ENERGY MARKET INVESTIGATION

Notice regarding assessment methodology for losses remedy – consultation on methodology and scenarios

1. On 7 July 2015, the Competition and Markets Authority (CMA) published its provisional findings and notice of possible remedies (the Remedies Notice) for the energy market investigation (the Investigation). Remedy 1 of the Remedies Notice set out the introduction of a new standard condition to electricity generation, supply, interconnection, transmission, and distribution licences to require that variable transmission losses are priced on the basis of location in order to achieve technical efficiency.

2. On 16 September 2015, the CMA published a notice informing parties of its intention to carry out additional analysis in relation to transmission losses and remedy 1, specifically a new cost-benefit analysis for the introduction of pricing for losses (the Losses Notice). On 20 October 2015, the CMA published a notice informing parties of its intention to appoint NERA Economic Consulting (www.nera.com), 66 Seymour Street, London, W1H 5BT (NERA) for the purpose of this assessment (the Intention to Appoint Notice). On 30 October, the CMA published a notice outlining parties' comments on the CMA's approach and the CMA's view in response (the Confirmation of Appointment Notice).

3. NERA has now provided the CMA with its proposed methodology, scenarios and underlying assumptions. The CMA has been involved in the preparation of the scenarios and their adaptation to NERA/Imperial's methodology and models. It now wishes to consult on these methodology, scenarios and underlying assumptions. Attached to this notice are the following two documents:

   (a) a paper entitled 'Methodology for assessing the impact of zonal transmission loss multipliers'; and

   (b) a presentation entitled 'NERA/Imperial zonal losses modelling: Meeting on detailed modelling assumptions'.

4. With this work, the CMA wishes to test the sensitivity of gains from pricing losses to a range of plausible scenarios. The CMA would like to encourage parties to submit comments on both methodology and scenarios to assist the

inquiry group in deciding how much evidential weight to put on this work. The CMA would also welcome it if parties were to conduct any of their own analyses and submit results to it in full knowledge of the analysis NERA is already performing.

5. We would like to invite comments on the documents attached to this notice in two forms. First, we would welcome written comments **by 12.00pm on Monday 14 December 2015**. To submit comments, please email Will Fletcher, Project Manager, at EnergyMarket@cma.gsi.gov.uk or write to him at:

Energy Market Investigation
Competition and Markets Authority
Victoria House
Southampton Row
London
WC1B 4AD

6. Secondly, we would like to invite interested parties to a roundtable session, facilitated by NERA, where the methodology, scenarios and underlying assumptions will be discussed in greater detail. The session will take place **at 2.00pm on Tuesday 15 December 2015** at the CMA's offices in London. Please can interested parties email Will Fletcher, Project Manager, at EnergyMarket@cma.gsi.gov.uk outlining your organisation's wish to attend and who will be attending. For logistical reasons we will limit the number of attendees to two per party.

8 December 2015

NERA
ECONOMIC CONSULTING

Methodology for Assessing the Impact of Zonal Transmission Loss Multipliers

Prepared for the CMA

4 December 2015

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Contents

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). The scope of this report is as follows:

- Chapter 2 sets out the method we intend to follow in order to assess the costs and benefits of a zonal transmission losses scheme; and
- Chapter 3 sets out some key features of some scenarios we intend to examine to test the sensitivity of the impact of a zonal transmission losses scheme to changes in underlying assumptions on market fundamentals.

2. Methodology

2.1. Our Modelling Tools

We will use two key modelling tools for this assignment, which we describe in more detail below. Both models have been applied through numerous previous studies, both separately and together. Notably, we intend to use broadly the same modelling framework as we applied in our recent study of the impact of zonal transmission losses for RWE.[1]

Both the models described below will 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. 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 was 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

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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.

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 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 intend to run the model for every single hour of the modelling horizon. However, to the extent we use Aurora to select optimal generation investments, we will need to 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.

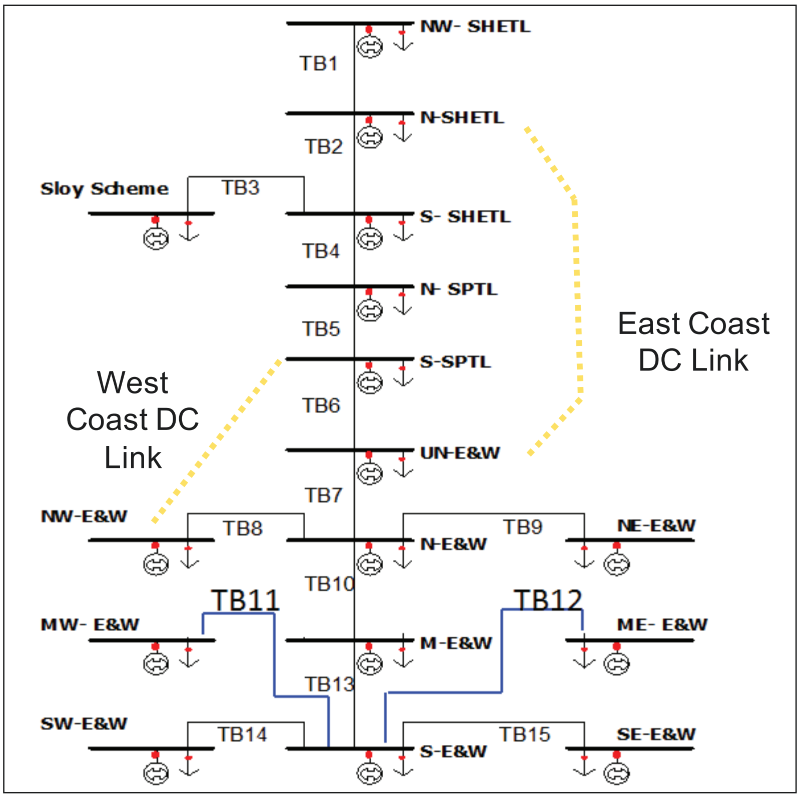
2.1.2. Imperials Dynamic Transmission Investment Model

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.[2] 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).

