12%	4.66%	4.84%	4.61%
2030-Q4	2.54%	2.53%	2.10%	2.04%	1.36%	1.13%	0.00%	4.42%	3.07%	1.64%	3.50%	3.63%	1.83%	3.14%	3.28%	3.09%
2031-Q1	2.57%	2.57%	2.17%	2.10%	1.43%	1.19%	0.00%	4.22%	2.96%	1.45%	2.83%	3.14%	1.52%	2.71%	2.82%	2.64%
2031-Q2	0.80%	0.82%	0.62%	0.57%	0.21%	0.10%	0.00%	5.08%	4.24%	2.77%	4.65%	4.74%	3.01%	4.43%	4.47%	4.35%
2031-Q3	0.43%	0.45%	0.28%	0.24%	-0.08%	-0.18%	0.00%	4.99%	4.04%	2.68%	4.43%	4.67%	2.91%	4.34%	4.37%	4.26%
2031-Q4	1.81%	1.82%	1.53%	1.47%	0.96%	0.77%	0.00%	4.57%	3.18%	1.84%	3.08%	3.48%	1.91%	3.05%	3.05%	2.97%
2032-Q1	2.35%	2.36%	2.01%	1.95%	1.34%	1.12%	0.00%	4.25%	3.00%	1.50%	2.64%	3.05%	1.51%	2.63%	2.70%	2.56%
2032-Q2	0.82%	0.83%	0.63%	0.59%	0.22%	0.11%	0.00%	5.08%	4.25%	2.77%	4.67%	4.73%	3.02%	4.43%	4.46%	4.34%
2032-Q3	0.51%	0.52%	0.35%	0.30%	-0.03%	-0.13%	0.00%	4.98%	4.06%	2.67%	4.44%	4.66%	2.90%	4.33%	4.35%	4.25%
2032-Q4	1.95%	1.95%	1.65%	1.59%	1.04%	0.84%	0.00%	4.52%	3.18%	1.80%	3.05%	3.45%	1.87%	3.01%	3.01%	2.93%
2033-Q1	2.44%	2.45%	2.09%	2.02%	1.39%	1.16%	0.00%	4.19%	2.97%	1.45%	2.59%	2.98%	1.46%	2.56%	2.63%	2.49%
2033-Q2	0.85%	0.86%	0.66%	0.61%	0.24%	0.13%	0.00%	5.07%	4.23%	2.76%	4.66%	4.71%	3.00%	4.41%	4.44%	4.33%
2033-Q3	0.54%	0.55%	0.37%	0.33%	-0.01%	-0.11%	0.00%	4.97%	4.06%	2.66%	4.44%	4.65%	2.89%	4.32%	4.34%	4.23%
2033-Q4	1.98%	1.99%	1.67%	1.62%	1.06%	0.85%	0.00%	4.52%	3.20%	1.81%	3.07%	3.46%	1.87%	3.02%	3.03%	2.94%
2034-Q1	2.48%	2.48%	2.12%	2.05%	1.41%	1.18%	0.00%	4.20%	2.99%	1.46%	2.63%	3.00%	1.47%	2.58%	2.65%	2.51%
2034-Q2	0.86%	0.88%	0.67%	0.63%	0.26%	0.14%	0.00%	5.07%	4.24%	2.76%	4.68%	4.71%	3.01%	4.41%	4.44%	4.33%
2034-Q3	0.57%	0.58%	0.40%	0.35%	0.01%	-0.10%	0.00%	4.96%	4.08%	2.66%	4.46%	4.65%	2.89%	4.32%	4.34%	4.24%
2034-Q4	1.98%	1.99%	1.68%	1.62%	1.06%	0.86%	0.00%	4.52%	3.22%	1.81%	3.09%	3.48%	1.88%	3.04%	3.05%	2.96%
2035-Q1	2.42%	2.43%	2.08%	2.01%	1.39%	1.16%	0.00%	4.21%	2.99%	1.47%	2.63%	3.01%	1.48%	2.59%	2.66%	2.52%
2035-Q2	0.90%	0.91%	0.70%	0.66%	0.29%	0.17%	0.00%	5.07%	4.25%	2.76%	4.69%	4.70%	3.00%	4.41%	4.43%	4.32%
2035-Q3	0.55%	0.57%	0.38%	0.34%	0.00%	-0.10%	0.00%	4.97%	4.06%	2.66%	4.45%	4.64%	2.89%	4.31%	4.33%	4.23%
2035-Q4	1.93%	1.94%	1.63%	1.57%	1.03%	0.83%	0.00%	4.53%	3.20%	1.81%	3.07%	3.47%	1.88%	3.02%	3.03%	2.95%

