Cost Benefit Analysis of Modification P229: Changing to Zonal-Seasonal Transmission Loss Factors

Report Version 1.0

A report for

Elexon

by

London Economics and Ventyx

www.londecon.co.uk

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Contents

Contents

Page

Contents

Page

Tables & Figures

Page

Tables & Figures

Page

Tables & Figures

Page

Tables & Figures

Page

Tables & Figures

Page

Tables & Figures

Page

Tables & Figures

Page

Tables & Figures

Page

Tables & Figures

Page

Executive Summary

This report by London Economics and Ventyx (LE/Ventyx) estimates the costs and benefits for modification proposal P229 for Elexon. The proposed change involves changing the current system of charging for variable transmission losses, where transmission losses are charged to transmission system users on a geographically averaged and annualised basis, to a zonal and seasonal basis.

Our analysis consisted primarily of applying standard Cost Benefit Analysis (CBA) discounting techniques to results from loadflow modelling using the Ventyx PROMOD software and reference case Great Britain electricity market forecast assumptions over the ten year period from 2011 to 2021.

The modelling involved estimating Transmission Loss Factors (TLFs) using the forecast data as if it were estimating the TLFs for the year ahead, and then applying these TLFs to the charges generators and demand (supply companies) faced when using the transmission system.

We conclude that the net benefits of P229 are predicted to be positive and significant on a net present value (NPV) basis. The main benefit comes from production cost savings, reduced fuel consumption by power generators, which are the net fuel savings from the reduction in transmission line losses and changes to the despatch. For the 'reference' scenario (most likely), the overall net discounted benefit, including CO_2 emissions reductions is predicted to be £47.86m.

An element of P229 that extended further previous analysis was explicit modelling and consideration of environmental benefits. Besides CO_2 emissions reductions, major polluting emissions such as SOx and NOx are predicted to be reduced. Including the value of SOx and NOx reductions in the CBA yields much larger net benefits from P229. Including these emissions reductions values in the CBA would give an overall NPV of the net benefit of £276.9m. Since the SOx and NOx per unit reduction benefits are not priced as is the case with CO_2 via EU ETS prices, we have used a marginal abatement cost estimate to price these emissions. While there is some additional uncertainty as to the value of the SOx and NOx via the use of the per unit abatement cost to price the emissions reductions, we believe these estimates are conservative because the "social value" of emissions reductions might be substantially higher.

The distributional impacts of P229 are, in monetary terms, significantly larger than the overall net benefits. The predicted total value in the first full year of generator transfers, for example, goes up to £15.27m in South Scotland in the reference scenario.

The monetary value of distributional impacts, however, should not be directly compared with the CBA values, as the appropriate "weighting" of distributional changes must be defined by the policy maker, which should include a judgment about the relative merits of the current distributional effects of the status quo versus the new distribution of impacts under P229. Further, there is additional uncertainty as to the distributional impacts since i) some companies have demand (supply) and generation in the same region/zones ii) some companies may have operations in multiple zones, and iii) the extent to which cost increases can be passed on to final consumers may impact the overall distributional impacts of P229.

It should be noted that the overall estimated distributional impact on suppliers is expected to be small. Since supply is close to a perfectly competitive business, and since demand changes in response to prices are small in the long term, and even smaller in the short term, then any additional costs to supply a customer in any particular zone would likely be fully passed on to consumers, as a supplier from another lower cost zone cannot come in and offer a lower cost electricity product. This is because the zonal TLF charge will be payable by the location of the demand.

The impact of P229 on demand and on the demand side is expected to be small but positive. P229's impacts from demand redistribution across zones are expected to be small but beneficial to: i) the transmission system; ii) line losses: iii) capacity needs; and iv) emissions reductions This is because the overall effect is expected to incentivise more efficient use of the transmissions system by suppliers, in the same way P229 works for generators. However, there is significant uncertainty around the demand impact estimates, as precise elasticity estimates were not available. Nonetheless, a large body of evidence suggests aggregate elasticities are small but significantly different from zero.

The overall net impact on wholesale prices is expected to be small. As a measure of this, we predict that the system marginal cost (or competitive price) is expected to rise by about 0.59% for peak prices and by 0.71% for offpeak prices. It should be noted that the total impact on wholesale prices should be a function of redespatch costs and net marginal cost reductions for system marginal generators (price setting) due to both TLF, line loss reductions, and redespatch costs. It should also be noted that any degree of less than perfectly competitive behaviour by generators could be expected to mitigate this effect.

The overall impact of P229 is expected to be beneficial to the transmission system in terms of reducing overall levels of line flows and capacity needs, with potential impacts on reduced congestion. Average line flow reductions are predicted to be greatest at the 400kV level.

P229 is not expected to have significant or measurable impacts on plant entry, exit or mothballing. Analysis showed that other locational charges and location-specific concerns form the majority of costs and concerns for plant location decisions, and that P229 is not likely to re-order plant location decisions. In addition, most new entry or exit that might occur during the period is already scheduled, planned or under construction with major locational decisions already made. For plants that have already been sited, it is unlikely that they would have changed their decision, if P229 had been in place when they had made their locational decisions. Finally, TNUoS charges give a non-variable locational incentive to generators, and these, while substantially larger than the financial impact of the proposed TLFs, appear to have little impact on changing overall location decisions for plants.

Our study undertook six scenarios, five in addition to the 'reference' scenario, to assess the sensitivity of the conclusions to changes in the most important input forecasts. We should note that the reference scenario is believed to be the most probable or central scenario. The scenarios chosen were developed using inputs and suggestions from Elexon and the P229 Modification Group. The sensitivities included: high gas prices, low gas prices, volatile fuel price, aggressive offshore wind, and alternative nuclear development.

The total net CBA for each of the six ten-year scenarios was: £47.86, £101.00m, £4.66m, £48.21m, £53.95m, £40.35m, for the reference, high gas prices, low gas prices, fuel volatility, aggressive offshore wind, and alternative nuclear development scenarios, respectively. Including NOx and SOx emissions reductions gives: £276.90m, -£16.74m, £73.5m, £174.55m, £267.76m, £223.95m, respectively.

We conclude that the results and qualitative conclusions are not particularly sensitive to the main uncertainties surrounding the input data forecasts, although the one value for the high gas prices scenarios is slightly negative. The positive NPVs from the CBA are invariant to the scenarios assumption changes when excluding NOx and SOx, and invariant when including NOx and SOx but for the high gas prices scenario. The values are substantial in all cases except the high gas including NOx and SOx and the low gas prices case when excluding NOx and SOx

A summary of the impacts predicted from the introduction of P229 are found in the table below.

Table ES-1: Overview of P229 Impacts - Reference Scenario Savings (Change Case – Base Case)

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Generation (GWh)	Reference	-210	-307	-205	-214	-197	-134	-138	-217	-252	-282
Transmission Losses (GWh)	Reference	-203	-308	-202	-212	-195	-121	-133	-211	-245	-282
Production Cost Savings (£million)	Reference	6.87	7.09	6.40	5.00	3.72	4.82	3.63	8.98	8.49	10.63
NOx Reduction (kt)	Reference	1.65	6.95	3.87	3.34	4.27	2.79	3.04	2.42	2.60	2.84
SOx Reduction (kt)	Reference	7.41	25.86	11.79	12.73	17.13	10.23	8.50	9.69	10.74	8.40
CO2 Reduction (kt)	Reference	885	3,257	1,511	1,458	1,848	1,153	1,205	782	948	818
Off Peak LMP (£)	Reference	0.18	0.38	0.06	0.15	0.15	0.29	0.40	0.39	0.19	0.51
On Peak LMP (£)	Reference	0.07	-0.03	0.38	0.26	0.34	0.44	0.23	0.27	0.25	0.24
%Change in Line Flow 400kV	Reference	-5.27%	-7.31%	-5.17%	-4.94%	-5.33%	-4.16%	-3.58%	-5.34%	-6.13%	-6.95%

*Source: **LE/Ventyx***

The table shows that P229 is expected to have a wide range of benefits across a range of different parameters from the reference scenario.

Most of the other conclusions about P229 impacts are also non-variant to the scenario assumption changes. For example, the impacts on generation are largely expected to be similar across scenarios with generation shifting from north to south. The distributional impacts are similar. Some zones will see significant reductions in generation which could lead to significant financial impacts on some companies. Financial impacts of TLF charging favours generation in the South, demand in the North. Transmission system impacts are similar in that all cases are predicted to reduce line flows; congestion impacts are mostly positive across scenarios. Similarly, our conclusions on plant entry and exit decisions are not predicted to be sensitive to the assumptions, as the overall level of TLF related charges is small relative to TNUoS charging and other factors (local siting, planning) which would impact locational decisions.

In general, emissions reductions are predicted for most cases, with the high gas case being the exception.

The robustness of our analysis in terms of its relationship to previous work on the subject should be noted. Qualitatively, and within a broad but reasonable tolerance, quantitatively, our results are similar to results obtained previously.

The analysis undertaken for P229 has advanced the discussion and available information (from CBAs undertaken for previous BSC zonal TLF Modification Proposals). Furthermore, this CBA has used full hourly modelling of the transmission system and despatch, such that the use of snapshot periods and needs for iterative modelling between despatch and loadflow have been eliminated. The modelling undertaken involved the full simulation of the market when estimating the TLFs *ex ante*, and the modelling of the transmission system under competitive despatch given the *ex ante* estimated TLFs from the previous year's data. While this was important in that it simulated as closely as possible the way TLFs will actually be implemented under P229, it should be noted that based on the modelling, even greater benefits from TLFs could be achieved by reducing the differentials between (due to time/uncertainty) the *ex ante* estimated TLFs and the TLFs that actually occur on the settlement period.

The potential mismatch between the TLFs estimated *ex ante* and the 'correct' TLF signals was a source of concern in previous work. Additional scenario analysis undertaken for P229, such as the fuel volatility case has also showed that while this might naturally reduce the overall benefits of P229, the qualitative conclusion that there is a positive net benefit is preserved.

A number of other concerns raised in previous Modification Proposals concerning TLFs have either been addressed or were not considered relevant or important. For example, we used a marginally higher WACC estimate (4.42%) as our discount rate to address some concern that the previous CBA, using HM Treasury guideline values of 3.5%, might be too low. This low WACC was considered in a scenario analysis along with a higher WACC designed to reflect some of the uncertainty present in global markets. It should be noted that since the savings are predicted to be positive in almost all years, and since the implementation costs are low, the qualitative conclusions are not likely to be sensitive to reasonable ranges of changes in the main underlying parameters.

1 Introduction, Background and Overview

This report by London Economics and Ventyx for Elexon estimates the net cost benefit of changing the way charges for energy losses on the high voltage electricity transmission system are structured in Great Britain. The proposal is to change the current system of geographically and annually averaged transmission loss charges to a zonal and seasonal charging regime. More specifically, P229 proposes to change the Transmission Losses arrangement in the balancing and settlement code (BSC) so that a Transmission Loss Factor (TLF) would be calculated for each BSC season and each GSP zone. TLFs would be estimated each year for each season in the following year using historical and forecast data. The aim of P229 is to allocate variable and marginal transmission loss incentives more appropriately across generators and demand customers on the Great Britain (GB) transmission system to encourage more efficient use of the system such that total generation costs (including loss costs) are reduced.

1.1 Bulk supply of electricity and transmission system losses

The transmission of electricity over distance via the high voltage transmission grid involves energy lost due to resistance of the lines. Losses are both fixed and variable (i.e., per MWh). Variable losses are a function of a number of factors, such as load, voltage and distance. The current system for use of the Great Britain (GB) transmission system under the Balancing and Settlement Code (BSC) charges users for variable losses (those which are proportional to energy injected or off-take) based on a system of estimating transmission loss factors (TLFs). The current regime sets TLFs at zero, and so in essence gives a geographical and annual average Transmission Loss Multiplier (TLM) for all transmission grid users (of the same type: generator, demand). Essentially, all customers are charged a single per unit tariff regardless of location, distance between load and generation, connection voltage, etc. Naturally, some grid users might in fact cause larger variable transmission losses than others (for example, if the distance between the load and the generation was greater), and so the current system might not incentivise the most efficient use of the system.

The use of geographically and annually averaged TLMs (e.g., TLFs=0) means that the price incentives for the optimal use of the transmission system might not be as sharp as they should[1]/could be since: losses are proportional to distance, and losses are impacted by peak demand (which is seasonally correlated). In the limit, it could be envisaged that nodal and hourly TLFs could be used, but this might not be practical due to the needs of measurement, billing and certainty for advance planning (although this hasn't been fully investigated here). However, it might be optimal to adopt a TLF charging regime that gives a more tailored incentive for efficiency transmission system use through time and space than the current regime. Therefore, a system of zonal and seasonal TLF charging has been proposed by Modification Proposal 229.

1.2 Rationale for CBA and change

While the new proposal, were it to be implemented, would most likely reduce losses, it is not obvious *a priori* that it would create an overall net benefit to the system and users, as it involves: a) up-front implementation investment costs of BSC participants in systems and related costs b) redespatch of plant will reduce losses, but should raise pure despatch costs (i.e., costs of serving load, ignoring losses). Presumably some higher energy cost plant will run in some hours when the sum of the loss charges plus their pure energy production cost is less than the sum of total cost for lower production cost plants with higher TLFs. (Note: The calculation we perform is actually the optimisation over all production costs (load *plus* losses), so the 'redespatch' cost is wholly internalised by the model. We give more details on this in Section 2.)

[1] We use the word "should" in terms of economic efficiency. Ultimately, the decision of what is 'best' involves weighing a number of factors, some of which are quantified, some of which are not.

1.3 Proposal P229

1.3.1 Overview of study and terms of reference

At an overview level, it is useful to review the agreed proposal and terms of reference for the study.

The study is to conduct a cost benefit analysis of proposed rule change to BSC P229. P229 proposes seasonal and zonal transmission loss factors.

The terms of reference include these primary goals:

- Estimate the net benefit of P229 to the parties
- Calculation of the evolved TLFs
- Estimation of the market response to P229
- Estimation of the environmental impacts

The estimates should include quantification of:

- Implementation costs to the BSC parties (to be based on estimates provided by the parties to Elexon).
- Distributional impacts
- Impact on transmission losses
- Impact on generation
- Impact on demand
- Impact on the transmission system
- Environmental impacts

1.3.2 History of previous modification proposals

Previously, Elexon commissioned a study to assess the impact of changing from a geographically uniform transmission loss charging arrangement to a zonal one[2]. Oxera used a snap-shot approach (selected hours of the year) and loadflow modelling. The model first studied the loadflow in the system, and then separately looked at despatch of the system given the new system of TLFs.

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[2] OXERA (2006), "What are the costs and benefits of zonal loss charging?" July 2006.

The study found that the net benefits from 'redespatch' would be around £3-£9m per annum and demand-side benefits of £0.3 to £1.2m per annum. Overall the net benefit on a discounted basis from the central scenario to 2020/21 was about £65m (discounting at 3.5% from the HM Treasury Green Book recommended real discount rate values.) When seasonal and gas price factors were considered, the sensitivity analysis suggested the savings would be potentially larger.

Ofgem, as the public body in charge of decisions with respect to changes in the BSC, commissioned a study to consider the previous results[3].

Summarizing broadly, Brattle concluded that Oxera had largely fulfilled their terms of reference and made reasonable and robust conclusions (i.e., the net benefits of changing the TLFs regime were positive and significant), forecasts of inputs, etc. However, Brattle suggested that a number of areas might not be sufficiently robust and possibly could be improved upon including:

- Not considered what would happen if current TLF methodology (using predicted TLFs from year before) was a poor proxy for actual losses
- Use of snapshot periods (average over wide range of market conditions)
    - The redespatch of plant was not done simultaneously optimising over the given TLFs and the complete load-flow of the system (the new TLFs were included as adders to the variable production cost, but there was a chance that there was need for an iterative approach).
- Use of TLFs from the previous year (the TLFs are set using the previous years data).
- May have under-estimated implementation costs (by approximately 20%).
- Discount rate too low.

[3] Brattle (2008), "A review of Oxera's CBA of the introduction of 'zonal losses'."

1.4 Overview of the proposed approach

LE/Ventyx were commissioned by Elexon to undertake the study. The proposed approach was to use Ventyx's proprietary PROMOD loadflow modelling software and Ventyx's reference scenario assumptions for GB. With the ProMod software, Ventyx specialists would be able to model the simultaneous optimisation of despatch and losses. They would also be able to 'mimic' the current TLF setting practice of estimating TLFs from the previous year, applying them to the BSC participants, and then model the competitive despatch along with the resulting transmission system losses that would occur if participants faced those set of TLFs. The modelling would entail running the model for every hour for every year along with a complete representation of the transmission system in GB.

The estimation of the benefits from P229 come from the differences in total production costs (including CO_2), from modelling the system from the 'base case' (the current system of TLFs) to the 'change case' (seasonal and zonal TLFs under P229).

In response to Elexon's request for proposals and also after liaising with Elexon and the P229 Modification group the following additional assumptions were agreed upon.

Due to the computational difficulty of hourly nodal system modelling and the tight timescales of the project, only a limited number of scenarios could be undertaken. It was agreed that in addition to the reference scenario, the following sensitivity cases should be undertaken:

- High gas prices
- Low gas prices
- Volatile fuel prices
- Aggressive offshore wind
- Alternative nuclear development

2 Modelling Approach Overview

This section gives a high-level description of the modelling approach to the CBA analysis. At the heart of the approach, we used the Ventyx proprietary PROMOD loadflow modelling software and the GBEM Reference scenario database and assumptions.

2.1 Modelling electricity despatch and transmission losses

Fundamentally, the problem of setting TLFs is one of the simultaneous optimisation of generation and transmission system use. Mathematically, the problem can be seen as:

1. Minimize total production costs on the system, accounting for
    a. All physical characteristics and constraints of the Transmission system including line losses
    b. All physical characteristics and constraints of the generation system
    c. The need to balance supply and demand
    d. Financial elements (e.g., fuel prices, cost)
    e. The laws of physics and power flow.

A TLF is the estimate of the marginal impact on transmission losses of an injection (offtake) of power to the system.

It should be noted that physically, it is possible (as the BSC is currently written) to define TLFs over every node on the system, but that currently TLFs are set to zero. The current proposal involves zone specific seasonal TLFs, which would be load-weighted averages of all half-hourly nodal TLFs in within each zone.

2.2 Modelling transmission losses and transmission loss factor (TLFs) charging

2.2.1 PROMOD

PROMOD IV is Ventyx's proprietary nodal electricity transmission and despatch model. PROMOD IV is recognized in the industry for its flexibility and breadth of technical capability, incorporating extensive details in generating unit operating characteristics and constraints, 8760 hourly transmission constraints assessment, generation analysis, unit commitment/operating conditions, and market system operations. For over 25 years, energy firms have been using PROMOD IV for a variety of applications that include locational marginal price (LMP) forecasting, financial transmission right (FTR) valuation, environmental analysis, asset evaluations (generation and transmission), generating unit operating strategy evaluation, zonal and hub market price forecasting, transmission congestion analysis, generating unit option valuation, bid analysis, purchased power agreement evaluations, and resource mix assessment for companies with load obligations.

2.2.1.1 Unit Modelling in PROMOD IV

Generating unit data in PROMOD IV contains detailed information for unit cost, operating constraints, forced outage modelling, and transmission impacts. Units can be modelled with up to seven cost segments that reflect heat rate curve efficiencies at various operating levels. Each unit is also linked to a specific bus in the transmission grid so that power injections can be assessed for impacts on transmission line flows and congestion. For the P229 study, only non-embedded generation was modelled so that PROMOD IV could be aligned with the metered volume data provided for hourly loads. Forced outages are modelled on each units through a random Monte Carlo process that ensures the annual outage hours reflect the input Forced Outage Rate and Mean-Time-To-Repair input parameters. Wind units are modelled with explicit hourly profiles that reflect the best available data for diurnal profiles and annual capacity factors based on wind location. Wind generation is not reduced to manage congestion or to lower transmission losses in this study. Existing wind units are located on the appropriate injection buses in the powerflow data, and future wind is added by increasing wind capacity proportionally at existing sites. Pumped storage units are modelled to dynamically optimize pumping and generation based on on-peak and off-peak price differentials.