[2] 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.

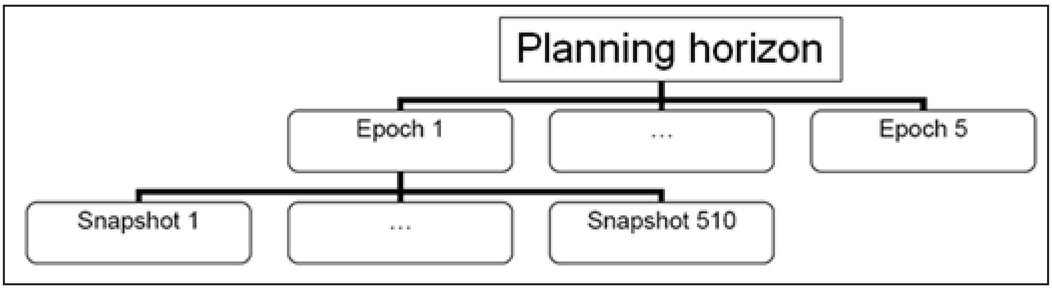
Figure 2.1
DTIM Radial Network



Source: Imperial

We will 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.

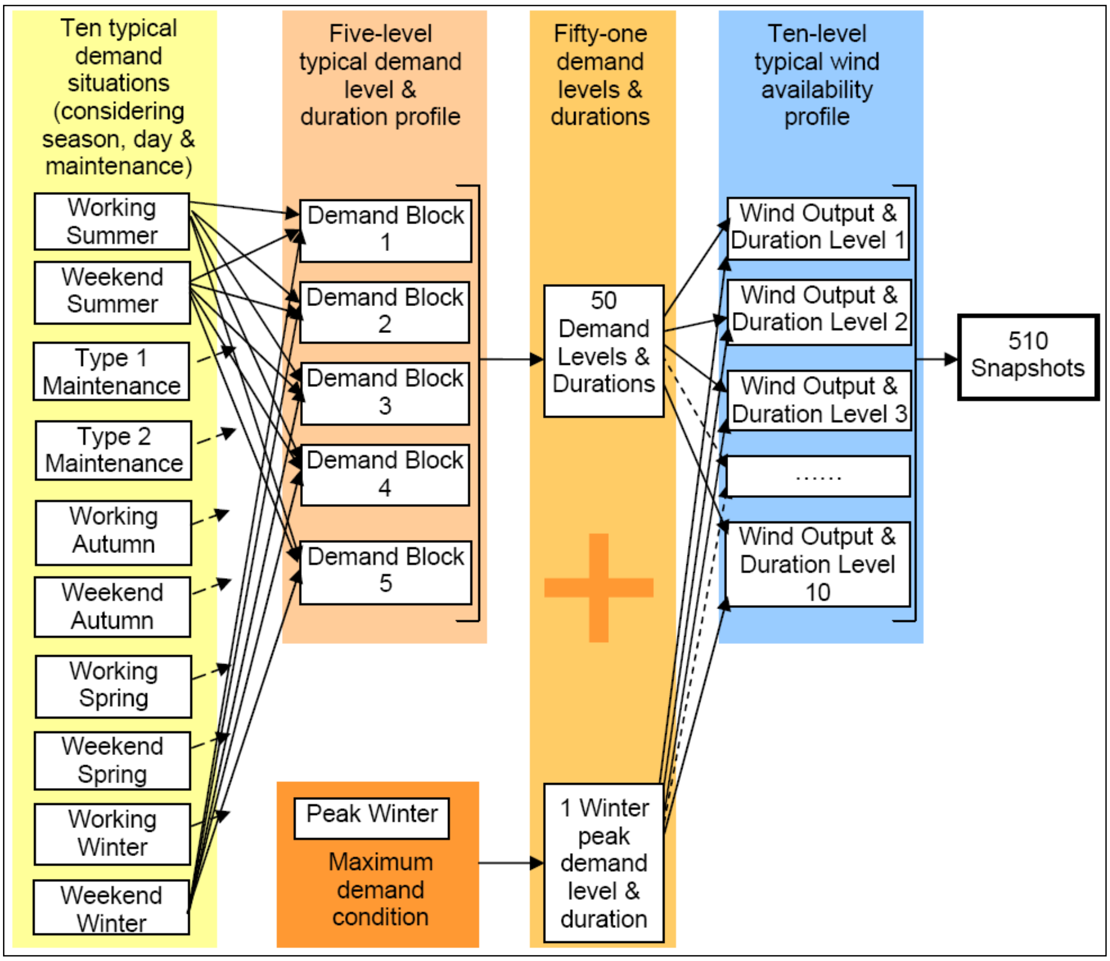
Figure 2.2
DTIM Epochs



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 procedure to examining the impact of zonal transmission losses

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

1. We will begin by running NERA's Aurora model (described further below) to optimise the generation mix. Hence, Aurora will select 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 will be constrained to some degree by our modelling assumptions. For instance, we will form exogenous

assumptions on the penetration and mix of low carbon plant, and we will 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. As well as forecasting the generation mix using Aurora, as described above, we will also use this modelling tool to place endogenously determined new generation plant around the system (discussed further in Section 2.2.2 below), and pass data on plant capacities and locations to DTIM. Aside from these results from the first model run, we will also populate DTIM with the same demand and generation marginal cost assumptions as we use in Aurora.
3. We will then run DTIM to build the transmission network and estimate zonal transmission loss factors over the entire modelling horizon, which we will 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 will 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 will 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. 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, we do not need to form assumptions on plant location. However, we need to form assumptions on new plants developed endogenously by Aurora.