B.3. Loss Factors in the <u>High Case</u>: 100% Generator TLMs

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	Zone 11	Zone 12	Zone 13	Zone 14	Zone 15	Zone 16
2017-Q1	1.81%	1.83%	1.16%	1.15%	0.58%	0.33%	0.00%	-1.86%	-0.79%	-1.80%	-3.72%	-4.51%	-2.75%	-4.71%	-4.68%	-4.79%
2017-Q2	-0.78%	-0.73%	-1.18%	-1.10%	-1.07%	-1.13%	0.00%	0.52%	1.81%	0.71%	-0.95%	-2.06%	-0.06%	-2.05%	-2.06%	-2.06%
2017-Q3	0.34%	0.35%	-0.07%	-0.08%	-0.41%	-0.58%	0.00%	0.06%	1.41%	0.34%	-0.96%	-1.87%	-0.35%	-2.01%	-1.91%	-2.04%
2017-Q4	1.92%	1.91%	1.41%	1.35%	0.74%	0.49%	0.00%	-2.39%	-1.30%	-2.19%	-3.74%	-4.39%	-3.04%	-4.66%	-4.62%	-4.79%
2018-Q1	1.62%	1.64%	1.00%	1.00%	0.49%	0.26%	0.00%	-1.84%	-0.78%	-1.77%	-3.70%	-4.48%	-2.72%	-4.66%	-4.65%	-4.74%
2018-Q2	-0.93%	-0.87%	-1.31%	-1.22%	-1.15%	-1.19%	0.00%	0.51%	1.80%	0.70%	-1.00%	-2.12%	-0.08%	-2.10%	-2.11%	-2.10%
2018-Q3	0.25%	0.26%	-0.13%	-0.14%	-0.45%	-0.61%	0.00%	0.09%	1.43%	0.37%	-0.92%	-1.81%	-0.31%	-1.95%	-1.85%	-1.98%
2018-Q4	1.87%	1.87%	1.43%	1.37%	0.77%	0.55%	0.00%	-1.70%	-0.99%	-1.97%	-3.70%	-4.21%	-2.86%	-4.50%	-4.49%	-4.64%
2019-Q1	2.04%	2.04%	1.51%	1.45%	0.72%	0.54%	0.00%	0.70%	0.36%	-1.00%	-3.35%	-3.78%	-2.05%	-4.05%	-4.05%	-4.14%
2019-Q2	-0.57%	-0.55%	-0.91%	-0.90%	-1.20%	-1.18%	0.00%	4.03%	3.43%	1.91%	-0.16%	-0.91%	1.03%	-0.98%	-0.97%	-1.01%
2019-Q3	-0.22%	-0.21%	-0.51%	-0.54%	-0.93%	-0.93%	0.00%	3.65%	3.47%	1.89%	0.50%	-0.06%	1.23%	-0.26%	-0.20%	-0.31%
2019-Q4	2.16%	2.14%	1.75%	1.66%	0.93%	0.80%	0.00%	1.04%	0.55%	-0.90%	-2.38%	-2.62%	-1.66%	-2.99%	-2.99%	-3.14%
2020-Q1	2.21%	2.20%	1.68%	1.62%	0.83%	0.66%	0.00%	1.24%	0.50%	-1.00%	-3.71%	-4.06%	-2.16%	-4.33%	-4.38%	-4.43%
2020-Q2	-0.49%	-0.47%	-0.86%	-0.84%	-1.15%	-1.14%	0.00%	3.95%	3.07%	1.59%	-1.01%	-1.80%	0.53%	-1.82%	-1.86%	-1.83%
2020-Q3	0.00%	0.01%	-0.35%	-0.37%	-0.81%	-0.84%	0.00%	3.73%	3.35%	1.73%	-0.19%	-0.76%	0.90%	-0.94%	-0.93%	-0.98%
2020-Q4	2.43%	2.40%	1.97%	1.88%	1.06%	0.90%	0.00%	0.93%	0.51%	-1.01%	-2.71%	-2.96%	-1.85%	-3.34%	-3.35%	-3.48%
2021-Q1	2.30%	2.29%	1.75%	1.69%	0.87%	0.69%	0.00%	1.18%	0.46%	-1.06%	-3.79%	-4.16%	-2.22%	-4.43%	-4.48%	-4.52%