Special modelling was set up in PROMOD IV data for the coal units that have run-hour limitations through 2015. These units had bid mark ups modelled to increase their cost and thus reduce the annual production. These bid mark ups were developed by iterative simulations and adjusted as required for each sensitivity to reflect high/low Gas prices. This process allows the coal to run an appropriate number of hours but still be used economically, despatching in system hours with higher marginal costs.

2.2.1.2 Emissions Modelling in PROMOD IV

Each generating station in PROMOD can be modelled with production rates for emissions effluents such as SO_2, NOx, and CO_2. These production rates are typically entered in Kg/KJ and are obtained from publically available government reports on emissions production for all large power generation facilities. The emissions production rates along with unit heat rates and fuel consumption are used to determine total production of each effluent from each generating station. PROMOD also allows for setting a price for each effluent that can be included in the unit variable cost to reflect the value of an emissions allowance in the unit despatch decisions. In the P229 study only CO_2 was modelled with a price to impact unit despatch. CO_2, SO_2, and NOx production volumes were all tracked and reported, and costs associated with SO_2 and NOx were applied in post processing.

2.2.1.3 Transmission Powerflow Data

Powerflow data for the P229 study was provided by Elexon and National Grid from a variety of sources. The primary source was the National Grid GB Seven Year Statement website, which provides data downloads for:

- Bus Names and voltage levels
- Generator bus locations
- Transmission Lines with Ratings, Resistance and Reactance values
- Information on Quad-Boosters
- Transformer data
- Future transmission line upgrades

Bus to zone mapping data for metered volume points was taken from spreadsheets provided by Elexon. Bus load distribution was developed from hourly metered volume data and set up seasonally in the model to reflect month-to-month variations in the source data. Contingency data for congestion modelling was developed through independent analysis.

2.2.1.4 Calculation of Line Flows and Losses

PROMOD IV takes a complete set of powerflow data as input, including transmission buses and lines and all associated physical characteristics. From the powerflow information PROMOD IV calculates shift factors that define how power at each injection point flows over the transmission grid. Since PROMOD utilizes a DC load flow solution with no transmission outage modelling, the shift factors do not typically change from hour to hour during the simulation, allowing for a linear programming optimization to determine least cost unit despatch. The flow on all transmission lines can be calculated from shift factors and the final unit despatch levels at each injection bus.

Transmission losses are determined through an iterative solution process within each simulation hour. Once an initial despatch solution is reached, losses are computed mathematically based on the resistance and flow on each transmission line. The computed loss volume for each line is added back into the solution as additional load located at the line terminal buses, and the system is re-solved. If the line flows change, the losses are adjusted and another iteration is performed. This continues until the line flows and loss volumes are consistent between iterations for all branches, usually taking 3-5 solution attempts. Losses are automatically aggregated over all lines for all hours to report total system losses.

2.2.1.5 Transmission Loss Factors

As a by-product of the iterative loss solution, PROMOD IV calculates the marginal impact on system losses for incremental changes at each load and generation bus across the system. These are the Transmission Loss Factors (TLFs) that are the focus of the P229 study. These factors by default are included in the unit despatch optimization to minimize total system costs including savings from loss reductions. PROMOD was enhanced for this study to allow the user to input a TLF value rather than using the hourly node-by-node TLFs calculated by the model. This feature allows for the accurate modelling of the year-to-year delay in the application of TLFs as specified in the P229 terms of reference. The Base simulations for the study have input TLF values of zero to reflect current system procedures. The Change cases for the study were run one year at a time to determine the average seasonal TLF values to be input into the following year simulation. The seasonal, zonal TLFs were constructed by taking weighted average TLFs over all nodes within a zone and averaging over all hours for the defined market seasons.

2.2.1.6 Congestion Management in PROMOD

Since PROMOD calculates flows on all transmission lines using shift factors, it can also manage congestion by re-despatching generation to reduce flow on selected lines. The line rating limits are input into PROMOD and are used as right-hand-side limits in the linear programming solution. If a line exceeds its rating during the LP iterations, a unit with a non-zero shift factor on the constrained line is selected for re-despatch based on the most economic despatch solution. PROMOD IV also handles security-constrained or contingency despatch by maintaining a matrix of different shift factors to apply to each contingency outage event to monitor transmission limits based on post-contingency line flows. The PROMOD IV linear programming solution will move generation levels at each bus to achieve a least cost despatch that keeps all transmission lines at or below their thermal ratings for both pre- and post-contingency flows.

PROMOD IV provides valuable information on the dynamics of the marketplace through its ability to determine the effects of transmission congestion and losses, fuel costs, generator availability, bidding behaviour, and load growth on market prices. PROMOD IV performs an 8760-hour commitment and despatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV forecasts hourly energy prices, unit generation, revenues and fuel consumption, bus-bar and zonal energy market prices, external market transactions, transmission flows and congestion prices. The heart of PROMOD IV is an hourly chronological despatch algorithm that minimizes costs (or bids) while simultaneously adhering to a wide variety of operating constraints; including generating unit characteristics, transmission limits, fuel and environmental considerations, transactions, and customer demand. PROMOD IV uses a multi-pass process to establish robust unit commitment for each generator based on forecast energy prices at the generator injection bus. Unit characteristics captured in the commitment and despatch include multi-segment operation, minimum capacity, ramp up and ramp down limits, start-up costs, minimum runtime and minimum downtime constraints, and operating reserve contribution. The unit commitment process also captures transmission impacts including congestion, marginal losses, phase angle regulators, DC line operation, regional interchange, and tariffs. PROMOD also co-optimizes spinning reserve decisions within hourly despatch.

LE/Ventyx used the Ventyx Autumn Great Britain Energy Market Reference Case Study (Database and Report) as the base case to evaluate the cost benefit analysis of the P229 Solution. The Reference Case Study contains a comprehensive, analysis of Great Britain and includes detailed projections of wholesale power and fuel prices for a 25 year Reference Case from 2009 to 2033.

For generation plant characteristics, we used the Ventyx proprietary databases to represent the GB power market that includes standing data available from public resources such as National Grid Seven Year Statements, DEFRA and other publications published by the government

Key elements of our approach included:

- Hourly load shape for each transmission area that is based on "normalised" historical hourly load data using proprietary "synthetic load shape creator tool".
- General resource data (e.g. unit name, ownership details, location & existing capacity).
- Unit physical and dynamic characteristics (e.g. maximum and minimum capacities, heat rates, min up, min down times, ramp rates, etc.).
- Outages (maintenance rates and forced outages).
- Transportation costs – based on region for coal plants and entry/exit charges for gas plants.
- Modelling emission limits and limits on operational hours (such as modelling Large Combustion Plant Directive 20,000 hours limitation).
- Emission Data (e.g. CO_2 rates, emission removal factors).
- Operating Costs (e.g. Variable O & M).
- Transmission Data (e.g. Interconnector flows) – please note that the BETTA is modelled as a single transmission zone, so only external transmission constraints are included.

The Reference Case includes LE/Ventyx's assumptions on:

- Electricity demand growth forecast.
- Online dates of the plants that are currently in construction.
- Closure dates.
- Plant running regimes.

- Interconnector assumptions.
- Emission prices.
- Monthly fuel price forecasts for fuel oil, gasoil and natural gas (seasonality is incorporated) and yearly forecast for coal prices.
- Capacity expansion plan assumptions.
- Renewables forecast including assumptions on off-shore wind development.

The basis of the analysis was to use PROMOD to develop both a "base case" and a "Change case". In the base case, the current TLFs are set to zero.

PROMOD IV utilized data from the Autumn Reference Case to fully represent all generators and demands in the GB system. PROMOD IV further used data for the transmission system obtained from Elexon, including a network model in PSS/E format along with information on a mapping of transmission buses to each of the 14 zones defined for the study.

The next step was to use PROMOD IV to perform a DC load flow solution to compute shift factors for each generator to each transmission branch. These shift factors will be used to monitor flows on key transmission pathways during the simulation of economic commitment and despatch.

The result is an accurate representation of security-constrained economic despatch that provides bus-level marginal prices including price components for both congestion and losses. PROMOD IV was then set to internally calculate losses through an iterative approach that determines line flows, computes the associated losses, and adds the loss amount back as load to re-solve. As part of this process, PROMOD IV calculated a marginal loss factor for each injection site that explicitly defined the impact of additional injection on total system losses. These Transmission Loss Factors were then accumulated within the model to produce seasonal Transmission Loss Factors for defined zones as required by the P229 study scope.

For further accuracy, the marginal Transmission Loss Factors derived by the model were scaled back to reflect average loss factors, maintaining the relative values of the zones. The loss factor scaling factor of ½ was used.

The simulation was carried out for every hour of the 10-year study period with no TLFs inputs and no optimization of losses in the unit despatch to simulate "Base Case" conditions. This provided a view of how the system would operate without the implementation of P229. Total system losses were calculated hourly in the model based on line flows that result from the DC load flow solution and least cost economic despatch optimization. Losses were then aggregated hourly to produce annual loss volumes.

Next, a second PROMOD IV simulation was performed over the study period with the loss optimization feature active in the despatch solution. In this simulation the model calculated incremental loss factors for each generating station in each hour and included the marginal cost of losses in the unit despatch cost. These unit loss factors were then aggregated by zone and by season for each year to produce the seasonally adjusted TLFs that are a primary focus of the study.

Finally, a "Change Case" simulation was performed by adding the computed Transmission Loss Factors back into the Base Case data to simulate the impact of P229 on system operation. In this case, the TLFs are input as unit cost adjustments that are constant across all generators in a zone. As in the Base Case, the Change Case did not optimize for transmission losses in the despatch (as the TLFs are set *ex ante*), but calculated total system losses hourly to produce annual loss volumes that can be compared back to the base case.

The application of TLFs made units that have a positive impact on losses more expensive, causing them to run less and thus reducing overall system losses in the Change Case. The net result is that the change in production cost is the benefit from the application of the TLFs of P229.

A comparison between the Base Case and Change Case provides a detailed, robust assessment of the impact of P229 on system operation and cost. The full hourly calculation of system losses over all transmission lines provides a robust measure of the annual loss reduction that results from applying TLFs. The benefits of P229 (from the load flow modelling) are then the net reduction in production costs. The net of production cost savings from loss reduction and redespatch costs are already incorporated into the production cost total differences from the procedure described above.

It should also be noted that by using the detailed Ventyx solution, a number of factors, such as changes in fuel charges from changes in the locational mix of plant/despatch, are fully accounted for and internalised within the model. Locational-specific fuel charges are already incorporated into the reference case data, and so the economic despatch and production cost changes include these changes in the aggregate.

Additional details of the assumptions for the modelling, such as fuel and currency price forecasts, are found in the next section.

2.3 CBA

This sub section gives details on our approach applied to the cost-benefit analysis.

At a high level, the costs and benefits of the proposed changes were estimated to be a function of:

- Implementation costs
- Increased costs of generation vis-à-vis the change in despatch given the new set of TLFs.
- Increases in other ancillary costs such as fuel charges based on the change in generation.
- Changes in emissions: CO_2, NOx, SOx.
- Reduction in total transmission system losses

The TOR required that we only consider the perspective of the industry in terms of the cost benefit analysis.

The modelling is done in terms of the net difference between a 'base case' and a 'change case', holding all input assumptions constant between the two, with the base being the "current TLF/TLM regime in the BSC" and the change case being "the new TLF/TLM regime under P229", i.e., seasonal-zonal TLFs.

It should be noted that the net impact of loss reduction and redespatch and CO_2 emissions, gas transport charges, etc, is wholly optimised and internalised by the model and the net change in total production cost per annum is the level of aggregation used (wholly containing the net change in all these factors between the base and the change case).

The methodology is then to discount the predicted cashflows[4] and net benefits from the proposed change of P229.

Equation 1: $$NPV = \sum_{t=1}^{10} \left(\Delta PC_t + IC_t\right)\left(\frac{1}{(1+r)}\right)^t$$

The above equation says that the Net benefit is the change in production cost (production cost savings) plus implementation costs (a negative number) from the base to the change case discounted and summed over each year 2011 to 2021. The '*r*' in the discount rate is the pre-tax WACC.

In many cost benefit analysis, it is common to look at a number of factors such as impacts on taxation, opportunity costs of capital and labour, multiplier effects, etc. However, the terms of reference required that the level of the analysis should be at the electricity sector, so these factors were not modelled for the purposes of this study.

The CBA basis above includes CO_2 cost changes, as these are wholly internalised in the model and priced according to EU ETS price forecasts. It does not however include other emissions such as SOx and NOx. Including these as the change in the value of SOx and NOx (*VSOx* and *VNOx*) emissions gives:

Equation 2: $$NPV = \sum_{t=1}^{10} \left(\Delta PC_t + IC_t + \Delta VSO_x + \Delta VNO_x\right)\left(\frac{1}{(1+r)}\right)^t$$

Additional details about the method for the estimation of the parameters such as r are contained in the next section.

[4] Some of the benefits, such as non-priced emissions changes, do not involve explicit cashflows.

3 Estimation of inputs to the CBA

3.1 Implementation costs

3.1.1 Costs based on new data received from Elexon

An element of the cost benefit analysis is the cost of implementation of P229. The main elements of this are expected to be IT and person-day related costs from updating BSC IT systems, billing systems linked to metered volumes, etc, so that these would reflect the new zonal and seasonal TLFs.

As part of the project, Elexon requested that BSC participants respond to a questionnaire to give their estimates of the implementation costs. Questionnaire responses were received from 11 companies. A summary table of the responses can be found below.

Table 3-1 : P229 Assessment Phase Impact Assessment Responses

Company	Implementation Period	Estimate
International Power Mitsui	10 Working Days	N/A
Total Gas & Power	6-9 Months	N/A
ScottishPower	8 Months	£200,000
E.ON UK	9 Months	N/A
EDF ENERGY	12 Months	£300,000 - £600000
Western Power Distribution	Minimal	N/A
GDF Suez Energy UK	6-9 Months	£150,000
RWE Trading GmbH	Minimal	N/A
Drax Power Limited	12 Months	N/A
British Energy Trading & Sales Ltd	9 Months	£100,00 - £300,000
Centrica	Minimal	< £10,000

Source: Elexon

As can be seen in Table 3-1, there is significant variation in the cost estimates expressed. Two of the main reasons for this appear to be that a number of companies have not, as of yet, run an internal impact assessment on the cost of introducing the proposed modifications (or have and have not made the information available to the questionnaire), while some companies have already made some of the required operational changes based on previous modification proposals.

In order to estimate the aggregate industry cost, we scaled up (to reflect missing data) the figures provided by the list of companies above, with some requisite assumptions. Given that we are looking for the total cost of implementing the modifications, estimates which did not account for any work done to date were excluded from the sample. Estimates provided in terms of man-days were converted into annual £ values using data from the Office of National Statistics (ONS) on average weekly wages for employees in the energy utility sector, while the mid-point was used for all companies that provided a cost range. From here, and average cost per-megawatt value was calculated for each company, based on 2008 data from the Department for Business, Enterprise and Regulatory Reform (BERR) Digest of UK Energy Statistics 2008. Finally, this figure was multiplied by the total industry plant capacity. Based on this methodology, it is estimated that the combined cost of the P229 modifications to the industry would amount to £3.42million. Table 3-2 shows the range of potential industry costs, assuming costs at the low, high and mid point of bands provided by the respondents.

Table 3-2 : Distributor Cost Estimates of P229 Implementation

	Low Estimate	High Estimate	Mid-Point Estimate
Cost per MW	£35.78	£51.97	£43.88
Total	£2,791,761	£4,055,164	£3,423,463

Source: LE/Ventyx

In addition to the implementation costs from the BSC participants, there are implementation costs for central BSC systems and processes. Elexon have provided them in the table below. It is noteworthy that these costs were confirmed by Elexon to be the net additional cost of P229 if seasonal and zonal TLFs were to be implemented. These do not include any existing operational costs in the absence of P229.

Table 3-3: P229 Implementation Costs			
		Cost	**Tolerance**
Logica CSA Cost	Total	£31,000	+/- 10%
TLFA/Load Flow Model Reviewer Cost	Development, Testing and Deployment	£250,000	+/- 50%
TOMAS	Development, Testing and Deployment	£15,000	+/- 100%
BSC Audit Cost	Planning and Development	£15,000	+/- 50%
Implementation Cost	External Programme Audit Design Clarifications Additional Resource Costs Additional Testing/Audit Support Costs	£0 £2,500 £0 £20,000	Nil +/- 100% Nil +/- 50%
Total Demand Led Implementation Cost		£318,500	+/- 50%
ELEXON Implementation Resource Cost		426 man days £93,720	+/- 5%
Total Implementation Cost		**£427,220**	**+/- 35%**

Source: Elexon

Table 3-4: P229 Ongoing Support and Maintenance Costs		
	Cost	**Tolerance**
Logica CSA Operation Cost Per BSC Year	£1,550	Nil
TLFA/Load Flow Model Reviewer Operational Cost Per BSC Year	£100,000	+/- 50%
BSC Auditor Cost Per BSC Year	£40,000	+/- 50%
ELEXON Operational Cost Per BSC Year	70 man days £15,400	+/- 5%
Total Operational Cost Per BSC Year	**£156,950**	**+/- 45%**

Source: Elexon

3.1.2 Previous estimates of implementation costs

It is useful to compare the current results with previous estimates. As part of the previous review of zonal TLFs, BSC participants gave estimates to Elexon's contracted consultants Oxera of implementation costs. Therefore, one way of estimating implementation costs would be to take these estimates and adjust them for inflation, any material changes in the structure of the industry such as the number of BSC participants.

The total implementation costs of the previous study can be found from the following table. Using the all items UK CPI index from ONS between 2000 and 2009 would inflate the below cost estimates by 20%, or give £2.48m.

Table 3-5: Estimated implementation costs (£ '000)

	Cost	Tolerance
Vertically integrated generators	896	± 50%
Other generators	528	± 100%
I&C retailers (not captured within generators)	132	± 100%
Total market participants	**1,556**	**± 70%**
Transmission company costs	40	-
Central costs	467	± 35%
Total	**2,063**	**± 60%**

Source: Oxera calculations

3.1.3 Total overall implementation costs

The total implementation costs, taking the mid-point of our estimates and Elexon's, is £3.85m (£3.42m + £0.43m) plus £0.157m ongoing annual costs.

3.2 The discount rate for CBA

3.2.1 Discussion of discounting

The discounting of costs and benefits for the potential changing of the TLFs regime in GB requires a discount rate. There are a number of options with respect to choice of discount rate methodology, including: social rates of discount, HM Treasury Guidelines, EU Commission Guidelines and weighted average cost of capital (WACC).

In our proposal to Elexon and in subsequent presentations and discussions with the P229 Modification Group, it was agreed that a WACC approach, relying primarily and where appropriate, on WACC parameters from Ofgem regulatory decisions, would be used. WACC and WACC estimation is a fairly well-researched topic and we have proposed to the P229 Modification Group to rely primarily on the Ofgem methodology from recent price reviews, with the possible adjustment of particular parameters for market related risk or changes over time (e.g., a generation company versus a regulated transmission company might have different WACCs).

Therefore, for the purpose of discounting, we are using a weighted average cost of capital (WACC). Previously, OXERA relied on a discount rate from HM Treasury's Green Book guidelines, but this was criticised by Ofgem's consultants as possibly too low a discount rate. Given that these are private companies, we proposed to use a WACC (as opposed to the HM Treasury value).

There are nonetheless still potential issues with the WACC estimation and with choice of parameters and models (for example, whether to use a post tax or pre-tax WACC, real or nominal, etc). In addition, it may be that Ofgem, Elexon, or the Modification Group subsequently decide to use a social rate of discount or HM Treasury Guideline rates. The rest of the section discusses briefly the WACC methodology and parameters, discusses the issue of pre-tax and post tax, and compares and contrasts WACC results with other discount rates.

3.2.2 Review of some of the basics of WACC and introduction of the parameters

This section describes the basics of the cost of capital estimation in a step-by-step building block approach. It presents the "post-tax" form (most commonly used) of the WACC. The section starts with some principles and an introduction to some of the fundamental assumptions of the model.