We will use a combination of exogenous assumptions and modelling to define the location of new plant, which in reality will be 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, both of which are selected endogenously through the modelling procedure, which means 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 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. We will therefore need to form assumptions on the location of new plant and propose to assume that the location of new plant is not affected by whether zonal loss factors are in place or not.[3] As set out below, we propose the following approach to forming locational assumptions for each technology:[4]

- **New wind and other renewable capacity:** For renewables and other low carbon technologies our aim is to define a set of assumptions that broadly reflect current government policy. We intend to project the output we assume will come from onshore and offshore wind farms and other renewables based on a range of government policy statements, including from DECC's 2015 Updated Energy and Emissions Projections (UEEP) Reference Scenario, and from data on the renewables project pipeline. We will place wind capacity around the system by selecting the sites that are most economic, given assumptions on the wind resource potential for individual sites, the costs of developing alternative wind sites, and so on. In particular, we will take WACM2 TNUoS charges from the recent study we conducted during the Project TransmiT process.[5] The model we will use to select the most economic wind projects is described extensively in the same previous NERA/Imperial study,[6] albeit we will update the assumptions on the future penetration of onshore and offshore wind. For other renewables capacity, we will place the capacity by reference to public information on planned cites and existing cites.

- **New CCGT and OCGT capacity:** We intend to use our Aurora model to select how much new investment in these technologies is required, when, and where. To make this assessment, we will take assumptions on TNUoS, NTS exit tariffs, land costs, and so on from our Project TransmiT study.[7] We also intend to use assumptions on the maximum deployment of plants by region from the same study. This approach means we may have some small differences between the location of plant across our commodity price scenarios (described in the next chapter). For instance, higher carbon prices may cause existing coal plant to retire sooner, creating more need for new CCGT investment, the location of which will be determined by the model.

- **New nuclear capacity:** We will take assumptions on the penetration of new nuclear from the 2015 UEEP Reference Scenario. We will need to make assumptions on which particular new nuclear units come online, and in what order. We will make these assumptions based on the order of expected commissioning dates for new nuclear projects

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3 We may test the hypothesis that zonal loss factors do not affect locational investment decisions 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.

4 In principle, the generation mix could change in response to different future commodity price trajectories, but such changes may not be possible if there are constraints on new build choices due to (1) limits to the feasible development rates for some low carbon technologies, or (2) if government policy does not react to changes in commodity costs because it wishes to support a mix of low carbon technologies.

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, Appendix C.

6 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, Appendix A.

7 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, Appendix C.

currently in the development pipeline, using expected commissioning dates for each project as indicated by published sources.

- **New CCS capacity:** We propose to assume that new CCS capacity comes online following the UEEP Reference Case. We will assume the CCS capacity projected in the UEEP will be split equally across four locations along the east coast of Great Britain, reflecting a scenario in which CO_2 transport hubs emerge in these locations to share infrastructure to access depleted North Sea oil and gas fields. We propose to assume all new CCS capacity is split equally between coal and gas, with the same 50:50 split between these technologies in all cases. We have not proposed to optimise the location of CCS using Aurora (or any other model), as there is little evidence available on geographic variation in CO_2 transport and storage costs.

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.[8]

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.

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8 On the face of it, this approach might appear to be an imprecise method for computing marginal changes in losses because, if the resulting loss factors were subsequently used to re-despatch the system, transmission flows would change and so too would marginal loss factors. However, DTIM avoids the need for this sort of iteration by selecting generation despatch and network investments to minimise the total costs of the system, including the cost of losses. Using this approach, the initial pattern of despatch from which we compute loss factors already accounts for an optimized flow of power around the system to minimise the joint cost of generation despatch *and losses*.

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 and wind production profile that varies per hour. We will perform this mapping using a regression procedure. Essentially, for every season, zone and epoch, we will estimate a regression equation based on the DTIM results that predicts marginal loss factors as a function of demand and wind production. We will 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 will involve estimating 320 regressions in total (= 16 zones x 5 epochs x 4 seasons), and based on previous experience, we think it will probably be appropriate to estimate the following regression specification:

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

- 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.
- The "Error" term represents the variation in loss factors not explained by the other parts of the equation.

We intend to estimate 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.

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 will 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) then 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.

Once the outputs from DTIM are available, we will perform a set of statistical diagnostic tests to ensure the regression model described above forms a reasonable basis for estimating the underlying marginal change in losses from changes in injection by zone across different wind and demand levels.

2.2.5. Market modelling and conducting a CBA

The final stage of our modelling procedure is then to use these loss factors in the Aurora model. 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 will take the change in constraint costs from DTIM, as the Aurora model does not account for transmission constraints within GB.

We will 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.

2.3. Outputs from the CBA Calculations

Following discussion with the CMA, the CBA calculations will be conducted on the assumption that the new transmission loss mechanism is implemented from 1 January 2017, and we will compute the impact on costs, etc., over the period to the end of 2035. We will discount future costs using the social time preference rate specified in the HMT "Green Book" of 3.5% (real).[9]

We present below in Table 2.1 a proposed table of contents for the CBA output tables to be provided to the CMA. For each scenario, we will present the impact of introducing zonal losses on costs, etc. relative to retaining uniform national loss factors:

- We present information on changes in generation costs and the cost of constraints and losses, including the value/cost of emissions reduction/increases;
- We show the change in the cost of net imports valued at prevailing power prices, as well as the change in generation costs in neighbouring markets, to help isolate the scale of the transfer to/from GB consumers from the impact of the policy on trade. We distinguish effects on trade with the Irish and Continental European markets;
- For a given set of fundamentals assumptions (commodity prices, etc.) we will hold generation and transmission investment decisions constant across the zonal and uniform model runs. Hence, the table does not show the impact on fixed costs;
- We show the impact on consumer bills, both in aggregate and broken down by region; and

[9] Note, however, that when we annuitise the fixed costs incurred by private investors we will use market discount rates based on the cost of capital relevant to the applicable investments. For instance, we will annuitise generation capital costs at a Weighted Average Cost of Capital applicable to private power generation investors.