2021-Q2	-0.45%	-0.43%	-0.83%	-0.80%	-1.12%	-1.11%	0.00%	3.95%	3.04%	1.57%	-1.06%	-1.86%	0.50%	-1.87%	-1.92%	-1.89%
2021-Q3	0.05%	0.06%	-0.31%	-0.34%	-0.79%	-0.82%	0.00%	3.73%	3.32%	1.69%	-0.30%	-0.86%	0.84%	-1.04%	-1.04%	-1.08%
2021-Q4	2.45%	2.43%	1.99%	1.89%	1.07%	0.90%	0.00%	0.92%	0.51%	-1.02%	-2.75%	-3.00%	-1.87%	-3.39%	-3.40%	-3.53%
2022-Q1	2.29%	2.28%	1.75%	1.68%	0.86%	0.69%	0.00%	1.19%	0.48%	-1.05%	-3.77%	-4.14%	-2.21%	-4.41%	-4.46%	-4.51%
2022-Q2	-0.44%	-0.41%	-0.81%	-0.79%	-1.11%	-1.10%	0.00%	3.95%	3.04%	1.56%	-1.07%	-1.87%	0.50%	-1.88%	-1.93%	-1.90%
2022-Q3	0.07%	0.08%	-0.29%	-0.32%	-0.77%	-0.80%	0.00%	3.73%	3.30%	1.68%	-0.35%	-0.91%	0.82%	-1.09%	-1.09%	-1.13%
2022-Q4	2.61%	2.58%	2.12%	2.03%	1.19%	1.00%	0.00%	1.09%	0.65%	-0.90%	-2.08%	-2.28%	-1.58%	-2.68%	-2.65%	-2.81%
2023-Q1	3.22%	3.21%	2.59%	2.52%	1.59%	1.32%	0.00%	1.07%	0.66%	-1.02%	-1.70%	-1.82%	-1.57%	-2.18%	-2.09%	-2.26%
2023-Q2	1.04%	1.05%	0.58%	0.56%	0.06%	-0.04%	0.00%	2.64%	2.59%	0.88%	1.16%	0.69%	0.67%	0.53%	0.62%	0.47%
2023-Q3	0.64%	0.65%	0.27%	0.23%	-0.24%	-0.31%	0.00%	3.12%	3.07%	1.35%	2.24%	1.77%	1.32%	1.54%	1.65%	1.47%
2023-Q4	3.08%	3.07%	2.53%	2.46%	1.61%	1.37%	0.00%	1.60%	1.12%	-0.54%	0.01%	-0.04%	-0.74%	-0.48%	-0.37%	-0.57%
2024-Q1	3.35%	3.33%	2.69%	2.62%	1.70%	1.41%	0.00%	1.18%	0.72%	-0.96%	-1.12%	-1.20%	-1.34%	-1.56%	-1.44%	-1.63%
2024-Q2	1.12%	1.13%	0.64%	0.62%	0.12%	0.01%	0.00%	2.41%	2.32%	0.65%	0.72%	0.24%	0.38%	0.09%	0.18%	0.04%
2024-Q3	0.68%	0.70%	0.31%	0.27%	-0.21%	-0.28%	0.00%	3.12%	3.05%	1.32%	2.16%	1.67%	1.27%	1.44%	1.55%	1.38%
2024-Q4	3.17%	3.15%	2.60%	2.53%	1.66%	1.41%	0.00%	1.52%	1.05%	-0.62%	-0.11%	-0.15%	-0.84%	-0.59%	-0.49%	-0.69%
2025-Q1	3.48%	3.46%	2.80%	2.73%	1.77%	1.46%	0.00%	1.06%	0.62%	-1.08%	-1.31%	-1.38%	-1.49%	-1.74%	-1.62%	-1.82%
2025-Q2	1.15%	1.16%	0.67%	0.65%	0.14%	0.03%	0.00%	2.40%	2.32%	0.64%	0.69%	0.22%	0.36%	0.07%	0.16%	0.02%
2025-Q3	0.70%	0.71%	0.32%	0.28%	-0.20%	-0.28%	0.00%	3.11%	3.04%	1.31%	2.14%	1.64%	1.26%	1.41%	1.52%	1.35%
2025-Q4	3.19%	3.17%	2.62%	2.54%	1.67%	1.41%	0.00%	1.50%	1.05%	-0.63%	-0.14%	-0.19%	-0.86%	-0.63%	-0.53%	-0.72%
2026-Q1	3.52%	3.50%	2.83%	2.76%	1.80%	1.48%	0.00%	0.98%	0.55%	-1.15%	-1.44%	-1.52%	-1.58%	-1.88%	-1.76%	-1.95%