Basic framework of the post-tax WACC

The approach that has been adopted by a number of regulatory bodies, including the Office of Gas and Electricity Markets (OFGEM), the Office of Fair Trading (OFT) and the Competition Commission (CC) in UK, the Commission for Energy Regulation (CER) in Ireland, and Public utility commissions in North America. The general approach to the WACC estimation utilises the Capital Asset Pricing Model (CAPM) within the framework of the Weighted Average Cost of Capital (WACC). The WACC can be defined as:

Equation 3.1 $WACC = g \times r_d(1-t) + (1-g) \times r_e$

Where: g is the level of gearing, i.e. debt as a proportion of total asset value;

r_d is the company's cost of debt finance; and

r_e is the company's cost of equity finance.

If the CAPM is inserted into the WACC, and the cost of debt is defined, the following relationship is found:

Equation 3.2 $WACC = \lfloor g \times (r_f + DP)(1-t) \rfloor + \{(1-g)\lfloor r_f + \beta(r_m - r_f)\rfloor\}$

Where: r_f is the risk-free rate of return;

DP is the debt premium paid by the company;

r_m is the market rate of return—(r_m-r_f) is often referred to as the equity risk premium;

β is the measure of the risk premium required by investors to hold the company's equity. Under CAPM, it is a measure of risk relative to the market;

g is the level of gearing, i.e. debt as a proportion of total regulatory asset value; and

t is the UK corporate tax rate.

Equation 3.2 provides five of the key elements of the cost of capital. The main variables in WACC calculation are risk-free rate, debt premium, equity/market risk premium, beta and gearing. The risk free rate and the debt premium determine the cost of debt whereas the risk free rate, beta and the market rate of return determines the cost of equity.

For the purpose of this report our analysis of these variables will draw primarily, as a comparator, from the experience of OFGEM in relation to their transmission Price Control Review (TPCR) undertaken as well as information from the current distribution price control. It is however important to note two aspects in relation to this; firstly, some of the parameters should be updated over time, such as the risk free rate of interest, inflation rate, etc.

3.2.3 Review of Ofgem's most recent transmission price control

3.2.3.1 TPCR December 06

The current price control for transmission investments in GB is from 2007. The Ofgem price control for transmission (TPCR December 2006 Final Proposals[5]) decided on the following values for the cost of capital.

r_f -- the risk-free rate: 2.5%

DP --the debt premium: 1.0 to 1.5%

r_m -- the market rate of return premium—(r_m-r_f) or the equity risk premium: a long run return to equity consistent with DPCR4 6.5% to 7.5% (less the 2.5% risk free rate), gives a premium of 4.5 to 5.5%.

β -- the measure the market undiversifiable risk: 1.0

g -- the level of gearing: 60%

t --the UK corporate tax rate: 30% (we note that we will use the new tax rate of 28%)

[5] Available at http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/16342-20061201_TPCR%20Final%20Proposals_in_v71%206%20Final.pdf

Table 3-6: : Ofgem WACC TPCR Policy Review December 06		
	Updated Proposals %	**Final Proposals** %
Risk Free Rate	2.30	2.50
Debt Premium	1.10	1.25
Cost of Debt	3.40	3.75
Cost of Equity	7.00	7.00
Gearing	60.00	60.00
Tax	30.00	30.00
WACC (real pre-tax)	6.00	6.25
WACC (vanilla)	4.84	5.05
WACC (after tax at 30%)	4.20	4.40
Source: LE/Ventyx		

3.2.4 DPCR5

The most recent distribution price control review is now underway and Ofgem is consulting on the various issues including the cost of capital[6]. We consider the transmission price control to be the most appropriate, however, it is useful to consider this more recent work to assess insights into how financial market conditions might have changed (although we note that these are long-run discount rates we should use for P229). It is still useful to consider DPCR5 because it addresses current financial market condition issues from the regulatory cost of capital perspective.

In summary, Ofgem recognised that financial challenges face the market, but the net effect of lower BOE interest rates and higher debt spreads[7] is still unclear, plus Ofgem noted the fact that distribution companies still have investment grade credit ratings (and also that Discos might be able to gear even higher than 60%). They propose that their final decision would be based in part on a close monitoring of how financial markets evolve over 2009.

[6] Details can be found at http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/POLICY%20PAPER%20DOCUMENT%20File%20problem%20use%20this%20one%2020081126%20PR.pdf

[7] It is noteworthy that many debt spreads have fallen from the period from March to June 2009.

In conclusion to our work, we do not find any particular evidence to deviate from the TPCR data.

3.2.1 HM Treasury Guidelines

The HM Treasury Green Book gives guidelines for CBA analysis and discount rates[8]. This was the approach used in the previous modification proposal study commissioned by Elexon[9]. The rate used was 3.5%, which is a real rate of discount.

We also note that for some costs and benefits, such as climate change investments, studies have noted that the social rate of discount might be even lower, even zero percent[10], and naturally some of the benefits that might arise from P229 would include reductions in emissions. Thus, by using a WACC and applying it uniformly across all costs and benefits, especially to some emissions reductions, we would argue that the discount rate chosen is more likely to be conservative towards the high-side.

3.2.1 Adjustments to WACC and discount rates

It is important to consider whether the WACC from TPCR or the HM Discount rates would be likely to over or under estimate the appropriate rate of discount for the CBA for P229.

It was suggested by members of the Modification Group panel that the Ofgem TPCR WACC would be too low as it did not account for extra risk of being a merchant generator.

We would note, however, that on the face of it, idiosyncratic or non-market correlated risk is in general, considered to be diversifiable, and so should not receive a risk premium. Only the portion of being a merchant generator which is correlated with 'the market' should attract a premium according to the CAPM.

[8] HM Treasury (2003) "Green Book" Appraisal and Evaluation in Central Government. Available from http://greenbook.treasury.gov.uk/

[9] Oxera (2006), "What are the costs and benefits of zonal loss charging."

[10] MARC D. DAVIDSON, A SOCIAL DISCOUNT RATE FOR CLIMATE DAMAGE TO FUTURE GENERATIONS BASED ON REGULATORY LAW. Available at http://www.hm-treasury.gov.uk/d/climaticchange.pdf

To assess the WACC further, we considered the main parameters from TPCR Ofgem that might be adjusted are the beta and the debt premium. We discuss the parameters to use in the subsections below.

3.2.1.1 Real risk free rate

Since BOE interest rates have come down, the real risk free rate of Ofgem TPCR might be considered high (for today's market rates) at 2.5%. An appropriate comparable risk free security would be a 10-year gilt rate. In light of (by historical standards) large borrowing by the UK Government the recent rates rose to a seven week high of 3.52% (23 April 2009)[11] while 2 year gilts were at about 1.3%. The BOE discount rate is 0.5%.

Since market debt rates are in general nominal (although there are inflation indexed instruments), we should subtract current and future expected inflation to get the real rate. According to the BOE[12] the current rate of CPI inflation is 2.9%. Given borrowing levels, low interest rates and the devaluation of sterling, and the steepening of the yield curve, it could be argued that inflation expectations would not be for much lower. Similarly, according to the UK Debt Management Office (UK DMO), yields on index-linked gilts are currently about 3.3% to 3.7% for gilts dated to mature between 2017 and 2021. This would imply a real risk free rate of about 3.52-2.9% = 0.62%. Using RPI and an average of past 3 months gilt rate would give a real risk free rate of between 1 and 1.5%.

3.2.1.2 Beta and the cost of equity

The beta of a company would be higher if the level of non-diversifiable risk associated with being a particular type of player in the market was higher for transmission system *users* than for the regulated transmission system owner. While we would accept that the overall level of risk is probably higher for a generation company or a supply company, it isn't clear that this risk is market correlated; in other words the added risk might be diversifiable, and thus not justify a risk premium.

To gain further insight on this, we undertook analysis of betas from electricity generation and supply companies.

[11] www.euroinvestor.co.uk

[12] http://www.bankofengland.co.uk/

Evidence from company data was studied by London Economics using data from the Bloomberg Professional data terminal service (BB). BB publishes betas for listed companies. Comparisons require unlevering and relevering, as raw betas reflect current company-specific levels of gearing. Using a gearing level of 50% to 60% and a selection of company betas suggested a UK generation company asset beta of about 0.7 and a levered beta of about 1-1.1. However, the degree of undiversifiable risk with respect to P229 might indicate a lower beta.

We believe therefore that a conservative mid-point estimate of beta would be 0.75 and there is no reason to change the Ofgem equity premium, which is a long term concept. However, to be consistent with our initial proposals to the Modification Group, we will use the Ofgem beta of 1.

3.2.1.3 Debt premium and cost of debt

The financial crisis has meant that current yield spreads on corporate debt for generation, supply and integrated utility companies have become significantly larger. Analysis of BB data on yields for corporate debt over the last 6 months for investment grade rated debt instruments indicated a yield spread of between 200-350 basis points (2.0 to 3.5% points). It is noteworthy that as the credit crunch eases these spreads should be expected to fall[13].

Looking thus at adding a higher (current debt spread) of between 200 and 300 basis points to a lower real risk free rate (0.5% to 1.0%), would give us a cost of debt in the range of approximate 2.5% to 4.0%. This said our belief is that the Ofgem TPCR real cost of debt estimates of 3.75% are correct and conservative. In other words, although the debt premiums for company debt might have risen due to the financial crisis, the real risk free rate has fallen considerably too, as both interest rates (BOE rates, LIBOR, other rates) have fallen well more than inflation, making real rates quite low.

The result is that we do not believe any additional adjustment is needed to the Ofgem TPCR 06 cost of debt, and if anything, we believe this figure could come down.

[13] As evidence of the easing, see www.bloomberg.com which at the beginning of May said that USD Libor rates had fallen to levels close to those seen prior to the credit crunch.

3.3 WACC Results

The results of our estimation yields WACC on a pre-tax and post-tax basis that is very close to the Ofgem TPCR. The lower tax rate makes the pre-tax WACC slightly higher and the post tax WACC slightly lower.

Table 3-7: Ofgem WACC TPCR Policy Review December 06

	Ofgem Final TPCR %	LE Updated %
Risk Free Rate	2.5	2.5
Debt Premium	1.25	1.25
Cost of Debt	3.75	3.75
Beta	1	1
Equity Premium (Ofgem Implied) LE Estimate	4.5	4.5
Real Cost of Equity	7	7
Gearing	60%	60%
Tax	30%	28%
WACC (real pre-tax)	6.25	6.14
WACC (after tax at 30% (Ofgem) 28% (LE))	4.375	4.42

Source: LE and Ofgem

A potential issue is whether the results of the CBA should be discounted on a pre-tax or a post-tax basis. We believe that the appropriate rate of discount is the post tax WACC. A pre-tax WACC would be applied to profits that were taxable. Our primary rationale for this is that the system losses that will be saved are the primary drivers of the benefits and these are not taxable. In other words, saving system losses, assuming competitive despatch, should not result in greater profits for generators on the whole; it should lower total system fuel use and lower the total cost of electricity to consumers (and also lower overall emissions, etc). Thus the benefits of P229 would not show up as profits on a pre-tax basis. Discounting them at the higher pre-tax WACC would potentially bias the CBA against making a choice that makes everyone better off. It should nonetheless be recognised that the existence of taxation generally means that social discount rates might deviate from private ones.

Thus the discount rate we use for our CBA is 4.42%. In order to assess the sensitivity of the overall results to the discount rate, two additional discount rates are considered. We use the 3.5% of the HM Treasury 2003 Green Book and allowing for the current uncertainty in debt markets arising from the global financial crisis, a debt premium of 300bp is included in the WACC calculations giving a high end real after-tax WACC of 5.2%.

The question of how the higher WACC was arrived at is of relevance. We undertook considerable analysis of the assertion that WACC figures for, say, merchant generation companies, should be considerably higher than for say, transmission or regulated companies. While this may be the case, we based the added sensitivity on WACC on the only parameters of the WACC formula that are sensitive to risk; beta and the debt risk premium.

With regards to the beta, it should be again noted that this is the measure of non-diversifiable risk in any given company. Thus, risk that is 'idiosyncratic' or non-market correlated, which one might posit is akin to merchant generator risk, would not be expected to attract a risk premium under the standard formulation of the CAPM and the WACC.

A somewhat informal study of current and past betas for major generation companies that are active in the UK market would tend to confirm this. For example, the current beta of EdF, as listed in August 2009 on www.FT.com is 0.79. This is with gearing of about 68% according to the same source; considerably higher than the 50/50 ratio of our estimates (higher gearing would tend to lower the WACC). Similarly, looking at GdF Suez's beta gives a value of 0.96 on gearing of 38%, E.ON a beta of 0.93 on gearing of 50%, Scottish and Southern a beta of 0.64 on gearing of 74%, , RWE 0.61, etc. Previous work by LE studying betas across the EU and Americas for merger and EC State Aid cases has tended to confirm the general levels; beta for major EU generation companies tends to be near and less than 1. The upshot is that the appropriate beta for generation companies is not likely to be higher than one, and thus by using a beta of 1 we are using a beta that is considerably higher than what market information might otherwise suggest.

Thus the only source of higher risk we consider is a higher debt premium. The debt premium we assumed to come up with the higher WACC scenario is 300 basis points. This is more than double the 1.25 debt premium assumed for the Ofgem analysis and we believe appropriate. Many large energy companies were able to borrow at premiums that were lower than this even at the height of the financial crisis. We note that these spreads have been falling as of recently. We nonetheless believe that a debt premium of 300 basis points is quite reasonable in terms of being significantly higher than the value we chose for the reference scenario, and still being reasonably likely for a normal 50/50 geared company. It should also be noted that we did not consider a junk level debt premium or premium for companies that were highly geared or companies that were in financial stress.

3.4 Demand response to price changes—electricity price elasticity

3.4.1 Introductory discussion of demand-side impacts and price elasticity of demand

Estimation of demand-side impacts requires an estimate of the price elasticity of demand.

In general, changes in electricity price will in the long run impact the quantity of electricity consumed. Customers react to changes in observed prices by adjusting their desired quantity of demand. As prices rise, customers will reduce the quantity demanded, while a reduction in prices should lead to an increase in the quantity demanded by customers. The responsiveness of customers to price changes is characterized by their price elasticity of demand; the percentage change in the quantity demanded as a result of a given percentage change in the price.

A significant body of research has been devoted to measuring customers' responsiveness to changes in electricity price. While the degree of price elasticity estimates vary between industrial, residential and commercial electricity customers, all three have been shown to respond to the price signals they face. This response is crucial to the allocation of electric resources in periods of peak demand. However, many end-customers face a fixed retail price and have little incentive to react to fluctuations in the wholesale price of electricity.

A distinction can be made across the time periods in which customers can react to changes in electricity prices. In the short-run, customers must use their existing infrastructure, technologies and resources to respond to price movements. Consequently, their ability to react to the changes in the price is lower in the short-run than in the long-run, where customers can adapt by altering their resources and infrastructure. As more substitution can take place when more time is given, demand for a given product which allows little time for substitution will fluctuate less than when more time is allowed for substitution.

3.4.2 Literature review on demand response

In a review of energy demand for the Northern Ireland Authority for Utility Regulation[14], Smith and Bailey use cointegration methodology to estimate both short-run and long-run elasticities. Including variables to account for the price of electricity, the price of other energy types, income levels and once-off shocks, short run price elasticity is estimated to be -0.3047, suggesting that a 10% increase in the price of electricity would result in a fall in short-run demand of 3.047%. Long-run elasticities were found to be slightly greater (in absolute terms), at -0.3157.

Green (2004)[15] develops a thirteen-node model of the English and Welsh electricity transmission system, incorporating losses and transmission constraints, to determine the optimal nodal price and the associated welfare gain. Included in the analysis are 10 sets of seasonal demand curves for electricity generation, representing different load levels, obtained by scaling down the regional peak demands by a common factor, chosen to match points on the seasonal load-duration curve. From these curves, demand is found to be price sensitive, with a constant elasticity of -0.25 across all nodes.

[14] Smyth, M. & Bailey, M., "An Economic Analysis for the Elasticity of Demand for Energy in Northern Ireland", School of Economics & Politics, University of Ulster, for Northern Ireland Authority for Utility Regulation, 2008

[15] Green, R., "Electricity Transmission Pricing: How much does it cost to get it wrong?", Cambridge Working Papers in Economics, UNIVERSITY OF CAMBRIDGE, 2004

In a paper commissioned by the National Electricity Market Management Company of Australia[16], the National Institute of Economic and Industry Research estimate own price elasticity of demand for electricity in National Electricity Market (NEM) regions. Analysing only the long-run elasticity, the sample was split across residential, commercial and industrial sector demand for electricity. Residential price elasticities were found to be lowest, with a value of -0.25, while commercial and industrial elasticities were broadly similar, estimated at -0.35 and -0.38 respectively. A value for the price elasticity of demand for the entire NEM region was also estimated, with a mean value of -0.35 and a range of -0.2 to -0.5.

Dahl (1993)[17] estimated demand for electricity in the US using 2 aggregate demand, 21 residential, 7 commercial, and 18 industrial studies of the price elasticity of electricity. While there was a significant amount of variance in price elasticity estimates, long-run price elasticity for aggregate electricity demand was found to be near -1.0, with long-run price elasticity for the residential sector between -0.75 and -0.91.

A recent study of households demand for gas and electricity by Oxford Economics (2008)[18] used an ordinary least squares (OLS) model to determine the long-run relationship between fuel demand and the number of households, disposable income, winter degree days, fuel prices and general structural trends. The equation explained approximately 80% of the variance in electricity demand, with the long-run price elasticity estimated to be -0.1.

Hunt and Witt (1995)[19] estimate an aggregate energy demand equation for the UK using maximum likelihood techniques and data from 1967-1994. The underlying model incorporates the real price of energy, real incomes and the temperature in January of each year, to estimate aggregate final user energy consumption. Imposing exogeneity restrictions, their long run estimate of price elasticity of demand is -0.286, similar to the value of -0.3 obtained by Hunt and Manning (1989) from an older dataset.

[16] The National Institute of Economic and Industry Research, "The own price elasticity of demand for electricity in NEM regions", A report for the National Electricity Market Management Company, 2007

[17] Dahl, C.A., "A survey of energy demand elasticities in support of the development of the NEMS", 1993

[18] Oxford Economics, "Estimation of households' demand for gas and electricity", 2008

[19] L.C. Hunt & Witt, R., "An Analysis of UK Energy Demand Using Multivariate Co-integration," Surrey Energy Economics Centre (SEEC), Department of Economics Discussion Papers (SEEDS), 1995

A summary of overall energy demand elasticity estimates for the UK was compiled by Oxera[20] in 2006. They examined two alternative energy-cost shock models; a general equilibrium model that uses a detailed framework for estimating the sector by sector trade-off between energy changes and economic growth, and a two part model incorporating a macroeconomic system which specifies the economic environment in which energy markets are operating and a separate energy system which calculates the retail prices, demands, and supplies of the major energy sources. From these models, Oxera concluded short-run price elasticity to be -0.3, while long-run elasticity falls between a bound of -0.2 and -0.6.

Table 3-8 presents a summary of the estimated values from the major energy elasticity estimation studies.

Table 3-8: International Price Elasticity Estimates for Energy

Source	Sample	Short-Run Elasticity	Long-Run Elasticity
NIAUR UU Report (2008)	Northern Ireland Industrial/Commercial/Domestic	-0.3047	-0.3157
Green (2004)	England & Wales Generation Price	-0.25	
Dahl (1993)	US Industrial/Commercial/Domestic		-1
Philip Wright	UK Residential	From -0.16 to -0.22	
Paul, Meyers and Palmer (2009)	US Industrial/Commercial/Domestic	-0.13	-0.36
Oxford Economics (2008)	UK Residential	-0.06	-0.11
Hunt and Witt (1995)	UK Industrial/Commercial/Domestic	-0.151	-0.286
Oxera (2006)	US Industrial/Commercial/Domestic	-0.3	From -0.2 to -0.6

Source: LE analysis of current literature

[20] Oxera, Modelling the macroeconomic effects of energy policies, Report prepared for Department of Trade and Industry, 2006

Conclusions with respect to an elasticity estimate for the purposes of our study present some challenges. However, the point of long-run versus short run is probably mostly moot, as most studies seem to come up with a fairly similar number for the long and the short run elasticity. Further, while the precise value is no-doubt uncertain, some certainty emerges from the existing data that the likely range of elasticity estimates is about -0.1 to -0.3. We further note that for the previous study, Oxera used elasticity estimates of -0.15 (Domestic) and -0.25 (I&C)—low scenario, and a high scenario of the same respectively of -0.35 and -.45. They did not have data on demand by zone to split into domestic and I&C so split this on an assumed basis (33:67). The same problem presents itself here. We preferred to simply use a judgement of elasticity of -0.25, as a central scenario. We performed a sensitivity of this, but essentially the overall CBA and results were not sensitive to assumptions about demand elasticity.