- We show the impact on generators by region, and the impact by major generation player.

Table 2.1
Proposed Contents of Key Outputs Table

Modelling Result	Units	Calculation Procedure
Total Change in Generation Costs	£m	Sum of the sub-categories below.
Change in Fuel Costs	*£m*	Computed from Aurora, based on change in dispatch patterns and assumed fuel prices
Change in Generation Variable O&M Costs	*£m*	Computed from Aurora, based on change in dispatch patterns and assumed VOM
Generation CO2 Costs	*£m*	Computed from Aurora, based on change in dispatch with emissions valued at the EUA price plus CPS rate (or alternative assumption, eg. DECC social cost of carbon?)
Generation SO2 and NOX Costs	*£m*	Computed offline, based on change in dispatch and valuing emissions using Defra assumptions.
Change in Cost of Transmission Losses	£m	Computed from Aurora outputs, by multiplying change in dispatch by marginal loss factors from DTIM
Change in Cost of Constraint Management	£m	Computed from DTIM.
Total Change in Costs within GB	£m	Sum of the sub-categories below.
Change in Net Import Cost from Ireland	£m	Change in Net Import Costs = Sum over importing hours{ Price in other jurisdiction x import } - Sum over exporting hours{ Price in other jurisdiction x export }
Change in Generation Costs in Ireland	£m	Computed in Aurora: change in fuel, CO2, and VOM from plant in neighbouring markets
Change in Net Import Cost from Continental Europe	£m	As for Ireland
Change in Generation Costs in Continental Europe	£m	As for Ireland
Total Change in Costs	£m	Calculated from above

Modelling Result	Units	Calculation Procedure
Changes in Consumer Bills		
Change in Wholesale Purchase Costs	£m	
Change in Energy Purchase Costs	£m	Computed from change in Aurora price forecast
Change in Capacity Market Costs	£m	Computed from change in Aurora price forecast
Change in Low Carbon Support Costs	£m	Calculated from Aurora outputs (CFD FIT supported plant need higher support payments is wholesale energy prices fall, or vice versa if they rise)
Change in Cost of Transmission Losses	£m	As above (not modelled explicitly within Aurora, but we assume this is passed through)
Change in Cost of Constraint Management	£m	As above (not modelled explicitly within Aurora, but we assume this is passed through)
Total Aggregate Change in Consumer Bills	£m	
Distributional Effects		
Change in Customer Bill: National Average	£/yr	Calculated in the same way as the aggregate impacts on consumer bills (shown above), but dividing the total savings by demand, averaging across years and multiplying by the consumption of a representative consumer (eg. domestic consumer = circa 4,000kWh)
Change in Customer Bill in North Scotland	*£/yr*	As above, but adding/subtracting the additional benefit/cost that comes from lower/higher regional TLM
Change in Customer Bill in South Scotland	*£/yr*	Ditto
Change in Customer Bill in North England/Wales	*£/yr*	Ditto
Change in Customer Bill in Midlands of England/Wales	*£/yr*	Ditto
Change in Customer Bill in South West England/Wales	*£/yr*	Ditto
Change in Customer Bill in South East England/Wales	*£/yr*	Ditto

Modelling Result	Units	Calculation Procedure
Changes in Generator Margins		
Changes in Generator Margin: National Total	£m	Calculated from the Aurora model. Essentially, = ∆Revenue - ∆Cost
Change in Generator Margins in North Scotland	*£m*	Regional breakdown of the above
Change in Generator Margins in South Scotland	*£m*	Ditto
Change in Generator Margins in North England/Wales	*£m*	Ditto
Change in Generator Margins in Midlands of England/Wales	*£m*	Ditto
Change in Generator Margins in South West England/Wales	*£m*	Ditto
Change in Generator Margins in South East England/Wales	*£m*	Ditto
Change in Generator Margins by Major Player 1	*£m*	Same information as above, but aggregated by player not region
Change in Generator Margins by Major Player 2	*£m*	Ditto
Change in Generator Margins by Major Player 3	*£m*	Ditto
etc	*£m*	CMA to confirm list of players for which we should extract results
Change in Generator Margins for other Players	*£m*	Row 48 less sum of impacts on major players named above

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3. Modelling Scenarios

3.1. Proposed Scenarios for Long-term Commodity Costs

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

3.1.1. 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 the potential 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)[10] and from DECC (2015)[11].

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: a Current Policies Scenario, a New Policies Scenario and a 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.[12]

DECC also produces coal, gas and EU ETS CO_2 prices, 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.[13]

In the case of both these sources, we assume the prices they quote are for the main reference prices used in the UK, namely ARA API#2 steam coal and NBP gas, even though the sources themselves do not provide clear definitions.

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*

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10 IEA, World Economic Outlook 2015

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

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

12 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.

13 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.

might be necessary"[14] 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 announced 'cap',[15] and does not re-introduce it afterwards;
- 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).

3.1.2. 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.[16]
- 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),[17] which we add to the underlying 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.[18] We hold these assumptions constant in real terms.

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14 HM Treasury, Budget 2014, p33.

15 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).

16 Carbon Trust, Conversion Factors, 2011 update

17 Based on a diverse range of NERA project experience.

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

We also propose to use the assumptions listed above as the basis for our modelling of the impact of locational losses.

3.1.3. Implications for the competitiveness of GB coal and GB gas plant

Figure 3.1 is a 3x3 matrix illustrating the evolution of the marginal cost of coal and gas in Great Britain based on the IEA 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.