2026-Q2	1.21%	1.22%	0.72%	0.70%	0.19%	0.06%	0.00%	2.30%	2.18%	0.52%	0.45%	-0.03%	0.20%	-0.17%	-0.09%	-0.22%
2026-Q3	0.76%	0.78%	0.37%	0.33%	-0.16%	-0.24%	0.00%	3.09%	2.99%	1.25%	1.97%	1.46%	1.17%	1.23%	1.34%	1.17%
2026-Q4	3.10%	3.08%	2.54%	2.47%	1.60%	1.35%	0.00%	2.16%	1.46%	-0.20%	0.67%	0.73%	-0.29%	0.28%	0.41%	0.19%
2027-Q1	2.96%	2.96%	2.39%	2.32%	1.44%	1.15%	0.00%	3.88%	2.43%	0.88%	2.50%	2.71%	1.08%	2.29%	2.46%	2.20%
2027-Q2	0.53%	0.55%	0.21%	0.16%	-0.30%	-0.39%	0.00%	5.53%	4.31%	2.90%	5.58%	5.45%	3.44%	5.18%	5.29%	5.08%
2027-Q3	0.00%	0.01%	-0.27%	-0.31%	-0.73%	-0.79%	0.00%	4.90%	4.04%	2.65%	5.36%	5.45%	3.24%	5.13%	5.27%	5.03%
2027-Q4	2.26%	2.26%	1.81%	1.74%	1.01%	0.79%	0.00%	4.58%	2.95%	1.51%	3.56%	4.04%	1.89%	3.56%	3.71%	3.46%
2028-Q1	2.87%	2.86%	2.31%	2.24%	1.38%	1.10%	0.00%	4.57%	2.85%	1.34%	3.37%	3.69%	1.68%	3.25%	3.45%	3.16%
2028-Q2	0.56%	0.58%	0.23%	0.18%	-0.28%	-0.38%	0.00%	5.57%	4.30%	2.89%	5.59%	5.41%	3.44%	5.15%	5.26%	5.04%
2028-Q3	0.03%	0.04%	-0.26%	-0.30%	-0.72%	-0.79%	0.00%	4.89%	4.02%	2.62%	5.35%	5.39%	3.21%	5.07%	5.21%	4.97%
2028-Q4	2.37%	2.37%	1.90%	1.83%	1.08%	0.85%	0.00%	4.51%	2.91%	1.45%	3.49%	3.96%	1.82%	3.47%	3.63%	3.38%
2029-Q1	3.00%	2.99%	2.43%	2.35%	1.48%	1.19%	0.00%	4.59%	2.78%	1.28%	3.27%	3.55%	1.60%	3.12%	3.32%	3.03%
2029-Q2	0.72%	0.74%	0.37%	0.32%	-0.16%	-0.27%	0.00%	5.72%	4.25%	2.88%	5.54%	5.26%	3.39%	5.02%	5.12%	4.92%
2029-Q3	0.01%	0.02%	-0.28%	-0.33%	-0.75%	-0.82%	0.00%	4.91%	4.00%	2.61%	5.35%	5.33%	3.19%	5.02%	5.16%	4.92%
2029-Q4	2.43%	2.42%	1.94%	1.87%	1.11%	0.87%	0.00%	4.51%	2.92%	1.45%	3.50%	3.95%	1.81%	3.46%	3.62%	3.36%
2030-Q1	3.11%	3.10%	2.52%	2.44%	1.54%	1.23%	0.00%	4.59%	2.79%	1.27%	3.27%	3.51%	1.57%	3.08%	3.27%	2.99%
2030-Q2	0.77%	0.79%	0.41%	0.36%	-0.12%	-0.24%	0.00%	5.76%	4.23%	2.87%	5.51%	5.20%	3.37%	4.96%	5.06%	4.86%
2030-Q3	0.02%	0.03%	-0.28%	-0.32%	-0.75%	-0.83%	0.00%	4.91%	3.99%	2.59%	5.35%	5.30%	3.18%	4.99%	5.13%	4.89%
2030-Q4	2.25%	2.25%	1.81%	1.74%	1.01%	0.79%	0.00%	4.42%	2.83%	1.29%	3.03%	3.60%	1.57%	3.11%	3.23%	3.01%
2031-Q1	2.27%	2.28%	1.87%	1.79%	1.03%	0.77%	0.00%	4.04%	2.39%	0.63%	1.51%	2.38%	0.65%	1.91%	1.99%	1.79%
2031-Q2	0.05%	0.07%	-0.12%	-0.18%	-0.56%	-0.65%	0.00%	4.89%	3.66%	1.85%	2.99%	3.71%	1.97%	3.38%	3.38%	3.24%