3.5 Environmental outputs and non-market-priced outputs

A key factor in determining the cost/benefit of implementing P229 is the impact these changes will have on the level of emissions production from the associated power plants.

3.5.1 GHG emissions and prices

For GHG emissions, we focus only on CO_2 emissions. The CO_2 emissions from power plants in the UK are endogenously estimated by the model. EU ETS permits are assumed to set the reference price for CO_2. The prices for EU ETS allowances is estimated by Ventyx and is based on spot and forward curve data of actual traded allowances. More details of these prices are contained in the section on the description of the reference case.

3.5.2 Nitrous Oxide (NOx) and Sulphur Dioxide (SOx)

In addition to CO_2, most conventional power stations are responsible for a number of additional emissions, two of which contribute to significant environmental degradation, mainly through smog and acid rain; Nitrogen Oxides (NO_X) and Sulphur Oxides (SO_X). These emissions are considered to be two of the most potentially damaging emissions in relation to environmental damage, and human health, as well as being responsible for causing urban smog (NO_X) and acid rain (SO_X).

NO_X emissions are produced by two separate mechanisms during combustion, the "fuel NO_X" related to the nitrogen content of the fuel and combustion conditions, and the "thermal NO_X" resulting from the chemical formation of NO from N_2 and O_2 at temperatures exceeding 1,400°C. With regard to energy generation, there are three main factors that determine NO_X emissions levels:

- Fossil Fuels (by both type and quantity used);
- Technology Type;
- Pollution Control Technology.

According to the UK Emission Factors Database, standard NO_X emission factors of power plants by fuel source range from 0.0000106 kilotonnes per megatonne of fuel for natural gas plants, to 0.629 kilotonnes per megatonne of fuel for coal fired power plants.

In comparison, SO_X emissions are only produced by the combustion of fuel containing sulphur compounds. As a result, SO_X emissions from fossil fuel combustion are easier to calculate than NO_X emissions. Emissions levels are primarily determined by:

- The Heat and Sulphur content of the Fuel;
- The Thermal Efficiency of the Plant.

As with NO_X estimates, emissions factors for SO_X are available from the UK Emission Factors Database, and range from a minimum of 0.0000239 kilotonnes per megatonne of fuel for natural gas power plants, to 14 kilotonnes per megatonne for standard fuel oil power plants.

For all estimates provided below, values have (where necessary) been converted into 2009 Sterling values. This has been achieved by adjusting pre 2009 figures using appropriate rates of inflation and/or converting from non-sterling denominated currencies into British pounds. Rates of inflation were taken from the Office for National Statistics website[21], while conversion from foreign currency to Sterling was done using Purchasing Power Parity estimates taken from the Organisation for Economic Cooperation and Development (OECD) Statistics Directorate[22], with Euro zone values based on a composite of French and German Purchasing Power Parity figures.

[21] For more information, see: http://www.statistics.gov.uk/

[22] For more information, see: http://www.oecd.org/std

Although NO_X and SO_X emissions are not universally subject to a cap and trade system, a number of countries have limited the maximum allowable output of both using an emissions trading scheme similar to the carbon system. Correspondingly, exchanges such as the Chicago Climate Exchange and the European Climate Exchange trade various forms of NO_X and SO_X emissions permits. Data from the Regional Clean Air Incentives Market (RECLAIM) for 2008 show average traded values for NO_X and SO_X have been priced at approximately $2,800 and $1,423 per tonne respectively.

Estimates of the cost of reducing NO_X and SO_X emissions using Best Available Technology Emission Control Technologies (BATETC) have been applied to the 200 EU27 power stations that account for 80% of all energy-related NO_X and SO_X emissions and 63% of all energy-related CO_2 emissions[23]. At an abatement cost of €3.981 billion for 1,506 kilotonnes of NO_X (90% of current NO_X emissions) and €5.364 billion for 3,659 kilotonnes of SO_X (93% of current SO_X emissions), this is equivalent to abatement costs of €2,643 per tonne of NO_X and €1,466 per tonne of SO_X. For the 3,000 power stations accounting for 100% of all acid emissions from energy generation, these values rise to €5,415 per tonne of NO_X and €2,644 per tonne of SO_X. Summary statistics are provided in Table 3-9.

Table 3-9: Summary of Greenhouse Gas Production and Costs using Best Available Technique Emission Control Technologies (BATECT)

	NOx	SOx
Base kt	1,679	3,920
BAT kt	173	261
Reduction	1,506	3,659
MWe	2,170,000	
£m per Annum	£3,391	£4,569
£ per Tonne	£2,252	£1,249
£ per MW	0.0010	0.0006
Tonne per MW	0.6940	1.6862

Source: UCL Study for Swedish NGO Secretariat on Acid Rain, 2007

[23] Barrett, M., "The Costs And Health Benefits Of Applying Reducing Emissions From Power Stations In Europe", for the Swedish NGO Secretariat on Acid Rain, November 2007

The MethodEx project evaluates the environmental and health externalities accruing from the energy, transport, agricultural, transport and industrial sectors. The methods for these calculations are consistent with the methods used by ExternE, CAFE_CBA and the WHO, which are all broadly similar in most regards. These assumptions have been used to generate damage per tonne (€/tonne) damage estimates for SO_X and NO_X at a national level. Total damages for the regional and global pollutants are calculated simply by multiplying emissions by €/tonne damages. Estimates for low and high case CAFE/WHO externalities, as well as comparable ExternE estimates, are provided below in Table 3-10.

Table 3-10: MethodEx estimates of External Costs per Metric Tonne of Pollutant

	NOx	SOx
ExternE	£2,524	£4,616
CAFÉ/WHO (with sensitivity)	£22,942	£24,363
CAFÉ/WHO (without sensitivity)	£8,947	£8,463

Source: MethodEx

Table 3-11 presents summary values of the cost per metric tonne of both SO_X and NO_X emissions from the above reports. RECLAIM estimates are based on market values for tradable pollution credits, BATECT estimates are based on the associated costs of emissions abatement, while CAFE/WHO and ExternE estimates are derived from the external social cost of the emissions.

Table 3-11: Summary of Cost Estimates per metric tonne of NO_X and SO_X

	NOx	SOx
RECLAIM	£2,734	£1,389
BATECT	£2,252	£1,249
CAFE/WHO	£8,947	£8,463
ExternE	£2,524	£4,616

Source: LE

3.5.3 Conclusion NOx and SOx prices

We synthesized the available information on NOx and SOx prices by taking the average of the RECLAIM and BATECT abatement cost estimates. This gives in £/metric tonne abatement, £2,493 and £1,319 as the production cost based prices of NOx and SOx. The basis of this judgement decision was as follows: the RECLAIM data are based on an actual cap and trade system, and are likely to be as best an estimate of current available technology; this was adjusted for USA to UK exchange rates. BATECT again is based on best available abatement technology. The CAFÉ/WHO and ExternE figures, we believed were a bit high. This may be because they include some estimates of the marginal social damage. This is an extra cost which may or may not be above the marginal producers' abatement cost—and our understanding of our terms of reference suggested that we should focus on the industry perspective without investigating wider costs and benefits for the society as a whole. Whether these figures should be included is debatable. If a market mechanism were available, then at least *a priori and absent high transactions costs* the market would equate the marginal production cost with the marginal social value.

3.5.4 Other externalities

There are other possible externalities with respect to power production besides GHG and acid rain (SOx and NOx) emissions. In focusing on the main emissions, ash, soot, and related particulate emissions, as well as smaller amounts of heavy metals contained as impurities in some fuel types (e.g., mercury in coal).

It is difficult to say with great precision what the value of these many different emissions might be. Further, good references as to the emissions factors would vary with specificities of the coal or fuel type used, and this data is not in general publicly available.

In general, however, we would expect some reduction of these non-primary emissions as the net effect of TLFs and a keener TLF regime is to lower total production by lowering transmission loses. However, there is the possibility that the TLFs regime would encourage shifts to dirtier fuels, merely based on the current historical location of plants of specific fuel types, as non-CO_2 emissions are not internalised by the generators' production decisions.

3.6 Baseline estimates of other factors

A number of factors are estimated qualitatively. Precise quantitative estimates are not possible due to existing data, time and computational limits.

It should be noted that the only relevant factors for the CBA are to estimate the changes in these factors from the "change TLFs case" versus the "base" or business as usual (BAU) TLFs case. Since the changes in the despatch and the losses are actually small and dynamic, it is not expected that the difference in many of the other factors would be large.

3.6.1 Generation plant locational impacts

Generation plant location is determined by a number of factors including the TLFs charging regime. However, any changes to the TLFs regime should only have an impact on generation locational decisions if the TLF's charges are "on the margin", in other words, if the generator is close to locating their plant in either location A versus location B, and A and B are likely to have different TLFs.

Alternatively, other factors tend to drive plant location decisions, including (loosely in order of importance):

- Availability of and cost of land/site
  - Land costs
  - Planning permission, local authority approval, etc
- Fuel source fixed and variable charges
  - Gas connection and shipping charges
  - Coal mine/railroad-link, port shipping for coal, distance to plant
  - Storage, shipping, and delivery charges for petroleum derivative fuels such as fuel oil
- Grid connection
  - Connection charge once-off
  - Use of system charges (per capacity per annum)
  - TLM/TLF zonal loss charge variations
- Other necessities/charges to the extent they vary by region
  - Labour force, contractors, and related costs

- o Material inputs costs; water, non-power use fuel, insurance
- o Taxes, local authority rates, etc.

Any analysis of plant entry that would vary by zone and potentially be impacted by P229 assumes that the plant will have sufficient demand/have sufficiently low cost to sell output on a commercial basis in the existing market and that they satisfy various licensing and regulatory approval.

Given this long and detailed list, it naturally means that lead time for plants can be up to about 3-5 years for conventional thermal plants; likely longer for large renewables and/or nuclear.

A key consideration is that Transmission Network Use of System (TNUoS) charges already have locational incentives built into them to try and incentivize generators to locate at optimal locations with respect to grid connections. This has, over the years, apparently had very little impact on generation locating closer to demand or changing from available sites. The conclusion is that generators are already quite constrained with respect to location, and that locational decisions are apparently little impacted by TNUoS charges. Therefore, TLFs, which are mainly meant to incentivise efficient use of the system with respect to variable losses, might be expected to have an even smaller impact on locational decisions of future potential generators.

3.6.2 Impact on gas transmission tariffs

The impact of the new TLFs regime is not expected to have large or significant impacts on gas transmission tariffs. While again, there will be some shifts in the location of system users, much of the shift will be among existing mid-merit plant, many of which are coal and opt-out plant. Highly efficient baseload CCGT gas plant will not change their production decisions much based on the new regime of TLFs.

3.6.3 Entry, exit, and mothball

Plant entry, exit, and mothball decisions are another area of potential impact for the new TLFs regime proposed by P229. The baseline schedule for plant entry, exit and mothball is part of the Ventyx UK-GB market reference case forecasts. However, it is not expected that the new regime will have significant quantifiable impacts on entry, exit and mothball.

Exit is probably the least likely to be impacted by the new P229 TLFs. Useful life and the cost of maintenance and overhaul are the factors most likely to impact plant exit/decommissioning. Other significant factors include supply and demand, and the efficiency of new technology that has evolved over the life of the plant. These factors are likely to be much larger than marginal impacts of the new proposed TLF regime. The useful life of most plant is, with some range due to maintenance and overhaul, fixed. For some plant, especially peaking plant which might not be used very frequently, the useful life might be much more.

Mothballing of plant is a more special case as the plant location is not being potentially impacted by the change in loss charging, but the decision to run the plant or make it available in say, a year, might be. We would estimate that one of the major factors determining mothballing would be where the plant was sitting in the merit order – how much was it expected to run anyway. If the plant is not expected to run much due to say, temporarily depressed demand, and if labour and other variable O&M costs can be saved then the plant operators/owners might decide to mothball the plant. We would estimate that this decision might only in the rarest of circumstances be impacted by P229.

Therefore, with regards to the above, we have not assumed any impact from P229 on plant entry and exit and mothballing in modelling the course of production and demand over the 10 year time period. In other words, we have not undertaken to iteratively model plant entry, exit and mothballing across years, and then recalculate TLFs, and production cost and losses. Such an exercise would have been prohibitively difficult from a computational point of view, and in our view would not have added much precision to the analysis.

3.6.4 Embedded generation

Embedded generation is generation that is connected at the distribution level.

Embedded generation is typically smaller generation such as Combined Heat and Power (CHP) or renewable generation: small hydro, wind, or biomass.

Essentially, all the demand data and generation data we have received has been at transmission level. Thus, we cannot explicitly model embedded generation, but implicitly, it is modelled as it is already reflected in the current demand data, and the future demand forecasts. It is expected that embedded generation may have an increased impact over the medium term as more renewables and CHP come online.

The generation from such plant is netted off from the demand forecast made by NGC. On the other hand, NGC's forecasts explicitly include demand served by large embedded generation.

3.6.5 Renewables

The expected impact of any change in the TLF regime from the current one to a new seasonal zonal one is not expected to have significant impact in the current expected development of renewables. First of all, it is useful to recall that the impact of the new TLFs regime is estimated as the difference between a base (BAU) case and a change (New seasonal zonal TLFs) case. The resulting differences occur in a trade-off between marginal cost of the generation plant versus marginal cost of the generation plant plus marginal impact on transmission losses (and to the extent the new seasonal zonal TLFs will reflect the 'true' TLFs). However, for renewables, there is no trade-off; the production cost is already zero, so it should always run. (This is true at least in general, for renewables such as wind and basic or run of river hydro; for other hydro, such as pumped and large storage, this might be different).

Naturally, while the total production cost of TLFs will not change under P229, there is the possibility that the charging regime envisaged by P229 would have a negative impact on the total amount of renewables coming online. This would only occur if the available sites for renewables are mostly only in high TLF zones. There are a number of key points with regards to this:

- Large scale renewables are likely to be offshore and on-shore wind, where wind condition and grid and other infrastructure siting factors will be paramount.
- Small scale renewables are more likely to be imbedded in the distribution system, and so would not explicitly face the impacts of P229.

Regardless of the actual impact of P229 on renewables generation siting – we note that a sensitivity case of our P229 modelling is to model an aggressive offshore wind scenario, where offshore wind essentially in fact doubles existing targets.

4 Estimates of inputs to the system modelling—Reference Case Scenario

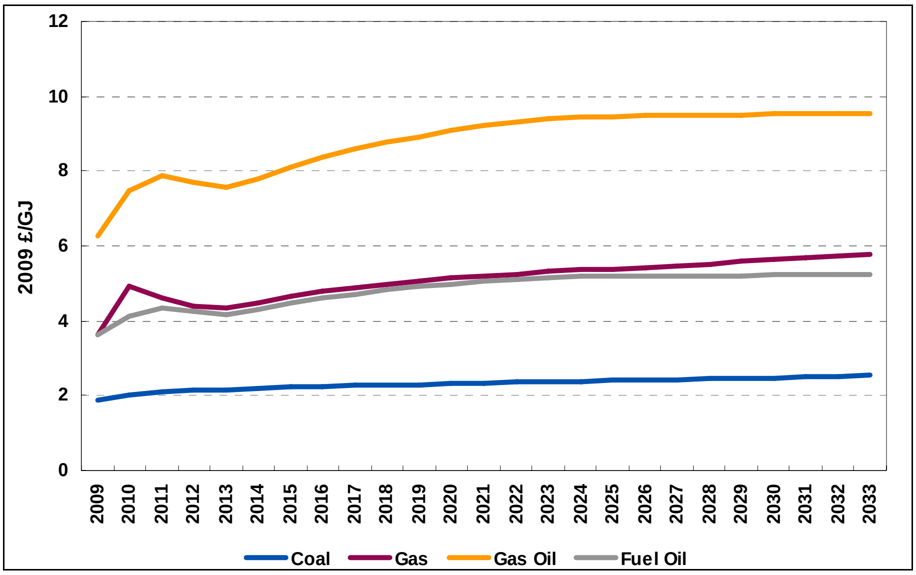
This section describes the estimation of the reference case inputs to the modelling of the Great Britain electricity generation and transmission system.

For all our scenarios, the reference case forms the basis of the forecasts and assumptions for input prices, supply and demand.

4.1 Fuel price forecasts

Forecasting and estimating the CBA of P229 requires a forecast of future fuel prices. The geographical pattern of generation and demand on the current bulk supply system is currently driven in part by fuel prices as well as by location of physical capital that is installed. Naturally, since fuel prices often display seasonality, locational delivery charges, and other such factors then the geographical and intertemporal patterns of fuel prices changes would in general impact on the precise mix of generation at any given time on the system. The methodology used takes into account these locational and seasonal factors for fuel price forecasts used as inputs to the despatch modelling.

Figure 4-1: Long-Term Gas, Fuel Oil and Coal Prices



Source: Ventyx

4.1.1 Base case gas price forecasts

Gas price forecast

Table 4-1: Forecast Annual Average National Balancing Point Gas Prices, 2009[24][1]-2033		
Year	**NBP (£/GJ)**	**NBP (pence/therm)**
2011	4.62	48.74
2012	4.39	46.32
2013	4.32	45.58
2014	4.47	47.16
2015	4.64	48.95
2016	4.78	50.43
2017	4.87	51.38
2018	4.96	52.33
2019	5.05	53.28
2020	5.14	54.23
2021	5.20	54.86
Source: Ventyx		

For generators, the fuel price forecasts used for the P229 CBA models natural gas burner-tip prices as the sum of commodity prices (the cost of gas at the NBP) and all relevant transportation charges involved in transporting natural gas from the market centre to the generation plant. The overview of the locational-specific gas price adders are found in the table below.

Table 4-2: Gas Price Delivery Cost Adders		
Zone	**Adder (£/GJ)**	**Adder (pence/therm)**
GB-East	0.0642	0.68
GB-North	0.0512	0.54
GB-North West	0.091	0.96
GB-Scotland	0.120	1.27
GB-South	0.0932	0.98
GB-Thames	0.0496	0.52
Source: Ventyx		

4.1.2 Coal price forecast

Coal Price Forecast

Coal price forecasts for the P229 modelling also come from Ventyx's reference case. Ventyx's coal price forecast is derived from a blend of coal price forecasts from Northwest European domestic coal, overland imported coal from Eastern Europe, and global seaborne imported coal.

Table 4-3: Forecast Annual Coal Prices		
Year	**Coal (£/GJ)**	**Coal (£/tonne)**
2011	2.08	62.40
2012	2.14	64.20
2013	2.17	65.10
2014	2.19	65.70
2015	2.22	66.60
2016	2.25	67.50
2017	2.27	68.10
2018	2.28	68.40
2019	2.30	69.00
2020	2.32	69.60
2021	2.34	70.20
Source: Ventyx		

For generators, Ventyx models coal burner-tip prices as the sum of commodity prices (the cost of coal at the market centre) and all relevant transportation charges involved in transporting coal from the market centre to the generation plant.

Table 4-4: Coal Delivery Cost Adders		
Zone	**Adder (£/GJ)**	**Adder (£/tonne)**
Coast	0.15	4.50
Inland	0.20	6.00
Far Inland	0.25	7.50
Source: Ventyx		

4.1.3 Oil and petroleum price forecasts

Oil Products Forecast

The long-term prices for GBEM Fuel Oil (Sulphur <1%) and Gasoil are derived from statistically estimated historical product price relationships between Brent prices and product prices reported by the IEA. For generators, Ventyx models Fuel Oil and Gasoil burner-tip prices as the sum of commodity prices and all relevant transportation charges involved in transporting fuel from the market centre to the generation plant and applicable taxes. The values are presented in Table 4-5.