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 3.1 show that, based on current fossil fuel and CO_2 prices, coal and gas are relatively close in the merit order.
- As the top-left-hand-panel of Figure 3.1 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 a 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 3.1), 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.

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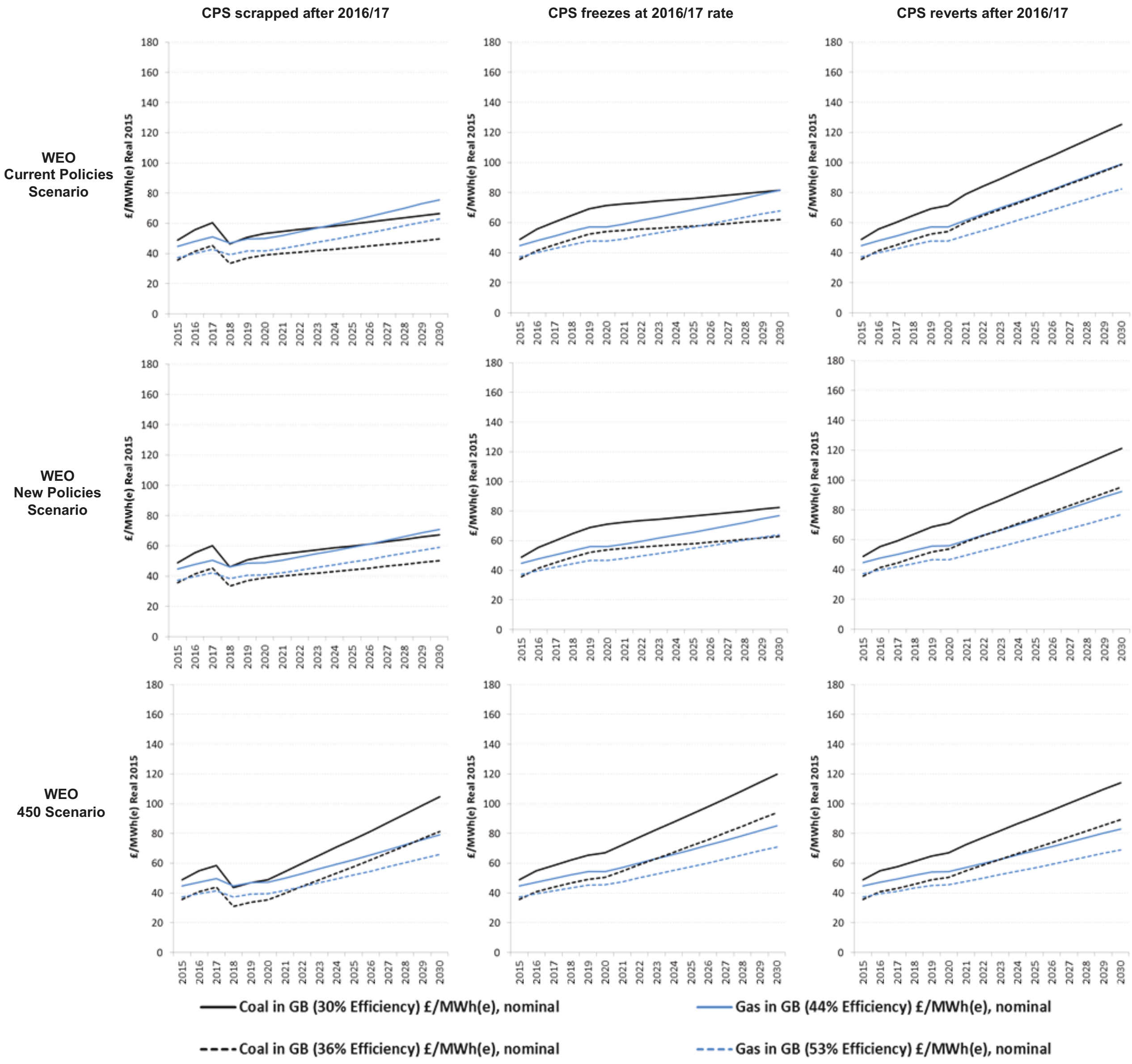
Figure 3.1
Marginal Cost by Generation Source:
Coal vs. Gas in GB for a Range of Efficiencies (IEA)



We have also prepared similar charts for the DECC commodity price scenarios. As **Error! Reference source not found.** Figure 3.2 shows, when we take the DECC low case and the low case on CPS (top-left), 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 3.1. 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.