2031-Q3	-0.23%	-0.22%	-0.36%	-0.41%	-0.72%	-0.78%	0.00%	4.57%	3.46%	1.75%	2.88%	3.73%	1.90%	3.34%	3.35%	3.21%
2031-Q4	1.36%	1.38%	1.12%	1.04%	0.50%	0.32%	0.00%	4.12%	2.41%	0.77%	1.37%	2.46%	0.75%	1.94%	1.92%	1.81%
2032-Q1	2.06%	2.07%	1.71%	1.62%	0.91%	0.66%	0.00%	3.98%	2.31%	0.49%	1.07%	2.05%	0.42%	1.59%	1.62%	1.45%
2032-Q2	0.04%	0.06%	-0.13%	-0.19%	-0.57%	-0.66%	0.00%	4.89%	3.66%	1.84%	3.00%	3.68%	1.96%	3.36%	3.35%	3.21%
2032-Q3	-0.22%	-0.20%	-0.35%	-0.40%	-0.73%	-0.79%	0.00%	4.55%	3.48%	1.74%	2.91%	3.72%	1.89%	3.34%	3.34%	3.20%
2032-Q4	1.48%	1.49%	1.21%	1.14%	0.56%	0.37%	0.00%	4.07%	2.42%	0.72%	1.36%	2.42%	0.71%	1.90%	1.88%	1.76%
2033-Q1	2.14%	2.15%	1.78%	1.69%	0.96%	0.71%	0.00%	3.91%	2.26%	0.42%	0.99%	1.97%	0.35%	1.50%	1.53%	1.36%
2033-Q2	0.06%	0.08%	-0.12%	-0.17%	-0.56%	-0.66%	0.00%	4.87%	3.63%	1.82%	2.96%	3.64%	1.93%	3.32%	3.31%	3.18%
2033-Q3	-0.20%	-0.19%	-0.34%	-0.39%	-0.72%	-0.79%	0.00%	4.54%	3.48%	1.73%	2.90%	3.71%	1.88%	3.32%	3.33%	3.19%
2033-Q4	1.50%	1.51%	1.23%	1.15%	0.57%	0.37%	0.00%	4.07%	2.44%	0.73%	1.38%	2.44%	0.71%	1.91%	1.89%	1.78%
2034-Q1	2.15%	2.16%	1.79%	1.70%	0.96%	0.70%	0.00%	3.92%	2.28%	0.43%	1.02%	1.98%	0.35%	1.51%	1.54%	1.37%
2034-Q2	0.05%	0.07%	-0.12%	-0.18%	-0.57%	-0.66%	0.00%	4.87%	3.64%	1.82%	2.97%	3.64%	1.93%	3.32%	3.31%	3.17%
2034-Q3	-0.20%	-0.18%	-0.34%	-0.40%	-0.73%	-0.80%	0.00%	4.54%	3.49%	1.73%	2.92%	3.71%	1.88%	3.33%	3.33%	3.19%
2034-Q4	1.49%	1.51%	1.22%	1.14%	0.56%	0.36%	0.00%	4.07%	2.46%	0.74%	1.40%	2.46%	0.72%	1.93%	1.92%	1.80%
2035-Q1	2.10%	2.11%	1.74%	1.66%	0.93%	0.68%	0.00%	3.94%	2.28%	0.44%	1.04%	1.99%	0.37%	1.53%	1.56%	1.39%
2035-Q2	0.06%	0.08%	-0.12%	-0.17%	-0.56%	-0.66%	0.00%	4.87%	3.64%	1.81%	2.98%	3.62%	1.91%	3.30%	3.29%	3.15%
2035-Q3	-0.21%	-0.19%	-0.35%	-0.40%	-0.73%	-0.80%	0.00%	4.54%	3.48%	1.73%	2.90%	3.70%	1.87%	3.32%	3.32%	3.18%
2035-Q4	1.47%	1.48%	1.20%	1.12%	0.55%	0.36%	0.00%	4.08%	2.43%	0.74%	1.38%	2.44%	0.72%	1.92%	1.90%	1.79%

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NERA
ECONOMIC CONSULTING

NERA Economic Consulting
Marble Arch House, 66 Seymour Street
London W1H 5BT
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com