Table 4-5: Forecast Annual Brent Crude, Fuel Oil and Gasoil Prices, 2009[25]-2033			
	Brent ($/bbl)	**Fuel Oil (£/GJ)**	**Gasoil (£/GJ)**
2011	65.37	4.33	7.86
2012	64.12	4.25	7.72
2013	62.66	4.16	7.55
2014	64.87	4.30	7.81
2015	67.35	4.46	8.10
2016	69.53	4.60	8.36
2017	71.40	4.72	8.58
2018	72.99	4.82	8.76
2019	74.39	4.91	8.93
2020	75.64	4.98	9.08
2021	76.71	5.05	9.20
Source: Ventyx			

[25] 2009 average includes May to December.

4.1.4 CO_2 emissions EU ETS prices

CO_2 prices used for the P229 model come from Ventyx's forecasts of EU ETS allowance prices.

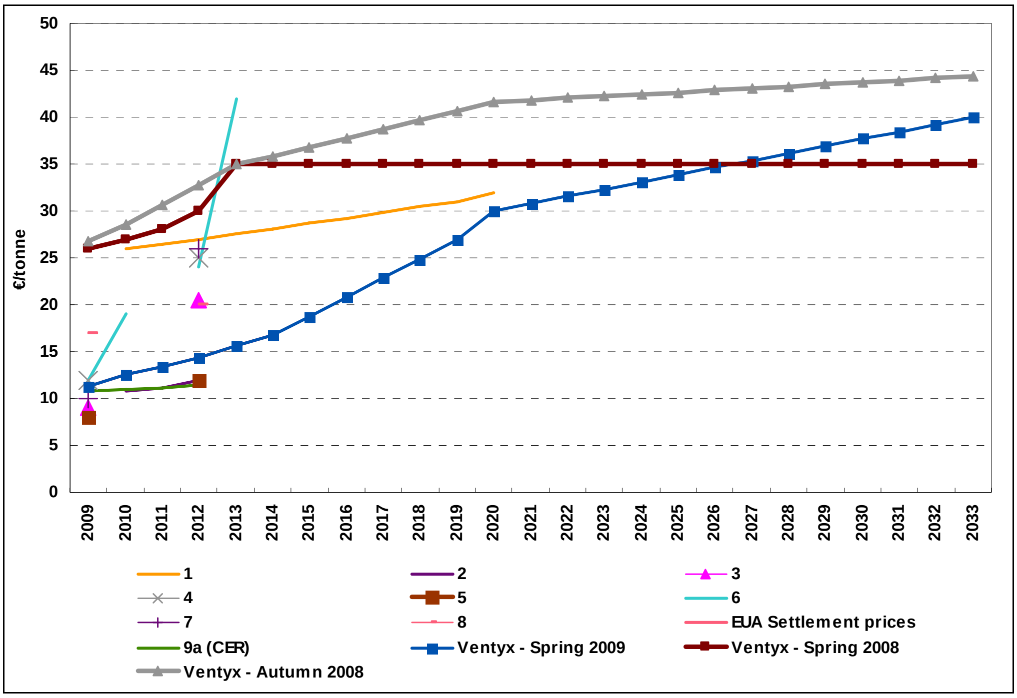
Table 4-6: EU ETS Price Forecast

Year	Euro/tonne
2009	11.31
2010	12.60
2011	13.35
2012	14.37
2013	15.72
2014	16.72
2015	18.76
2016	20.80
2017	22.84
2018	24.88
2019	26.92
2020	30.00
2021	30.60

Source: Ventyx

Ventyx has for this study used the ECX future prices quoted in March 2009 for the years 2009 to 2014; starting with €11.31/tonne in 2009 and increasing to €16.72 in 2014. The CO_2 price is only expected to reach €30/tonne in 2020. Beyond 2020 Ventyx has added an annual growth rate of around 2 percent p.a. out to the end of the study period. As a result, CO_2 prices reach €30.60/tonne by the end of the study period.

Figure 4-2: Carbon Price forecasts[26]



Source: Ventyx

4.1.5 Inflation and exchange rates

Fuel prices are often not quoted in GBP, and so implicit in fuel price forecasts for the GB power sector are forecasts of exchange rates between some major currencies (USD and the EUR) and the pound sterling. For the case of the UK for certain fuels, such as coal and petroleum products, which are typically quoted in USD, this requires a forecast of the exchange rate to convert the USD forecast into GBP.

Ventyx performs fuel price forecasts in real terms for the currency in which the fuel commodity is typically quoted. Since the Ventyx forecast use elements of market data, such as the forward curve where they are available, and these are nominal-market-based prices, these must be converted into real USD using a base USD forecast of inflation.

[26] Included in the graph are the Ventyx reference case forecasts as well as publicly available and privately available independent forecasts. The numbered items 1-8 are privately available independent forecasts which cannot be named, but are made available for comparisons sake.

It is also of note that since the fuel price forecasts are in real GBP, then the economic despatch power price will be in real GBP terms too. Likewise, the appropriate discount rate will be a real rate.

4.2 Plant entry and exit

Market Entry

Planned Resource Additions

In the GBEM, demand and energy requirements are projected to increase during the forecast period, and significant investment in new resources will be needed.

The fossil fuel projects that are currently under construction are all gas-fired. In the last year we have seen a number of project announcements, both gas-fired and coal-fired. However, Ventyx believes it is unlikely that the GBEM market will see new coal plants being built in Great Britain before CCS technology is tested and commercially available as, in addition to uncertainties around cost, technology and subsidy levels, there is strong public opposition to coal plants on environmental grounds. E.ON's Kingsnorth project is on hold, awaiting clarification on the position on CCS and amongst significant public opposition, even though it has received Section 36 approval. On the other hand, with the acquisition of British Energy by EDF, it is more likely that the aging British nuclear plants will be replaced, though it is not thought that the first of these will be operational before 2017, at the earliest.

The project announcements suggest that the GBEM might be able to diversify the resources in the longer term by building new nuclear and coal with carbon storage; though in the short to medium term the capacity gap will be largely filled by gas-fired generation increasing Great Britain's reliance on natural gas.

This study assumes that new generating capacity will enter the marketplace in different phases. In the first phase, all capacity that is currently under construction is assumed to be completed and brought on line. See Table 4-7 for a list of these plants.

Table 4-7: Spring 2009 Reference Case Generation Under Construction in the GBEM

Unit Name	Region	Installation Date	Unit Type	Maximum Capacity	Owner
Marchwood	England	01/09/2009	CCGT	850	ESB International, SSE
Langage	England	01/03/2010	CCGT	885	Centrica
Grain CC 1	England	01/04/2010	CCGT	400	E.On UK
Grain CC 2	England	01/09/2010	CCGT	800	E.On UK
Uskmouth CC	Wales	01/04/2010	CCGT	800	Severn Power
Staythorpe 1	England	01/06/2010	CCGT	425	RWE Npower
Staythorpe 2	England	01/010/2010	CCGT	425	RWE Npower
Staythorpe 3	England	01/01/2011	CCGT	850	RWE Npower
West Burton	England	01/07/2011	CCGT	1,270	EDF Energy

Source: Ventyx

Ventyx has also assumed that the "Pilot CCS Project" (300 MW), the winner of the government CCS competition, will enter the market in 2014.

In developing the Spring 2009 Ventyx GBEM Reference Case study, Ventyx adds four types of resources during the 25-year forecast period in order to meet future needs for new generating capacity. New resources are added in response to forecast electricity demand growth and to offset retirements. New capacity is added when economically viable while maintaining reserve margins that are either in accordance with regional requirements or sufficient to ensure reliability. The four resource types are:

- Gas-fired combined cycle (CC);
- Gas turbine (GT) units;
- New pulverised coal-fired steam turbines fitted with CCS (ST); and,
- Nuclear generators.

The capacity additions are modelled to enter in response to economic conditions such that the level of new entry results in a long-term equilibrium state for new entrants in response to expected profit opportunities. The "balanced" market that results is characterised by constant long-term reserve margins, sustainable price levels, and an annual profit level for new capacity that is sufficient to cover operational as well as fixed and financing costs. In the GBEM, all revenues are assumed to be obtained from the sale of energy.

For the Elexon CBA modelling, Ventyx started with the information of total MW resource expansion per year, and went further to model explicit power stations in the queue for coming online over the next 10 to 15 years. This approach enabled the power flow bus location for the resources to be easily obtained (see Table 4-8). The judgment of which specific plants enter in a given year was balanced between several considerations, such as Section 36 approval, date of interconnection according to National Grid documents, and other factors. All in all, for each year the total MW capacity for all power stations entering matches closely with the expansion MW for generic resources from the Spring 2009 Ventyx GBEM Reference Case (see Table 4-9).

Table 4-8: Thermal Expansion Plan for Elexon Study

	Note		MW cap	Entry Date	Bus	Zone
Drakelow D	T_DRKWPS-9	CCGT	410	2015	DRAK41	E Midlands
Drakelow D	T_DRKWPS-10	CCGT	410	2015	DRAK42	E Midlands
Drakelow D	T_DRKWPS-12	CCGT	410	2015	DRAK41	E Midlands
Pembroke 1 Stage 1		CCGT	800	2016	PEMB40	S Wales
Pembroke 1 Stage 2		CCGT	1200	2016	PEMB40	S Wales
Thor Cogeneration	bus not found	CCGT	1020	2017	THOR40	Northern
Generic Nuke		Nuclear	1650	2017	WYLF40	Mersey
Barking C		CCGT	470	2018	BARP22	LE Dist
Partington	**not in NG table 3.5	CCGT	860	2018	CARR	N / Midlands
Amlwch		CCGT	270	2019	AMLW40	S Wales
Sutton Bridge B		CCGT	1305	2019	SUTB4A	Midlands
Generic Nuke		Nuclear	1650	2020	OLDS12	Midlands
South Holland	**not in NG table 3.5	CCGT	840	2020	NA	E Midlands
Teesport	bus not found	ICGCCT	925	2020	TEEP40	Northern
Little Barford B		CCGT	475	2020	LITB40	Eastern
Abernedd Stage 1		IGCC with CCS	435	2020	BAGB20	S Wales
Thames Haven	**not in NG table 3.5	CCGT	840	2020		Eastern
Hatfield	bus not found	IGCC with CCS	800	2021	THOB40	Yorkshire
Blythe		IGCC with CCS	1600	2021	BLYT40	Northern

Source: Ventyx

Table 4-9: Comparison of Thermal Expansion Plans			
Spr09 Ref Case		Elexon exp plan	
2016	3260	2016	3230
2017	2630	2017	2670
2018	1200	2018	1,330
2019	1560	2019	1575
2020	5250	2020	5165
2021	2400	2021	2400
Source: Ventyx			

Table 4-10 shows the generic units added in the study.

Table 4-10: Autumn 2008 Reference Case Cumulative Generic Unit Additions (MW)				
Year	**Coal**	**CCGT**	**GT**	**Nuke**
2015	0	2,400	0	0
2016	0	5,600	0	0
2017	0	8,400	0	0
2018	0	10,000	1,440	0
2019	0	10,800	2,520	0
2020	0	14,800	2,700	1,650
2021	0	15,600	3,600	1,650
Source: Ventyx				

Capacity Retirements

Planned Nuclear Plant Retirements in the GBEM

The Nuclear Installations Inspectorate (NII) has given permission to Nuclear Decommissioning Authority (NDA) to operate its Oldbury 2 in December 2008 and Oldbury 1 in March 2009 into 2009 and 2010[27]. Ventyx has incorporated this change in the Spring 2009 reference case.

[27] http://www.nda.gov.uk/news/oldbury-power.cfm, http://www.nda.gov.uk/news/oldburyrestart.cfm

Other nuclear plant retirement assumptions have not changed since Autumn 2008. Table 4-11 has a complete list of the announced retirement dates used in the Reference Case simulations.[28]

Last month, NDA also said that it was working on submitting an extension case to the NII to extend the life of Wylfa magnox nuclear power station in Wales for further two years. EdF Energy was granted an extension in December 2007, to the operational lives of Hinkley Point B and Hunterson B power stations until the end of 2016. EdF Energy has also said that it might obtain other extensions. However, these extensions can only delay the nuclear plants' closure to an extent; increasing forced outages are signalling the end of their operational lives. Nearly 66 percent of total installed nuclear capacity is planned to close by 2018.

Table 4-11: Spring 2009 Reference Case Nuclear Plant Closure Date Assumptions

Unit Name	Region	Unit Type	Maximum Capacity	Owner	Retirement Date
Oldbury	England	Magnox	475	BNFL	31/12/2010
Wylfa	England	Magnox	1,081	BNFL	31/12/2010
Hartlepool	England	AGR	1,207	British Energy	31/12/2014
Heysham 1	England	AGR	1,165	British Energy	31/12/2014
Hinkley Point B	England	AGR	1,295	British Energy	31/12/2016
Hunterston B	Scotland	AGR	1,288	British Energy	31/12/2016
Dungeness B	England	AGR	1,089	British Energy	31/12/2018
Heysham 2	England	AGR	1,322	British Energy	31/12/2023
Torness	Scotland	AGR	1,364	British Energy	31/12/2023
Sizewell B	England	AGR	1,220	British Energy	31/12/2035

Source: Ventyx

<u>Impact of the LCPD - Coal and Oil Plant Retirements in the GBEM</u>

In the UK many coal and oil-fired plants will be closed as a consequence of the Large Combustion Plant Directive (LCPD).

[28] An alternative scenario with additional nuclear capacity forms one of the sensitivities to the reference case. All of the sensitivities are contained in Section 6.

In the UK, operators of "existing" large combustion plants (i.e., those first licensed before 1 July 1987) have been given the option of meeting LCPD requirements by participating in the UK NERP.

Beyond 2008, the SO_2 emission limits for plant which "opted-in" under the LCPD are low enough to effectively exclude coal and oil plant which is not equipped with flue gas desulphurisation (FGD) equipment. It also means that for plant to "opt-in" it must install FGD. The alternative way for plant to continue running beyond 2008 is to opt-out of the LCPD—this means that investment in FGD can be avoided, but such stations are limited to running for a maximum of 20,000 hours over the period 2008 to 2015, at the end of which period they must close.[29]

Table 4-12 lists the coal and oil plant opt-out/opt-in decisions according to the LCPD in England, Wales, and Scotland.

Table 4-12: Coal Plants Opt-Out/Opt-In Decisions

Station Name	Operator	Fuel	Installed Capacity (MW)	Capacity Opted In (MW)	Capacity Opted in NERP (MW)	Capacity Opted in ELV (MW)	Capacity Opted Out (MW)
Aberthaw	RWE npower	Coal	1,500	1,500	0	1,500	0
Cockenzie	Scottish Power	Coal	1,200	0	0	0	1,200
Cottam	EDF Energy	Coal	2,000	2,000	0	2,000	0
Didcot A	RWE npower	Coal	2,000	0	0	0	2,000
Drax	Drax Power	Coal	3,960	3,960	3,960	0	0
Eggborough	British Energy	Coal	2,000	2,000	2,000	0	0
Fawley	RWE npower	Oil	1,000	0	0	0	1,000
Ferrybridge C	Scottish and Southern Energy	Coal	2,000	1000	0	1000	1,000
Fiddler's Ferry	Scottish and Southern Energy	Coal	2,000	2,000	0	2,000	0
Ironbridge	E.ON UK	Coal	1,000	0	0	0	1,000
Kilroot	AES	Coal/Oil	520	520	0	520	0
Kingsnorth	E.ON UK	Coal	2,000	0	0	0	2,000
Littlebrook	RWE npower	Oil	2,000	0	0	0	2,000
Longannet	Scottish Power	Coal	2,304	2,304	2,304	0	0

[29] Coal and oil plants that have opted-out have an incentive not to part-load as every hour operated counts as part of 20,000 hours, regardless of output level.

Table 4-12: Coal Plants Opt-Out/Opt-In Decisions							
Station Name	**Operator**	**Fuel**	**Installed Capacity (MW)**	**Capacity Opted In (MW)**	**Capacity Opted in NERP (MW)**	**Capacity Opted in ELV (MW)**	**Capacity Opted Out (MW)**
Peterhead[30]	Scottish and Southern Energy	CCGT	1,320	1,320	1,320	0	0
Ratcliffe	E.ON UK	Coal	2,000	2000	0	2,000	0
Rugeley	International Power	Coal	1,000	1,000	0	1,000	0
Tilbury	RWE npower	Coal	1,520	0	0	0	1,520
Uskmouth	Uskmouth Power	Coal	393	393	0	393	0
West Burton	EDF Energy	Coal	2,000	2,000	0	2,000	0
Source: Ventyx							

In Great Britain, almost all the opted-in coal plants have now FGD fitted. See Section 1 for more details. Ventyx has assumed for the Spring 2009 Reference Case that all opted-in plants have FGD fitted (hence SO_2 removed by 90 percent and VOM increased) starting from the beginning of the study period.

[30] We have Peterhead modelled as 2 ST's (680 and 660 MW) plus 2 GTs (each 115 MW), so the whole station's capacity adds up to 1,570 MW. The actual installed capacity is higher, than listed here, as noted by a Group Member, but the station is restricted by the transmission system; therefore we have only modelled the current maximum rating it has given the transmission constraint.

Previous analysis of the hourly generation data available from the BMRA web site suggested that the operating strategies of the opted-out coal plants differ one to another. When we looked at the hourly generation patterns last Autumn, we have observed plants to either: a) generate baseload (and turn off during weekends); or, b) two-shift, i.e., generate at peak hours and turn off during weekday off-peak periods and weekends. Revisiting the hourly operation data reveals that quite a few of the opted-out coal plants have already used a high percentage of their allowed numbers of hours as shown in Table 4-13. We believe this latest observation suggests that some of these plants will have to close earlier than previously anticipated on top of the risk that the units there are two-shifting will break down and would not be repaired. Ventyx has considered these factors in its LCPD modelling assumptions and modelled a gradual capacity closure between 2011 and 2015. Table 4-13 below shows the total generation for installed opted-out capacity available in the system between 2008 and 2009[31].

Table 4-13[32]: Opted-Out Plants - Number of Hours Generated from January 2008 to (end of) March 2009

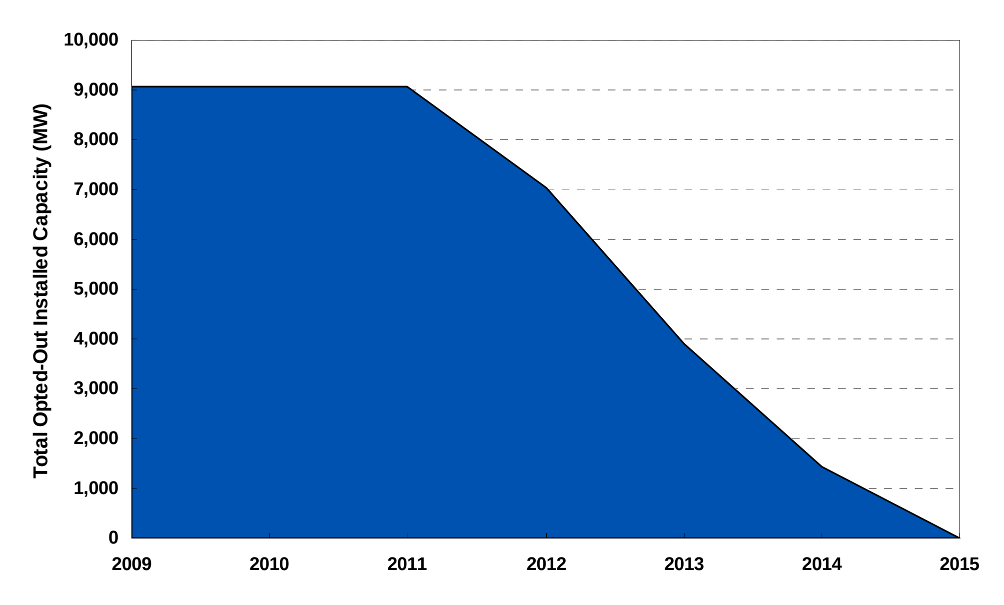
Station Name	Number of Hours Generated
Cockenzie	9372
Didcot A	6389
Ferrybridge C (1 & 2)	4006
Ironbridge	3071
Kingsnorth	6612
Tilbury	8579
Source: BMRA and Ventyx	

[31] We note that we received ex post the actual running hours for the plants from the particular generator owners of each plant. The above modelled Ventyx assumed reference case hours were not too different, and so the above data were representative of the knowledge available for the GBEM Reference Case.