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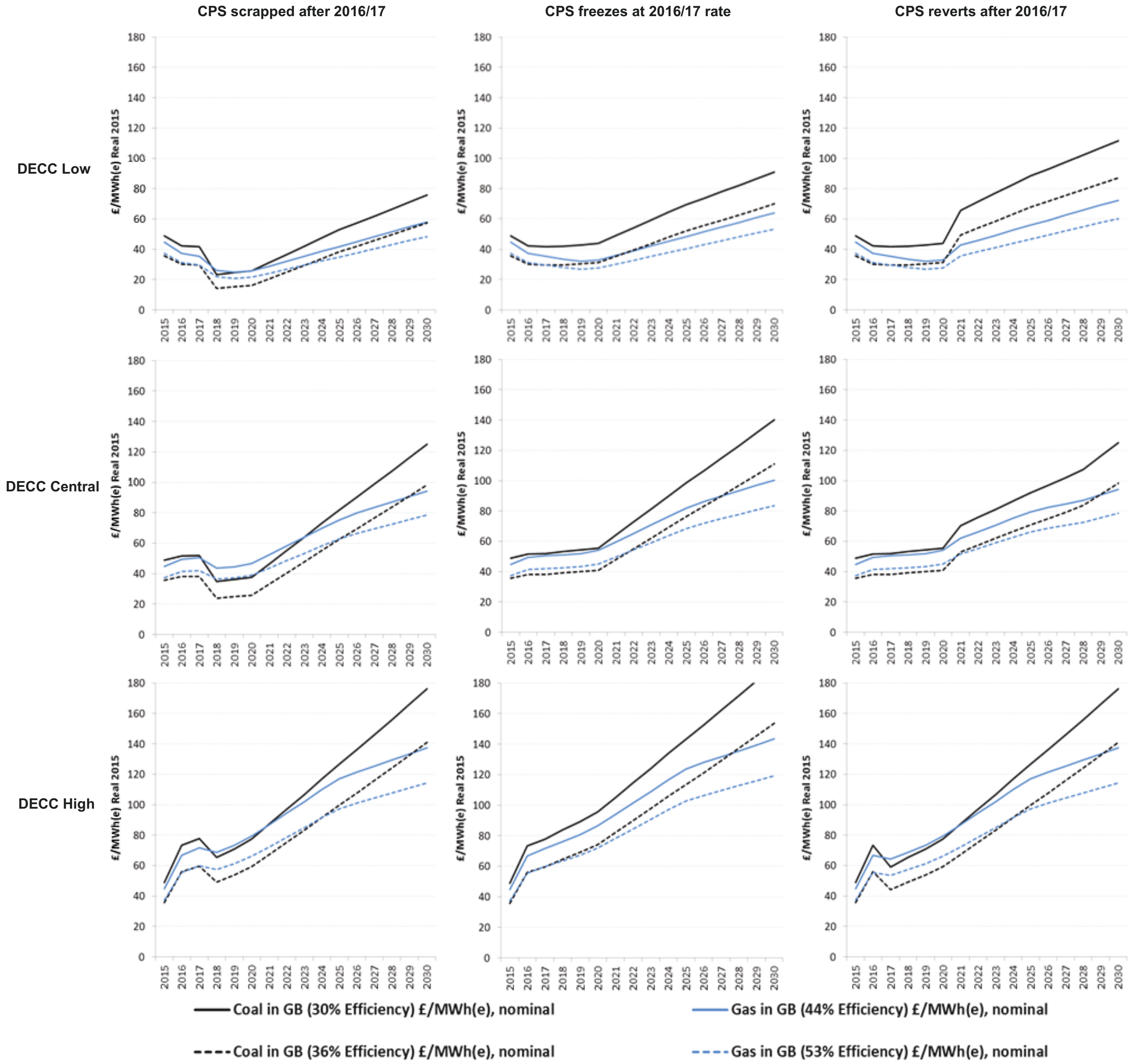
Figure 3.2
Marginal Cost by Generation Source:
Coal vs. Gas in GB for a Range of Efficiencies (DECC)



3.2. Conclusions on Scenario Definition

As noted above, our overriding objective is to define around three baseline scenarios on the relative position of coal and gas in the merit order. The research above suggests that we can achieve this by examining a range of scenarios drawn from the IEA and DECC, and a range of scenarios on the UK CPS. This would involve defining three scenarios as follows:

- The DECC scenarios may be less informative than relying on the IEA scenarios, as the DECC scenarios have less variation in coal/gas CCGT marginal costs. We therefore propose to:

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 - Base our "reference case" scenario around the IEA New Policies scenario, combined with the Central CPS scenario (support rates frozen indefinitely); and
 - Define a "high case", which is least advantageous to coal relative to gas CCGT, using the IEA 450 scenario, combined with the High CPS scenario (Carbon Price Floor = £30/tCO_2 in 2020, £70/tCO_2 in 2030, real 2009 prices).

- We will also consider a "low case", which is most advantageous to coal relative to gas CCGT, using the DECC Low scenario, combined with the Low CPS scenario (abolished after 2016/17). We suggest using the DECC low case rather than the IEA Current Policies case because this is the scenario in which coal appears the most competitive of all those considered above, and we are seeking to examine a wide range of sensitivities on the spread between the marginal costs of these technologies.

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NERA/Imperial Zonal Losses Modelling: Meeting on Detailed Modelling Assumptions

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London

3 December 2015

Insight in Economics™

Contents

- **Demand**
- Existing and Thermal Generation
- Low Carbon Generation
- Interconnection and Transmission

Demand growth assumptions

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- For energy demand:
  - For underlying demand growth, we take the growth rate implied by the “central” scenario from DECC’s UEEP (2015) and apply it to actual demand (including losses) from 2014 from DUKES (2015)
  - We add on top electric vehicles and heat pump demand based on the “Gone Green” scenario from National Grid’s Future Energy Scenarios (2015).
- For peak demand:
  - We take peak “average cold spell” demand (including embedded generation and losses) reported by NG for 2014
  - We apply a growth rate implied by DECC’s 2015 UEEP (same as for energy demand)
  - We shape the consumption from EVs/HPs across the year based on consumption patterns provided by Imperial College to derive their contribution to peak

Demand growth assumptions

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- Demand elasticity:
  - We do not make explicit assumptions about elasticity – our demand shape is based on actual consumption profiles, which will account for some elasticity as demand/prices rise
  - We have some limited elasticity at extreme peak, but this is a technical assumption, required to allow the model to converge.
- Location of demand:
  - Imperial distributes demand around the transmission system in DTIM based on National Grid data

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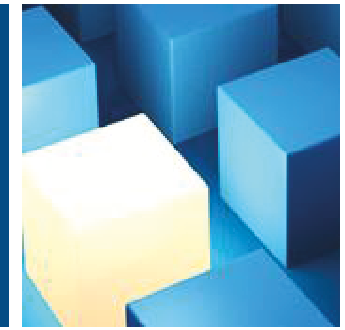