[32] It should be noted that the Opt-Out is on a 'stack' basis. Cockenzie and Tilbury have two stacks. We do not believe this would have significant impact on the modelling however, as the number of hours is applied to the MW capacity and spread over time.

The baseline modelling of the opt-out LCPD plant is from the above from the Ventyx reference case. In addition to the baseline modelling, Ventyx performed additional modelling of these plants with their PROMOD software. The methodology was to add "unit variable cost adders" (i.e., increase their 'bid price' by incremental £/MWh) to the plant until it was running no more than the maximum 20,000hrs.

Figure 4-3: Opted-Out Coal Installed Capacity (MW), 2009 to 2015



Source: Ventyx

<u>**Generic Plant Retirement Assumptions**</u>

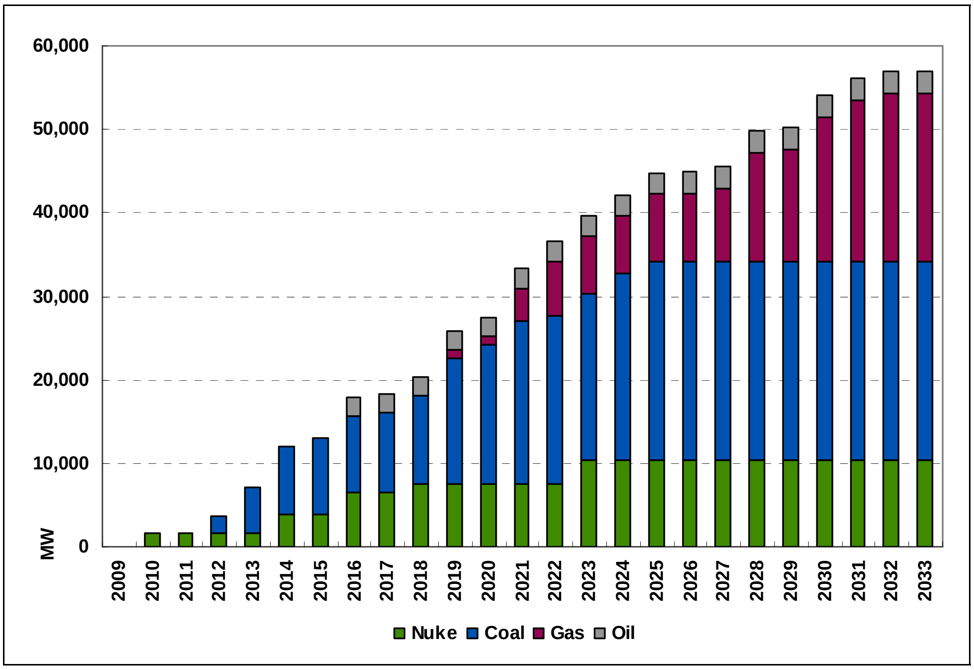
Further out in the Reference Case, existing resources are not only retired based on published retirement schedules, but also depending on the age of the plant. Plants are generally retired based on the following schedule:

- 35-50 years for Gas Turbine stations;
- 50 years for all coal stations with FGD;
- 30-35 years for Combined Cycle stations; and
- No retirement for hydro and wind stations.

Figure 4-4 exhibits the type and volume of capacity retired by year during the study period in the GBEM. Cumulative retirements of existing resources over the 25-year study period are forecasted to be around 56 GW, representing about 72 percent of installed capacity. During the forecast period, 10.3 GW—nearly 90 percent of operating nuclear units throughout the GBEM — are being retired.

There is substantial uncertainty regarding the level of retirements that will actually occur during the study period.

Figure 4-4: GBEM Cumulative Capacity Retirements (MW); 2009-2033



Source: Ventyx

4.3 Demand growth

Demand growth Assumptions

Table 4-14 shows Ventyx's Spring 2009 forecast of annual coincidental peak loads and energy demand for the period 2009-2033.

Ventyx has revised the demand growth to take into account of the impact of the recession. Normally, Ventyx would use the NGC SYS to produce a demand forecast. However, the latest SYS was published in May 2008, so not updated sufficiently recently to capture the impact of the credit crunch.

For the period 2009 to 2013, Ventyx has used the following methodology to forecast the load growth:

- The demand is decomposed in different categories as "industrial" and "services"33 based on historic ratios for energy consumption;
- Regression analysis was used to identify how these two components have responded to changes in GDP in recent history (1998 to 2008)34;
- The relationships obtained in the step above were used to forecast the impact of the forecast GDP changes (as published by the UK treasury in March 2009) on the two elements of demand.
- The 2008 peak and total energy values were then increased using the forecast obtained above. The same growth rate was used for peak and total energy growth from 2009 to 2013.

This two part approach was used as it was expected that the impact of GDP contraction would be rather greater on industrial demand than on commercial or domestic demand – and in fact, this effect was seen in the approach used.

Clearly, this approach depends heavily on historic relationships – most of which were established in an environment of increasing GDP. However, it represents the best approach which Ventyx could identify given the data available at the time of the study.

[33] Eurostat Statistical Books, Gas and Electricity Market Statistics, 2007 Edition, Figure 2.2.

[34] HM Treasury, Pocket Databank, 2 March 2009.

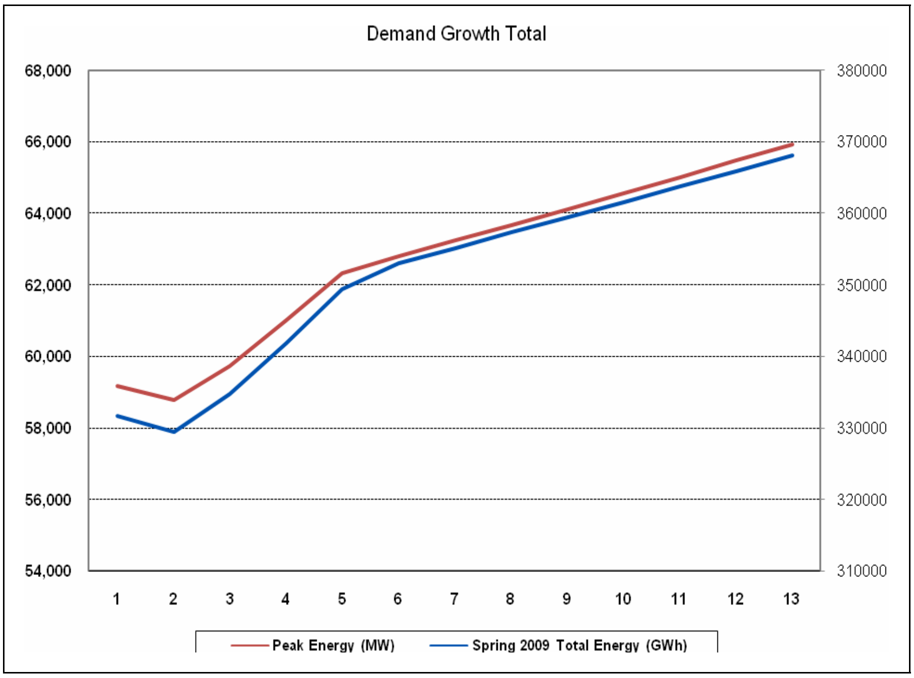
From 2014 onwards, we have assumed that the economy will be back to its long term track and used the load growth assumptions suggested by NGC in their May 2008 Seven Year Statement: a 0.6 percent annual growth rate for the peak load and a 0.7 percent annual growth rate for the total energy.

Table 4-14: Load Forecasts for the GBEM (MW, GWh)

Year	GBEM Peak (MW)	GBEM Energy (GWh)
2011	59,731	334,726
2012	61,008	341,880
2013	62,329	349,285
2014	62,798	353,029
2015	63,235	355,135
2016	63,674	357,253
2017	64,116	359,384
2018	64,563	361,527
2019	65,011	363,683
2020	65,463	365,852
2021	65,918	368,034

Source: Ventyx, UK Treasury, Economist and NGC

Figure 4-5: Demand Growth Total



Source: LE/Ventyx

4.4 Interconnection

Currently, the GBEM is connected to the European transmission electricity system by a link to France. The GB-France interconnector is a 2,000 MW high voltage direct current link with ownership shared between NGC and Réseau de Transport d'Electricité (RTE). Scotland is connected to Northern Ireland by a 400 MW (summer) and 450MW (winter) capacity link.

There are three planned interconnections for the GBEM. The first is a link to the Netherlands, assumed by Ventyx to have a capacity of 1,000 MW and come on line in 2011.

The other two are with the Republic of Ireland: the EirGrid East-West Interconnector project, a 500 MW link, between Ireland and Wales, and Imera East-West Interconnector project with a net transfer capacity of 350 MW. The details on the online assumptions for these interconnectors are shown in Table 4-15.

Table 4-15: Reference Case Interconnector Rates and On Line Date Assumptions			
Interconnector Name	**On Line date**	**Status**	**Link Capacity (MW)**
FR-GB Interconnector	Online	Existing	2,000
Moyle Interconnector	Online	Existing	400
BritNed	01/01/2011	Planned	1,000
EirGrid East-West	01/01/2013	Planned	500
Imera East-West (Phase I)	01/01/2016	Planned	350
Source: Ventyx			

Modelling the All Island (AI) -GBEM interconnector is complex. While one can model the interaction between Great Britain and All-Island as transactions for the Great Britain price forecast, the reverse is not necessarily true. The All-Island energy market is quite small and the commitment/despatch and shadow prices are heavily influenced by the flows from Great Britain. As Great Britain has more efficient and less expensive plants as part of the generation fleet compared to the All-island market, particularly in the early years, this would mean that GBEM units would set the marginal price in the All-Island market. The situation is further complicated by the fundamentally different market models, and as yet unclear detailed interconnector trading rules between the two countries.

After taking account of these factors, and considering the primary focus of this study, Ventyx modelled the interconnector flows on a fixed energy basis with a characteristic hourly shape. Each month has a determined total flow amount (in MWh). The total energy amount for each year is constant, but the monthly total flow variation is preserved. The hourly MWh flow amount was determined by spreading the energy over hours on-peak or off-peak, limited by the MW capacity of the interconnector.

The monthly MWh amounts were derived from historical hourly flows for the existing France-GB and Moyle interconnectors. For the interconnectors not yet in service, hourly forecasted flows from the Ventyx Spring 2009 Reference Case were utilised to determine total flow energy by month. Analysis of the hourly flow patterns revealed the general on-peak / off-peak nature of each interconnector's prevalent flows.

4.5 Existing resources

The sub-section below summarises the plants that are included in Ventyx's database.

Ventyx has used the National Grid Company's (NGC) definition of "grid-connected" capacity for plants that are located in England, Wales, and Scotland. NGC includes all grid connected plant, plus any embedded Large Plant in its definition of generation.

- All plant connected to the 400 kV and 275 kV systems in England and Wales is considered grid connected.
- All plant connected to the 400 kV, 275 kV, and 132 kV systems in Scotland is considered grid connected. This means that some medium sized plant is grid connected in Scotland.

The definition of Large Plant varies by location, based on size:

- England and Wales: > 100MW
- Scottish Power area (SPETL): > 30 MW
- Scottish Hydro area (SHETL): > 10 MW

Plant size is based on the Total Export Capacity (TEC), i.e., it is net of station load.

4.6 Embedded generation

Embedded generation is typically smaller generation such as Combined Heat and Power (CHP) or renewable generation: small hydro, wind, or biomass. The generation from such plant is netted off from the demand forecast made by NGC. On the other hand, NGC's forecasts explicitly include demand served by large embedded generation. As such, any large embedded generation (which includes significant wind generation in Scotland) is explicitly modelled in the GBEM[35] database. For the forecast, LE/Ventyx chose to explicitly model all renewable generation going forward to enable comparisons with set targets, whereas embedded CHP continued to be netted from the forecast demand.

The generation from such plant is netted off from the demand forecast made by NGC. For this study, all the demand and generation metered volume data received from Elexon were at the transmission connected, or non-embedded level. To maintain consistency, only the non-embedded generation resources were modelled. The determination of embedded vs. non-embedded was made from the BM Unit identifier (i.e. T type (transmission connected) versus E type (distribution system connected)) for existing generators, and from the National Grid connection agreement type (i.e. BCA vs. BEGA) for future generators.

As such, embedded generation does not directly impact transmission flows or transmission losses for the GB system within this study.

[35] An installed capacity of approximately 4.9 GW (mainly from biomass, landfill gas, sewage gas, and small hydro) is currently considered as "embedded" in Great Britain, i.e., connected to the distribution grid and netted off from the total GB demand. The GB database takes into account this capacity through the load. On the other hand, this capacity is explicitly considered for the installed capacity (renewable and total) reporting below. Ventyx has modelled future renewable generation additions through the aggregated generation units, assuming this capacity will be connected to the transmission grid.

4.7 Changes to the transmission system

Information on transmission line upgrades was obtained from the National Grid's Seven Year Statement for incorporation into the TLF analysis. All upgrades from 2009 – 2010 were added directly into the transmission data. For 2011 – 2015, selected upgrades were input to address reported congestion in the study results. Many of the upgrades in the National Grid data for this period were local improvements to support new generation interconnections and did not significantly affect regional power transfers. The study results were checked to ensure that all new generation facilities did not encounter significant local congestion limiting their output. Transmission flows for the study were also assessed to ensure there was no excessive congestion impacting study results. Given the study horizon and the uncertainty in transmission planning during the later study years, it was assumed that congestion not anticipated in the current Seven Year Statement would be identified, studied and addressed before causing severe despatch limitations.

4.8 Model validation

As part of the TLF estimation exercise, validation of the PROMOD calculated TLFs versus an alternative is an important part of the process. This was done by comparing the TLF values from PROMOD and Elexon/Siemens. Naturally, as a number of factors were different, the results are not matching exactly, but the closeness of the results suggests a strong confidence in the validity of the model and the comparability of the PROMOD results with the ELEXON TLFs (in other words, how the actual TLFs will be calculated).

4.8.1 Comparison of TLFs from Elexon/Siemens PTL with PROMOD modelled results

In the table below are Ventyx's results for the TLF validation process. The results compare PROMOD results with Siemens/PTI (Elexon's consultants) results. Our understanding is that the Siemens/PTI/Elexon results are the results used for actually calculating the current TLFs; and that the disaggregation by zone and season represents an accurate picture of what zonal/seasonal TLFs would have looked like during the sample period.

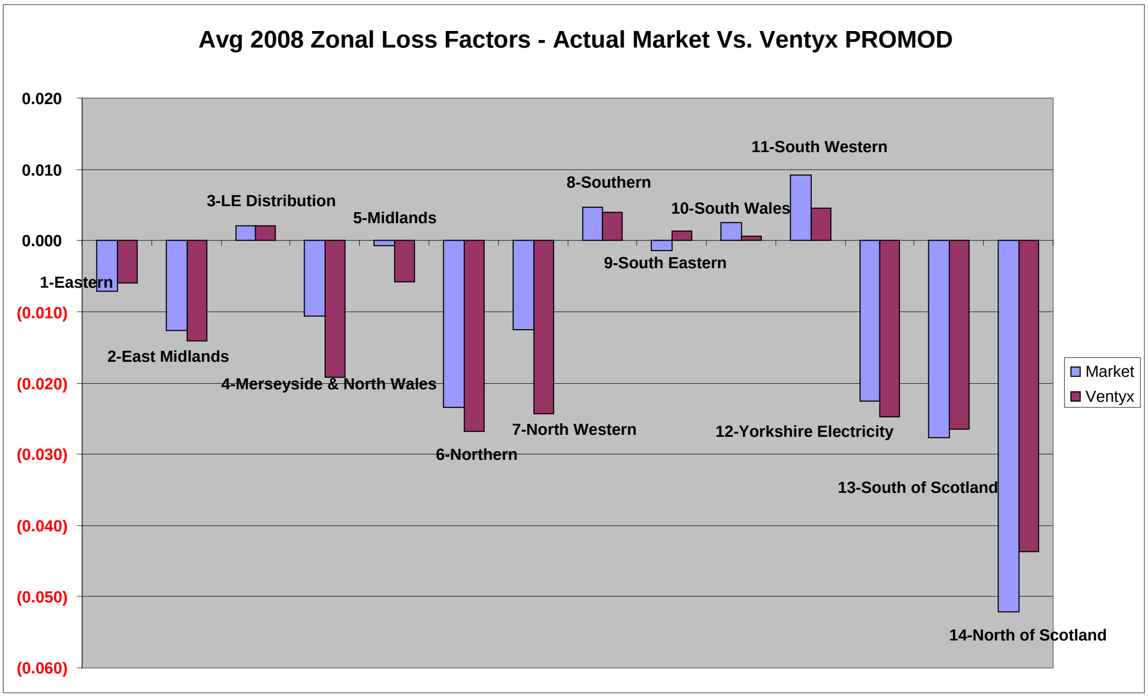
PROMOD calculation of loss factors matches well with the seasonal TLF values provided by Elexon/Siemens. Based on these TLF validation results one can be confident that the data and simulation model are robustly aligned with the market-based results that will be the basis for the actual TLFs that would have been calculated. Table 4-16 presents a summary of the sources of known differences between the TLFs calculated by Elexon/Siemens and those produced by Ventyx.

Table 4-16: PROMOD TLF Validation Results by Zone and Season

Zonal Loss Factors	Spring (market)	Spring (Ventyx)	Summer (market)	Summer (Ventyx)	Autumn (market)	Autumn (Ventyx)	Winter (market)	Winter (Ventyx)	Annual avg (market)	Annual avg (Ventyx)
1-Eastern	(0.006)	(0.008)	(0.008)	(0.007)	(0.008)	(0.005)	(0.007)	(0.004)	(0.007)	(0.006)
2-East Midlands	(0.010)	(0.015)	(0.011)	(0.013)	(0.015)	(0.013)	(0.014)	(0.015)	(0.013)	(0.014)
3-London	0.002	0.001	0.001	(0.000)	0.002	0.002	0.003	0.005	0.002	0.002
4-Merseyside & North Wales	(0.007)	(0.018)	(0.007)	(0.016)	(0.013)	(0.021)	(0.015)	(0.023)	(0.011)	(0.019)
5-Midlands	0.002	(0.006)	0.001	(0.005)	(0.003)	(0.007)	(0.003)	(0.005)	(0.001)	(0.006)
6-Northern	(0.019)	(0.027)	(0.021)	(0.024)	(0.026)	(0.026)	(0.027)	(0.030)	(0.023)	(0.027)
7-North Western	(0.009)	(0.024)	(0.011)	(0.019)	(0.015)	(0.026)	(0.016)	(0.028)	(0.012)	(0.024)
8-Southern	0.004	0.002	0.004	0.002	0.005	0.003	0.005	0.007	0.005	0.004
9-South Eastern	(0.003)	(0.000)	(0.002)	(0.001)	(0.000)	0.001	(0.001)	0.005	(0.001)	0.001
10-South Wales	0.000	0.000	0.004	(0.000)	0.001	(0.001)	0.005	0.003	0.002	0.001
11-South Western	0.009	0.003	0.008	0.003	0.009	0.003	0.011	0.009	0.009	0.005
12-Yorkshire Electricity	(0.018)	(0.026)	(0.020)	(0.022)	(0.026)	(0.024)	(0.026)	(0.027)	(0.023)	(0.025)
13-South of Scotland	(0.015)	(0.019)	(0.028)	(0.026)	(0.037)	(0.024)	(0.031)	(0.037)	(0.028)	(0.027)
14-North of Scotland	(0.039)	(0.043)	(0.047)	(0.046)	(0.065)	(0.038)	(0.057)	(0.049)	(0.052)	(0.044)

Source: LE/Ventyx

Figure 4-6: PROMOD TLF Validation Results by Zone and Season



Source: LE/Ventyx

While the results are quite close, there are some differences, and it is important to understand the reasons for these differences. TLF variances between the PROMOD/Siemens modelling result from three primary differences in modelling technique or assumption:

1) sample hours chosen,
2) generator availability and despatch, and
3) hourly load distribution over buses within each zone.

Addressing the first of these, there is a basic statistical difference between the Siemens TLF values and the PROMOD TLF values, related to the sample size of hours. In calculating TLF values, Siemens used 860 sample settlement periods as proxy for the entire market year. Each of the seasonal TLFs was based on a sample of 215 hours. The PROMOD TLF values were produced from a full 8760 hour simulation, each seasonal value a result of averaging over all hours of the season's months. Using all hours in the PROMOD calculation provides better comparison because differences in actual vs. simulated generator availability from hour to hour could lead to amplified variances with a smaller sample of hours.