Capacity data for existing plant

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- For existing plant capacities we use up to date information from Platts PowerVision and National Grid:
  - As a starting point, we take June 2015 Platts PowerVision's projections of installed capacities of existing plants and new plants currently under construction
  - We calibrate these capacities to National Grid's July 2015 TEC wherever the registered TEC is lower, to account for cases where PowerVision overstates the true sent-out capacity

Treatment of existing coal plants

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- We assume that around c.12GW of coal capacity will have shut by the end of 2015 under the LCPD, based on published announcements (Powervision/TEC register)
- The decisions of individual plants in respect of IED compliance are not yet published. We therefore use 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 that the units which successfully secured refurbishment contracts at the T-4 auction fit SCR and opt-in to the IED from 2016; and
  - All other coal units opt-out of the IED and run with 17,500 limited operating hours constraints until the end of 2023 when they are forced to close, or until the end of their maximum technical life if sooner.
- We further assume that all unabated coal plants close by 2025 in line with the recent government policy announcement.
- Broadly, by constraining coal plants' operating hours and operating lives our assumptions are conservative, in the sense that this approach limits somewhat the impact of zonal loss factors

Treatment of Longannet

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- Given the importance of north-south power flows in determining loss factors, we need to consider the treatment of Longannet:
  - SP has announced its intention to close the plant in 2016
  - We assume this decision could be changed if the economics of the plant improved
- We therefore propose to:
  - Assume Longannet closes in 2016 in our "reference case" as announced by SP
  - Assume it remains online till 2023 in the "low case", which is designed to be most favorable to coal
  - Assume Longannet closes in 2016 in our "high case" , which is designed to be least favorable to coal

Programmed expansions and closures of other thermal plant

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- We base new entrant assumptions (in the short-term) on the results of the first T-4 Auction
  - We factor in Capacity Agreements awarded to existing plants in the T-4 auction:
  - We assume that all existing plants that were awarded contracts in the T-4 auction stay online for the duration of their contract
- We incorporate the 2.6 GW of new-build capacity awarded Capacity Agreements in the T-4 auction as follows:
  - Include 1.66 GW of generic new entrant CCGT, to represent Trafford power station
  - Include 965 MW of generic new build peaking capacity (i.e. OCGT) to represent the remaining new build capacity, made up from small embedded generators, awarded Capacity Agreements in the T-4 auction, of which 735 WM has a 15-year contract, 32 MW has a 14-year contract and 198 MW has a 1-year contract.
- We model CCGT/OCGT closure decisions within Aurora, based on the economics of each plant. We assume the major oil-fired plants that have opted out of the LCPD will close by the end of 2015 (where they have not already done so).

Technology choice and location for endogenous capacity expansion

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- We allow our model to endogenously expand capacity from OCGT and CCGT technologies
- The location of new plants is a function of TNUoS charges, NTS exit charges, land costs, and exogenous constraints on the zonal build limits
- The exogenous zonal build limits reflect our analysis of system growth requirements and land availability performed for the Project TransmiT study

New entrant costs

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- Cost and performance assumptions are taken from our analysis of:
  - 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 average capital and O&M costs from these publications and also adjust 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.

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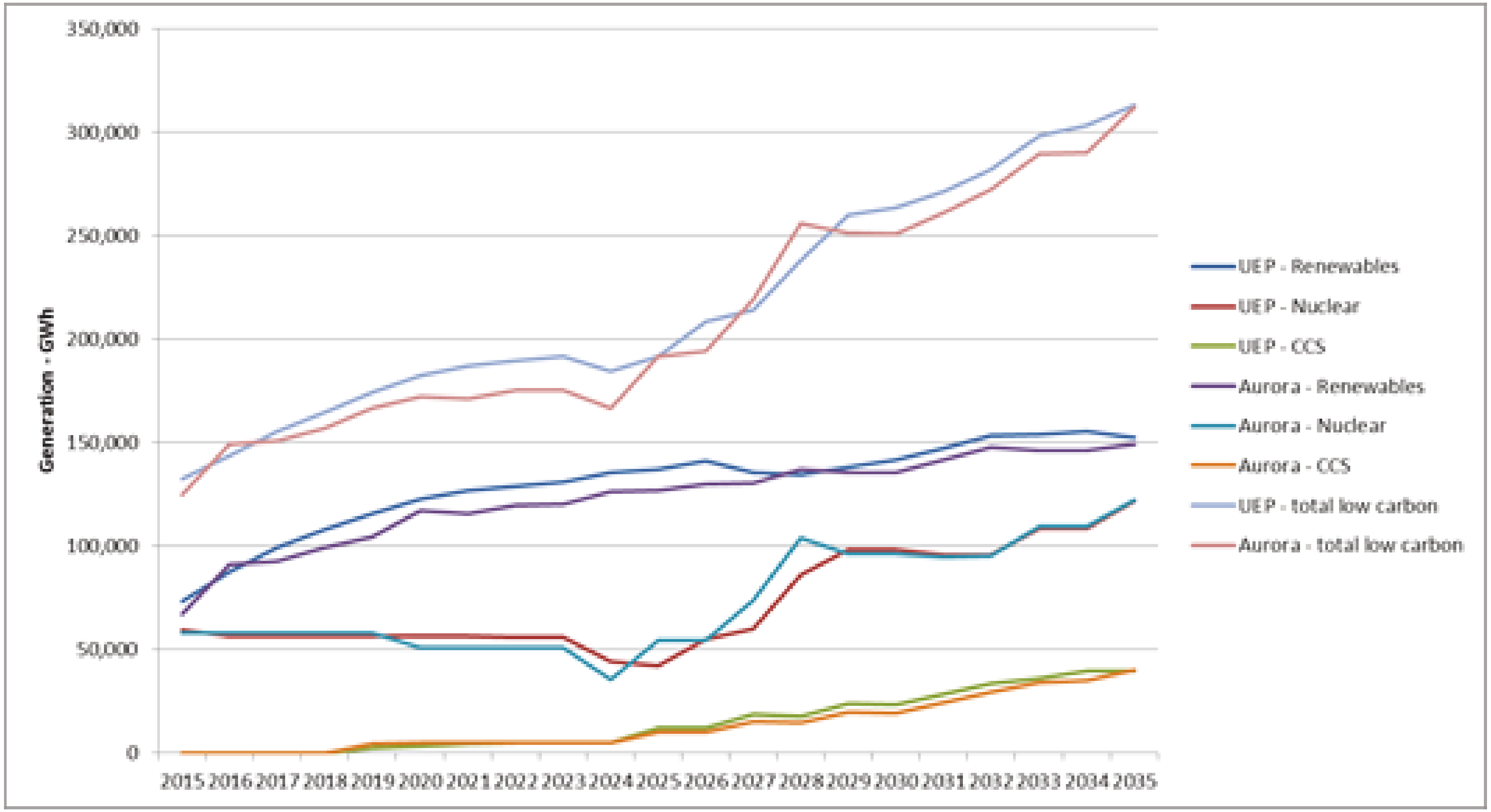
Our low carbon generation assumptions are broadly based on the UEEP (2015) “reference case”