To test the validity of this, we calculated the statistical differences between the two samples. In the majority of cases, the differences are not statistically different, and thus we can conclude that mere sampling error may have caused the differences. The results are contained in Table 4-17 and Table 4-18.

Table 4-17: Comparison/Model Validation of TLFs

Zonal Loss Factors	Spring (market)	Spring (Ventyx)	Summer (market)	Summer (Ventyx)	Autumn (market)	Autumn (Ventyx)	Winter (market)	Winter (Ventyx)	Annual avg (market)	Annual avg (Ventyx)
1-Eastern	(0.006)	(0.008)	(0.008)	(0.007)	(0.008)	(0.005)	(0.007)	(0.004)	(0.007)	(0.006)
2-East Midlands	(0.010)	(0.015)	(0.011)	(0.013)	(0.015)	(0.013)	(0.014)	(0.015)	(0.013)	(0.014)
3-London	0.002	0.001	0.001	(0.000)	0.002	0.002	0.003	0.005	0.002	0.002
4-Merseyside & N Wales	(0.007)	(0.018)	(0.007)	(0.016)	(0.013)	(0.021)	(0.015)	(0.023)	(0.011)	(0.019)
5-Midlands	0.002	(0.006)	0.001	(0.005)	(0.003)	(0.007)	(0.003)	(0.005)	(0.001)	(0.006)
6-Northern	(0.019)	(0.027)	(0.021)	(0.024)	(0.026)	(0.026)	(0.027)	(0.030)	(0.023)	(0.027)
7-North Western	(0.009)	(0.024)	(0.011)	(0.019)	(0.015)	(0.026)	(0.016)	(0.028)	(0.012)	(0.024)
8-Southern	0.004	0.002	0.004	0.002	0.005	0.003	0.005	0.007	0.005	0.004
9-South Eastern	(0.003)	(0.000)	(0.002)	(0.001)	(0.000)	0.001	(0.001)	0.005	(0.001)	0.001
10-South Wales	0.000	0.000	0.004	(0.000)	0.001	(0.001)	0.005	0.003	0.002	0.001
11-South Western	0.009	0.003	0.008	0.003	0.009	0.003	0.011	0.009	0.009	0.005
12-Yorkshire Electricity	(0.018)	(0.026)	(0.020)	(0.022)	(0.026)	(0.024)	(0.026)	(0.027)	(0.023)	(0.025)
13-South Scotland	(0.015)	(0.019)	(0.028)	(0.026)	(0.037)	(0.024)	(0.031)	(0.037)	(0.028)	(0.027)
14-North Scotland	(0.039)	(0.043)	(0.047)	(0.046)	(0.065)	(0.038)	(0.057)	(0.049)	(0.052)	(0.044)

Source: LE/Ventyx

Table 4-18: Comparison of Statistical Significance of Difference Between Ventyx and Siemens TLFs										
Zonal Loss Factors	**T-statistic**	**Sign. Difference 95%**	**T-statistic**	**Sign. Difference 95%**	**T-statistic**	**Sign. Difference 95%**	**T-statistic**	**Sign. Difference 95%**	**T-statistic**	**Sign. Difference 95%**
1-Eastern	1.58	not Stat Diff	(0.18)	not Stat Diff	(1.01)	not Stat Diff	(0.83)	not Stat Diff	(0.33)	not Stat Diff
2-East Midlands	2.22	not Stat Diff	1.14	not Stat Diff	(1.01)	not Stat Diff	0.24	not Stat Diff	0.59	not Stat Diff
3-London	0.38	not Stat Diff	0.31	not Stat Diff	(0.14)	not Stat Diff	(0.35)	not Stat Diff	0.00	not Stat Diff
4-Merseyside & North Wales	2.56	Stat Diff	1.80	not Stat Diff	1.69	not Stat Diff	1.71	not Stat Diff	1.65	not Stat Diff
5-Midlands	4.35	Stat Diff	1.74	not Stat Diff	2.14	not Stat Diff	1.12	not Stat Diff	1.93	not Stat Diff
6-Northern	1.72	not Stat Diff	0.36	not Stat Diff	(0.01)	not Stat Diff	0.47	not Stat Diff	0.52	not Stat Diff
7-North Western	1.79	not Stat Diff	0.95	not Stat Diff	2.13	not Stat Diff	2.12	not Stat Diff	1.26	not Stat Diff
8-Southern	0.53	not Stat Diff	0.30	not Stat Diff	0.38	not Stat Diff	(0.32)	not Stat Diff	0.13	not Stat Diff
9-South Eastern	(0.68)	not Stat Diff	(0.29)	not Stat Diff	(0.28)	not Stat Diff	(0.82)	not Stat Diff	(0.46)	not Stat Diff
10-South Wales	(0.02)	not Stat Diff	0.77	not Stat Diff	0.29	not Stat Diff	0.31	not Stat Diff	0.34	not Stat Diff
11-South Western	1.63	not Stat Diff	0.82	not Stat Diff	1.18	not Stat Diff	0.29	not Stat Diff	0.76	not Stat Diff
12-Yorkshire Electricity	1.66	not Stat Diff	0.41	not Stat Diff	(0.55)	not Stat Diff	0.25	not Stat Diff	0.40	not Stat Diff
13-South of Scotland	0.58	not Stat Diff	(0.25)	not Stat Diff	(1.18)	not Stat Diff	0.31	not Stat Diff	(0.08)	not Stat Diff
14-North of Scotland	0.13	not Stat Diff	(0.04)	not Stat Diff	(0.80)	not Stat Diff	(0.27)	not Stat Diff	(0.27)	not Stat Diff

Source: LE/Ventyx

Secondly, another potential source of the variation in the TLFs estimated the variation in generating unit availability and despatch as the most significant driver of differences. The Siemens TLF values were produced using generation MW levels from historical metered volumes. For these sample settlement hours, these MW injections match perfectly with the market. PROMOD IV is a simulation of the market, where generator availability and despatch are a result of the multiple assumptions for cost and operating constraints. Each generating unit has forced outage periods produced by random Monte Carlo method, based on an input forced outage rate and average downtime length. Each generator's maintenance periods are also simulated, resulting from PROMOD's algorithm to schedule these planned outage periods to best minimize the loss of load probability. The PROMOD IV simulation produces realistic forced outage and maintenance periods for 2008, but these do not and are not expected to match historical data.

Finally, PROMOD is using hourly load data from the metered volume data aggregated for each zone that aligns exactly with historical market values. The zonal load in each hour is further distributed over all load buses within the zone according to a fixed distribution ratio for each season that is calculated from the sample hours provided for the bus-level metered volume data. Using a fixed seasonal load distribution within each zone leads to some variance for specific hours but allows PROMOD to model all study hours to produce robust results on total loss volumes.

In addition to the main areas discussed above, as we were not party to the details of Siemens' modelling techniques, there may also be unknown differences in powerflow modelling techniques such as AC vs DC solution, source and sink points for marginal loss analysis, contingency modelling, or other detailed factors that could be a source of small differences in the loss factor calculations.

5 Results reference scenario

This section presents the results of the modelling for the reference scenario. The results are primarily savings between the base and the change cases within the scenario. The results of the TLF modelling show that the P229 proposal is predicted to have significant net benefits. The largest benefits are predicted to come from emissions reductions.

5.1 Overview of results: reference scenario

Table 5-1 shows the levels and differences for base and change case results[36] for major variables from the PROMOD modelling.

Table 5-1: Overview of production costs and impacts on losses

	Reference Base	Reference Change	Change - Base	Change - Base	Reference Base	Reference Change	Change - Base	Change - Base
	Production Cost (£billion)	Production Cost (£billion)	Difference change-base (£b)	% Diff	Transmission Losses (TWh)	Transmission Losses (TWh)	Difference change-base (TWh)	% Diff
2011	6.97	6.96	-0.008	-0.12%	3.82	3.57	-0.246	-6.43%
2012	7.11	7.10	-0.008	-0.11%	3.73	3.42	-0.314	-8.41%
2013	7.38	7.37	-0.006	-0.08%	3.68	3.48	-0.205	-5.57%
2014	7.69	7.68	-0.004	-0.05%	3.63	3.42	-0.204	-5.62%
2015	8.38	8.37	-0.005	-0.06%	3.40	3.22	-0.183	-5.38%
2016	8.65	8.64	-0.005	-0.06%	3.50	3.37	-0.128	-3.65%
2017	8.98	8.98	-0.004	-0.05%	3.78	3.64	-0.146	-3.86%
2018	9.23	9.22	-0.009	-0.09%	3.84	3.61	-0.224	-5.83%
2019	9.70	9.69	-0.010	-0.11%	4.01	3.75	-0.263	-6.54%
2020	9.87	9.86	-0.011	-0.11%	4.13	3.85	-0.282	-6.82%

Source: LE/Ventyx

[36] The results are on a rolling 'full year' basis, i.e., 2011 is the full year starting in April according to the BSC calendar.

5.2 Cost-Benefit analysis

Table 5-2 below shows the total cost benefits from the introduction of P229 for the reference case scenario. The primary benefits are from the production cost savings, which are the result of the net reduction in losses and redespatch costs (including CO_2 cost savings, as this is priced into the production cost, while SOx and NOx, not subject to a cap and trade system are not priced in). The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 5-2: CBA - Reference Scenario without NOx and SOx (£ millions)

Year	Production Cost Savings (million £)	Implementation Costs (million £)	Ongoing Costs (million £)	Annual CBA (million £)	Annual Discounted CBA (million £)
2011	6.87	-3.85	-0.16	2.87	2.74
2012	7.09	0	-0.16	6.94	6.35
2013	6.4	0	-0.16	6.25	5.47
2014	5	0	-0.16	4.84	4.06
2015	3.72	0	-0.16	3.56	2.86
2016	4.82	0	-0.16	4.66	3.58
2017	3.63	0	-0.16	3.47	2.55
2018	8.98	0	-0.16	8.82	6.19
2019	8.49	0	-0.16	8.34	5.6
2020	10.63	0	-0.16	10.47	6.73
Totals					**46.12**
Discounted Demand Side-Benefits					**1.74**
Total (including Discounted Demand-Side Benefits)					**47.86**

The total net benefit from the CBA for P229 under the reference case is £47.86 million. The figures also include potential demand side benefits and but exclude benefits from the reduction of NOx and SOx emissions.

Table 5-3 below, shows the total cost benefits from the introduction of P229 for the reference case scenario, including benefits from the reduction of NOx and SOx emissions. The primary benefits are the emissions savings from NOx and SOx. The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 5-3: CBA - Reference Scenario with NOx and SOx (£ millions)							
Year	**NOx Costs (million £)**	**SOx Costs (million £)**	**Production Cost Savings (million £)**	**Implementation Costs (million £)**	**Ongoing Costs (million £)**	**Annual CBA (million £)**	**Annual Discounted CBA (million £)**
2011	4.48	10.64	6.87	-3.85	-0.16	17.98	17.20
2012	19.16	37.71	7.09	0	-0.16	63.81	58.41
2013	10.83	17.47	6.40	0	-0.16	34.55	30.26
2014	9.50	19.16	5.00	0	-0.16	33.49	28.07
2015	12.34	26.20	3.72	0	-0.16	42.10	33.75
2016	8.19	15.89	4.82	0	-0.16	28.75	22.05
2017	9.06	13.42	3.63	0	-0.16	25.95	19.05
2018	7.35	15.54	8.98	0	-0.16	31.72	22.27
2019	7.99	17.50	8.49	0	-0.16	33.83	22.73
2020	8.89	13.90	10.63	0	-0.16	33.27	21.38
Totals							**275.16**
Discounted Demand Side-Benefits							**1.74**
Total (including Discounted Demand-Side Benefits)							**276.90**
Source: LE/Ventyx							

5.2.1 CBA scenarios – alternative WACC

In relation to the reference case, two alternative WACC scenarios have been considered. These are based on the high (5.2%) and low (3.5%) estimates discussed previously.

Table 5-4 presents the impact of the changing the discount rate on the CBA results without considering the accrued benefits from a reduction in NOx and SOx. Overall, the change in the final CBA figure is relatively small. At the lower discount rate, the total CBA value is approximately 5.5% (£2.64m) higher, while under the higher WACC scenario, the figure is 4.2% (£2.03m) lower.

Table 5-4: CBA - Reference Scenario with high and low WACC estimates – without NOx and SOx (£ millions)

		Annual Discounted CBA (million £)	
Year	**Annual CBA (million £)**	**Low WACC (3.5%)**	**High WACC (5.2%)**
2011	2.87	2.77	2.72
2012	6.94	6.47	6.26
2013	6.25	5.62	5.35
2014	4.84	4.21	3.94
2015	3.56	2.99	2.75
2016	4.66	3.78	3.42
2017	3.47	2.72	2.42
2018	8.82	6.67	5.83
2019	8.34	6.08	5.23
2020	10.47	7.38	6.24
Totals		48.68	44.15
Discounted Demand Side-Benefits		1.82	**1.68**
Total (including Discounted Demand-Side Benefits)		50.50	**45.83**
Source: LE/Ventyx			

Once one includes the additional benefits forecast to accrue from the reduction in NOx and SOx , the relative impacts are broadly similar. Under the lower WACC scenario, the discounted benefits are forecast to be approximately 4.7% (£13.1m) higher, while under the higher discount rate scenario the value is expected to be 3.7% (£10.2m) lower. These results are presented in Table 5-5.

Table 5-5: CBA - Reference Scenario with high and low WACC estimates – with NOx and SOx (£ millions)			
		Annual Discounted CBA (million £)	
Year	**Annual CBA (million £)**	**Low WACC (3.5%)**	**High WACC (5.2%)**
2011	17.98	17.36	17.07
2012	63.81	59.50	57.54
2013	34.55	31.11	29.58
2014	33.49	29.12	27.23
2015	42.10	35.34	32.50
2016	28.75	23.30	21.07
2017	25.95	20.31	18.06
2018	31.72	23.97	20.96
2019	33.83	24.69	21.23
2020	33.27	23.44	19.83
Totals		288.14	265.07
Discounted Demand Side-Benefits		1.82	**1.68**
Total (including Discounted Demand-Side Benefits)		289.96	**266.75**
Source: LE/Ventyx			

Overall, the results of these alternative WACC scenarios indicate that the CBA results are largely insensitive to reasonable changes in the discount rate. Therefore, further scenarios shall present results based on the reference discount rate (4.42%) only.

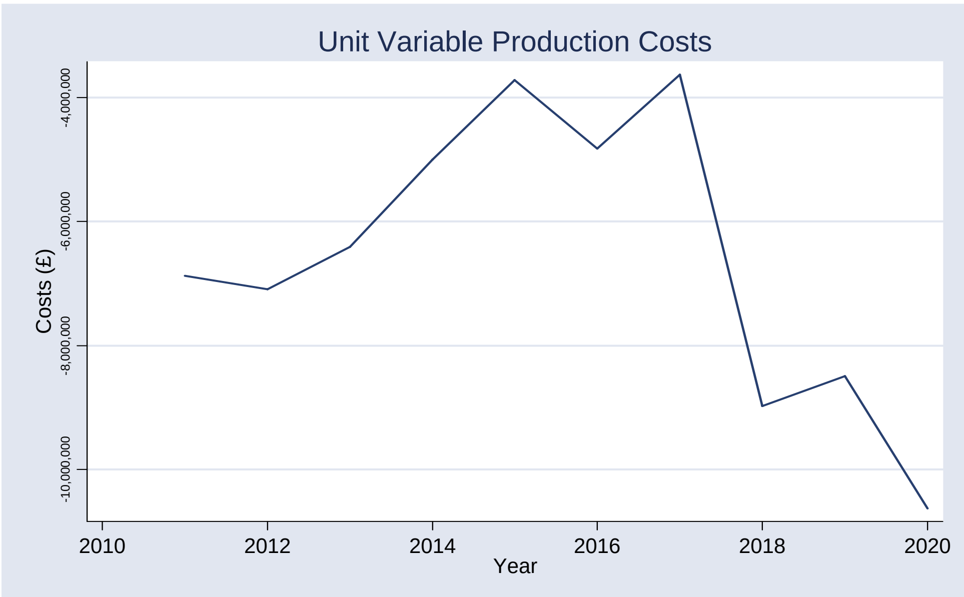
5.2.2 Despatch costs

The primary benefits of P229 derive from lower overall generation costs:

General Total System Generation = Losses + Demand[37] + Net Import/Export

Figure 5-1 shows the difference between the base case (BAU) and the change case for the reference scenario (change case results minus base case results for the reference scenario). The figure displays the differences in total production costs from the modelled differences due to the introduction of seasonal and zonal TLFs. The savings are the net lowering of total generation costs, including savings from losses reductions. The pattern of production cost savings is flat and then falls (graph rising) in years 2013 to 2017, and then savings increase (graph falls) to more than £10m per year by the end of the study period. This is mainly due to the schedule of entry and exit, and the fact that TLFs are calculated on a year-ahead basis. Therefore, significant deviations of entry and exit from the previous year would tend to reduce the savings from the introduction of zonal and seasonal TLFs in any one year.

Figure 5-1: Unit Variable Production Costs



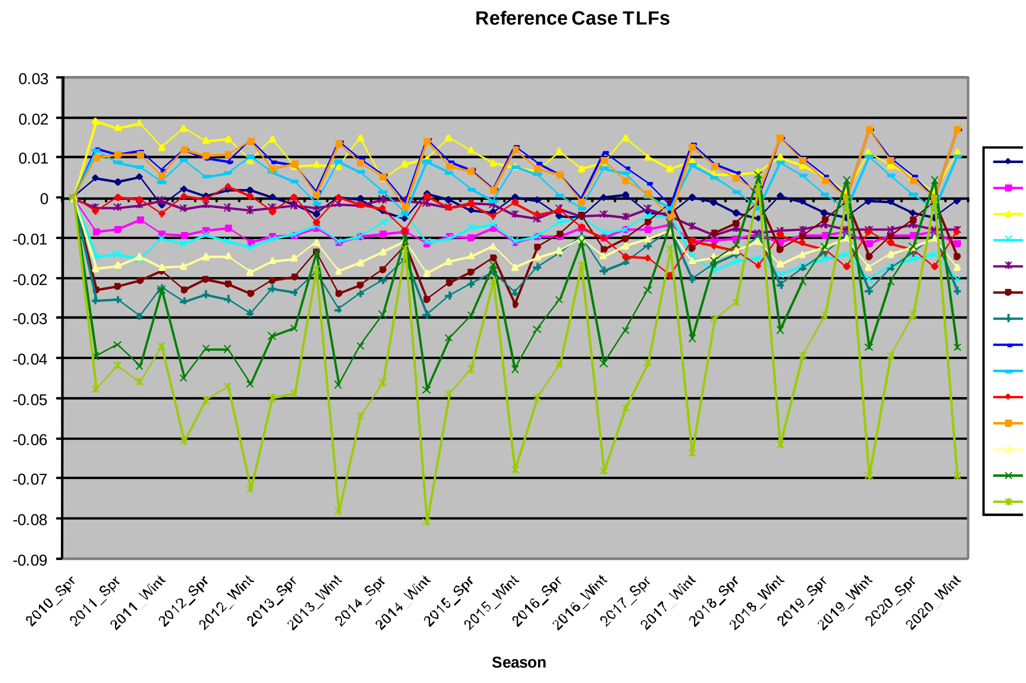
Source: LE/Ventyx

[37] That is to say, demand connected to the transmission system, as some distribution level demand will be served by embedded generation. Pumped storage energy and pumping must be included too.

5.3 Evolved TLFs

The evolved zonal seasonal TLFs as per the reference scenario modelling are presented in Figure 5-2. As expected, Scotland (bottom two zones (North and South Scotland) denoted by the green lines) has the largest negative TLFs, indicating a marginal injection of power in these zones increases marginal power line losses. These are also more seasonally sensitive, as expected, with the winter period being the period where the marginal impact of losses from generation flows from north to south being the greatest (largest negative). Likewise, London (Zone C, yellow line) is the largest positive indicating an injection of power into this zone tends to decrease losses.