The future mix and penetration of renewable technologies

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- We take the current capacity mix of renewables from DECC's 2015 DUKES database as a starting point.
- We assume growth of each technology based on an analysis of the project pipeline between 2015 and 2020 from the RESTATS database (January 2014).
- We assume biomass capacity reflects the UEEP 2015 and is located based on the location of projects in the pipeline.
- From 2020 onwards:
  - We assume growth in total renewables matches the UEEP (2015) reference case, achieved through expansion in onshore wind, offshore wind, and solar in proportion to their average growth between 2015 and 2020.
  - This results in onshore/offshore wind capacity of around 11.5GW each by 2020 and solar capacity of 13.7 GW. By 2030 the capacities are 14.1GW, 15.2GW, and 17GW for onshore wind, offshore wind, and solar, respectively.

Location of new wind capacity

- As in our Project Transmit work, our renewables investment model selects the location of wind investments to provide the volume of energy we assume needs to be delivered from onshore and offshore wind
- It optimises location to minimise cost, subject to a range of resource performance and availability constraints:
  - Wind speeds, TNUoS, regional resource caps, variation in offshore costs by seabed depth, etc.
- Solar is spread around the country based on the location of existing capacity.

Lives of existing nuclear plant

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- We assume that decommissioning of existing nuclear plants will follow the path outlined in in the UEEP 2015.
  - The UEEP projections do not provide unit level data.
  - To match UEEP as closely as possible, we assumed all plants achieve 1-year life extensions compared to the currently announced closure schedule.

New nuclear expansions

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- We assume 3.2 GW of new nuclear comes online from 2025 (earliest feasible online date for the first new unit at Hinkley Point).
- Thereafter, we assume that the expansion of nuclear capacity follows the rate reported in UEEP (2015):
  - 9GW of new nuclear capacity by 2028,
  - 14.3GW by 2035.
- We assume the reactors are commissioned in the following order: Hinkley Point, Sizewell, Oldbury, Wylfa, Sellafield, Broadwell .This order is an assumption, as published sources of the likely order of commissioning (eg. Platts Powervision) have the projects coming on at the same date.

Growth in CCS

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- We assume no new CCS capacity in the short-term, reflecting the recent decision to withdraw funding for CCS demonstration
- Thereafter, we assume the expansion of CCS capacity follows UEEP (2015):
  - 3.5GW of total CCS capacity by 2030, and 8GW by 2035
  - We assume CCS projects are split equally between coal and gas technologies
  - We assume CCS projects are split evenly between the north and south, located in 4 transmission zones close to North Sea oil and gas infrastructure that could be reused for CO_2 transportation
  - We randomise the *order* of project commissioning across coal/gas projects and between transmission zones.
  - We assume that despatch of CCS plants will be on the basis of its marginal cost, ie. any support does not distort efficient despatch
- Assuming a mix of coal/gas CCS spread throughout the country is arguably conservative, as the impact of zonal loss factors could be greater if there were concentrations of certain plant types in certain locations

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Modelling of Interconnectors

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- We have a fully endogenous treatment of the Irish market, with all plants scheduled and dispatched in the same way as in Great Britain
- 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 markets:
  - We assume GB is a price-taker vis-à-vis these markets
  - The EU price is based on the marginal cost of gas-fired generation, with daily shape reflecting volatility in gas market prices across the year.

Interconnection Expansions

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- The source of interconnector capacities and commissioning dates is a publication from National Grid “Interconnectors”, which envisages the following expansions:
  - 1,000MW with Belgium from 2019 onwards
  - 1,400MW with Norway from 2020 onwards
  - 1,000MW with France from 2020 onwards
  - 1,000MW with Ireland from 2020 onwards

Transmission system cost and capacity assumptions

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- Imperial takes existing transmission boundary capacities based on the capacity currently installed on the GB system.
  - They assume the first HVDC bootstrap will be commissioned, but allow the model to build other transmission investments endogenously.
- Imperial assumes annualised reinforcement costs of £60/MW/km for onshore assets and £160/MW/km, based on their experience and a range of pubslihed cost estimates.
- Bid/offer spreads, which are used to re-despatch generation when modelling the effects of constraints, are taken from the Redpoint study commissioned by Ofgem during the Project TransmiT process.

TNUoS charges

- We take a forecast of WACM2 TNUoS charges from the NERA/Imperial report prepared for RWE during the Project TransmiT process.
- This forecast runs to 2030, so we assume TNUoS charges remain constant in real terms thereafter.

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