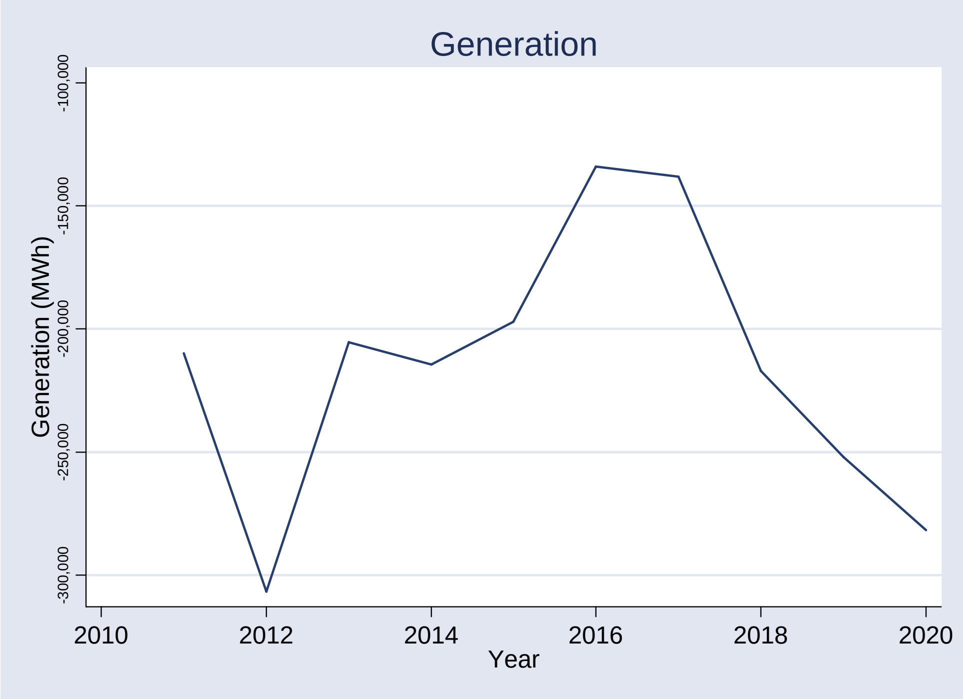
Figure 5-2: Evolved Seasonal Zonal TLFs



Source: LE/Ventyx

5.4 Generation

Figure 5-3: Generation



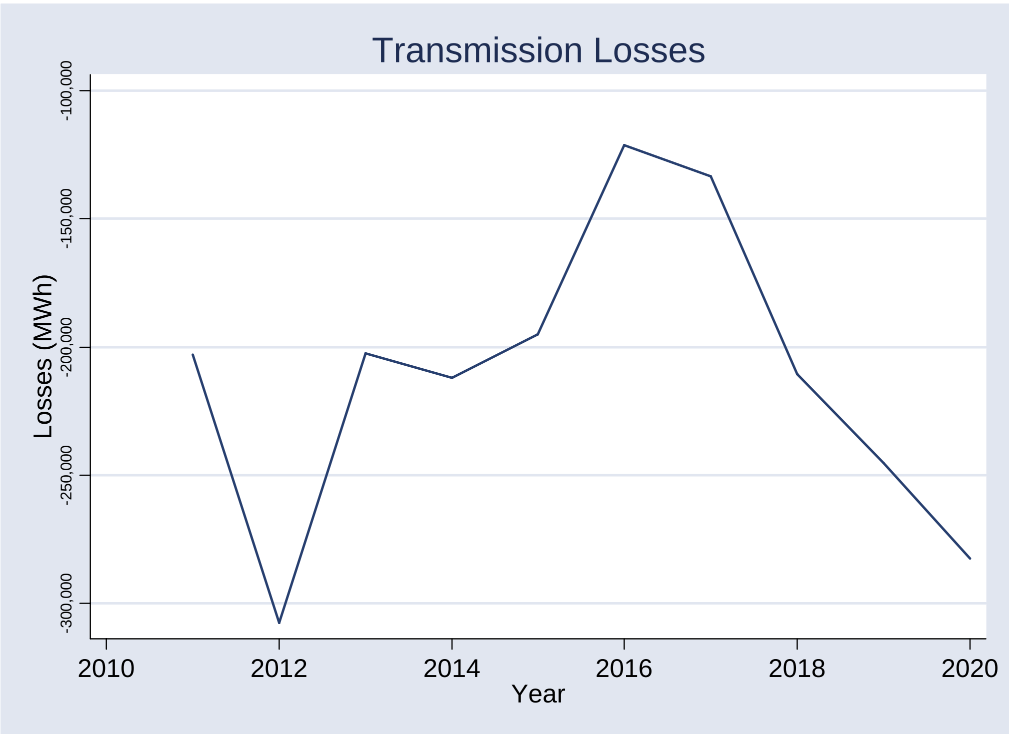
Source: LE/Ventyx

Figure 5-3 presents the impact on generation from the introduction of P229 as modelled by the differences in generation between change minus the base case for the reference scenario. The pattern of generation shows larger benefits (savings in generation) in 2012, and then these reduce, especially in 2015-2017. This largely follows the pattern of production costs. Again, this is consistent with the idea that significant plant entry and exit in those years causes a greater mismatch between the year-ahead estimated TLFs and the actual TLFs that occur during real despatch.

5.5 Losses

The savings in transmission system losses (change case minus base case) from the modelled introduction of P229 for the reference scenario are presented in Figure 5-4. The results show that loss savings per annum are significant in MWh terms, as they reach over 300GWh in some years. The pattern of loss savings largely mimics the pattern of production cost savings, showing that production cost savings are being driven by loss reductions. The lower savings in losses in the middle years around 2015-2017 is again, for the reasons stated previously, that there is entry and exit and other factors that create a larger difference between the year-ahead estimated TLFs and the "actual optimal" TLFs that result during the year.

Figure 5-4: Transmission Losses



Source: LE/Ventyx

5.6 Wholesale prices

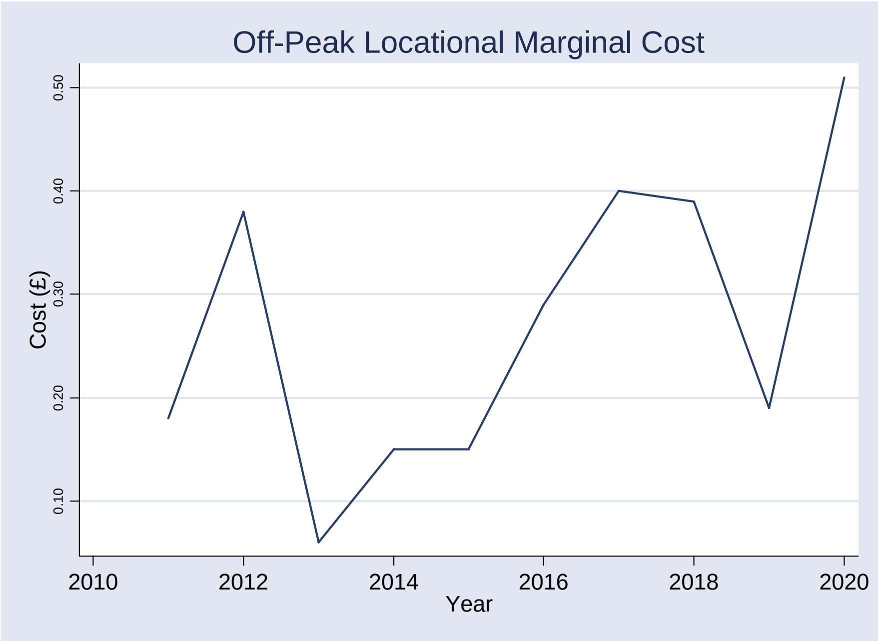
To show the pattern of wholesale price changes, we consider the average annual wholesale price changes predicted by the model between base and change cases for the reference scenario. We present the results for off-peak (Figure 5-5) and peak (Figure 5-6) price periods, peak being 0800-2000 for Dec to March, 0600-2000 for June to Sept, and 0700-2000 for April, May, and Oct.

In general, since we assume competitive despatch and competitive pricing, the prices used in this analysis are the locational marginal costs from the despatch (LMPs), and are the load weighted-average of the hourly simultaneous optimisation of despatch and transmission.

Figure 5-5 shows the difference between the competitive LMPs in the change case minus the base case for the reference scenario. In general, the LMPs are higher under the change case, with the implementation of P229. This is intuitive because the pure despatch cost, ignoring transmission losses, should be optimal with respect to cost minimising without transmission losses. Therefore, optimising over both despatch and losses, while minimising cost on the whole, should raise the pure unit cost of despatch (LMPs). The impact is small; about 20 – 40p.

The results for off-peak periods show a rather modest change in prices. The differences go from about 20p in 2011 to almost 40p, and then fall to near zero in 2013; by 2020 they rise to just over 50p.

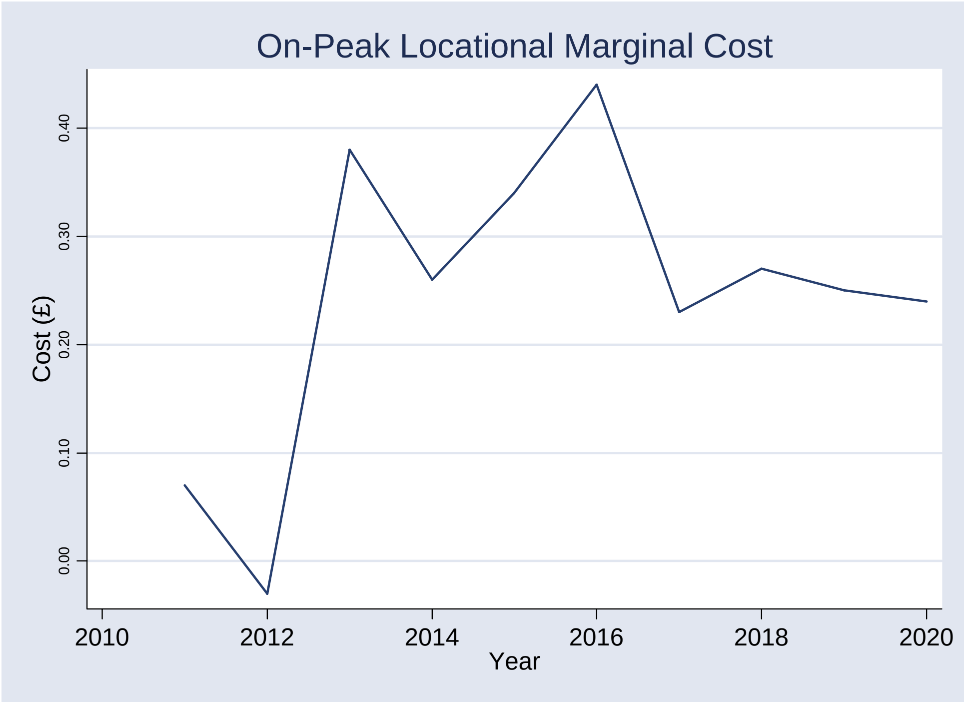
Figure 5-5: Off-Peak Locational Marginal Cost



Source: LE/Ventyx

Figure 5-6 presents the differentials between the change case and the base case for LMPs for the reference case (change case less base case). The intuition is the same for why one observes that the competitive LMPs are higher for the change case. The on-peak prices are marginally closer between the scenarios, although this might be due to less possibility to redespatch during peak. Nevertheless the differences are quite small.

Figure 5-6: On-Peak Locational Marginal Cost



Source: LE/Ventyx

It should be noted that the net effect on prices to consumers[38] should ultimately include the net impact from changes in the competitive wholesale prices plus changes in the BSC prices which reflect the lower losses. It might also be noted that wholesale prices might be less than perfectly competitive, but there is no reason to expect that the introduction of P229 would change mark-ups or bidding behaviour that was a result of less than perfectly competitive market behaviour, as market power is primarily related to market structural variables such as the RSI (see London Economics (2007), study for the EU Commission[39]).

[38] Our terms of reference were specifically not to look at the impacts on final consumers.

[39] http://ec.europa.eu/competition/sectors/energy/inquiry/index.html

5.7 Distributional impacts in CBA from P229[40]

The introduction of zonal-seasonal loss charging will lead to financial transfers among generators and suppliers. To assess the potential size of these transfers at the zonal level, estimates have been calculated based on the results of the system modelling for the single year 2011 (full year starting in April) and the relevant average load weighted price of electricity (by scenario) in this period.

The approach adopted for this scenario estimates the expected zonal transfers arising from the adoption of P229. Therefore, for the reference case it assesses the market value of the distributional impacts of introducing P229 relative to maintaining the current system. The same approach is adopted for all scenarios whereby the estimated impacts are relative to the base case for each scenario. This approach ensures that the value of the impacts for each scenario is attributable only to the introduction of P229.

Table 5-6 presents the distributional results for the reference scenario. On the demand side (retail suppliers) side, we estimate that suppliers connected in Scotland may receive significant benefits of approximately £18 million in 2011. To the extent that supply is a competitive industry, these would be passed on to consumers. Overall the analysis of the demand-side effect indicates that there is likely to be potential for suppliers in the North[41] of Great Britain to reduce prices, while suppliers in the South will likely face pressure to increase prices. On the generation side, the analysis indicates that there would similarly be significant transfers as a result of the introduction of zonal-seasonal loss charging. Generators in Scotland and the North of England are estimated to lose approximately £31 million, with the rest of generators would gain by a similar amount.

[40] We note that the amount of 'text' and analysis applied to the distributional analysis should not be construed as to conceive a 'lower weight' in the decision making process than the efficiency analysis.

[41] For all of our distributional analysis in this scenario and the scenarios that follow, "North" is taken to be the zones: Northern Scotland, Southern Scotland, Northern, North West, Yorkshire; "South" is everywhere else.

Table 5-6: Estimate of the distributional impacts and potential transfers

Zone	Demand (TWh)	Supplier TLM	Transfers (Supply) (£m)	Generation (TWh)	Generator TLM	Transfers Generator (£m)	Net Transfers (£m)
North Scotland	6	0.982	4.73	2	0.969	-1.65	3.08
South Scotland	20	0.987	12.96	34	0.974	-18.12	-5.16
North West	22	0.994	9.34	18	0.981	-5.01	4.33
Northern	16	0.996	5.29	8	0.983	-1.47	3.82
Yorkshire	22	0.999	4.92	49	0.986	-4.47	0.45
Merseyside	13	1.000	2.11	16	0.987	-0.55	1.56
East Midlands	24	1.003	1.23	61	0.990	4.89	6.12
Midlands	26	1.006	-1.52	8	0.993	1.46	-0.06
South Wales	11	1.006	-0.85	19	0.993	3.99	3.14
Eastern	30	1.009	-5.13	12	0.996	3.67	-1.46
South East	18	1.012	-5.13	17	0.999	7.21	2.08
South West	16	1.012	-4.80	15	0.999	6.76	1.97
Southern	33	1.013	-10.75	7	1.000	3.15	-7.60
London	29	1.015	-12.41	0	1.002	0.13	-12.28
Source: LE/Ventyx							

In addition to the financial transfers via the TLFs, we also estimated the change in generation by zone.[42] As expected some zones in the North would expect to see substantially less generation and some zones in the South substantially more.

[42] The change in generation between the default base case and the default change case. This change is calculated per calendar year and is the same for all subsequent scenarios.

Table 5-7: Change in Generation by Zone, Reference Scenario (GWh)

	Year									
Zone	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Eastern	435	1,003	471	732	592	426	549	115	-225	21
East Midlands	-699	-1,347	-1,571	-1,584	-1,200	-879	-296	-408	-305	294
London	105	158	227	166	204	172	167	171	193	206
Merseyside	-547	-677	-543	-64	-331	-376	-183	-1,533	-1,476	-1,637
Midlands	25	-9	-23	27	30	19	-84	-427	-443	-404
Northern	-21	-27	-7	0	0	-82	-396	-388	-539	-919
North West	0	0	0	0	0	0	0	0	0	0
Southern	1,690	2,333	2,018	1,767	1,881	1,663	1,739	2,053	2,491	2,757
South East	354	1,086	649	505	518	328	407	433	522	841
South Wales	476	805	394	203	179	62	-681	-476	-898	-1,672
South West	1,356	2,761	2,067	1,675	1,890	1,541	1,306	2,086	2,486	2,266
Yorkshire	-2,429	-2,781	-3,007	-2,293	-2,234	-1,959	-1,236	-1,803	-1,614	-1,896
South Scotland	-937	-3,549	-788	-1,274	-1,622	-980	-1,353	8	-373	-82
North Scotland	-61	-67	-96	-67	-93	-76	-88	-60	-87	-57

Source: LE analysis of Ventyx Data

In conclusion to the reference scenario distributional analysis, it is clear that there are likely to be significant financial impacts for generation in the North (negative) and generation in the South (positive). For Suppliers it would be the opposite.

5.8 Impacts on the transmission system

5.8.1 Total line flows

The impacts on the transmission system can be studied in a number of ways. Of primary concern would be whether P229 would have any likely impact on congestion and the flows over major lines. To analyse this, we present summary results for the % change in annual flows over the GB system by voltage and year. These results are all comparisons vis-à-vis the base case. On net, P229 is predicted to reduce flows on the system at each voltage level. This is to be more pronounced at higher voltages (see Table 5-8).

Table 5-8: Reference Scenario - Diff (%) Base v. Change total line flows											
Voltage (KV)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
132	-0.66%	-0.31%	-0.18%	-0.16%	-0.29%	-0.16%	-0.07%	-0.36%	-0.10%	-0.14%	-0.22%
275	-2.53%	-0.94%	-1.10%	-0.64%	-0.84%	-0.78%	-0.47%	-2.15%	-1.92%	-2.44%	-2.94%
400	-5.27%	-7.31%	-5.17%	-4.94%	-5.33%	-4.16%	-3.58%	-5.34%	-6.13%	-6.95%	-9.99%

Source: LE/Ventyx

5.8.2 Congestion and LMPs

An alternative way to study the impact on the system is to study congestion. The PROMOD modelling software generates LMPs and divergences in LMPs at any given time is an indication of the value-loss due to congestion on the HV system (the LMP being generated by the marginal cost of the generator within the congested zone which has become functionally separated from the rest of the system). As a measure of this, we present the total hours for each year where congestion occurs in Table 5-9. As before results are vis-à-vis the base case.

Table 5-9: Annual hours with congestion – Reference Scenario				
Year	**Base**	**Change**	**Diff**	**Diff (%)**
2011	261	174	-87	-33.33%
2012	737	641	-96	-13.03%
2013	839	769	-70	-8.34%
2014	1,207	1,084	-123	-10.19%
2015	1,546	1,434	-112	-7.24%
2016	2,257	2,143	-114	-5.05%
2017	296	278	-18	-6.08%
2018	198	179	-19	-9.60%
2019	338	330	-8	-2.37%
2020	387	424	37	9.56%[43]

Source: LE/Ventyx

This table shows the annual number of hours with congestion for both scenarios. The relevant quantity is the difference between the base and the change case. In every year, apart from 2020, the model predicts significant reductions in the number of congested hours on the system. In general the application of transmission loss factors reduces total flows and therefore tends to reduce the congestion hours between the base and change cases. Congestion hours generally increase over time due to increases in load.

In the later study years there are significant changes to congestion patterns due to unit retirements and new entrants. The years 2014-2016 were where particular entry and exit occurred. Less restrictive transmission constraint modelling was used in these later years to reflect the fact that no transmission expansion is modelled beyond the period described in the National Grid GB Seven Year Statement.

[43] We do not believe there is any particular significance to the flip to positive congestion in the last year. In some cases, the forecasted configuration of supply and demand, which is mostly based on historical data which is (at least somewhat) configured and optimised relative to the existing transmission system, may start to put more "strain" on the transmission system. We would expect that typically, over a 10 year time period, some of these issues would be addressed over time by the system operator.

5.9 Impact on demand

The analysis so far has considered that the introduction of zonal/seasonal TLFs will impact generation through the price/cost differentials the new TLF regime will create. While demand patterns across time and GSP Group will be naturally less sensitive to the new TLFs than generation, and also adjust more gradually, it is nonetheless important to consider the impacts of the introduction of zonal-seasonal TLFs on demand. The introduction of the new TLFs will have a positive or negative impact on the prices charged by suppliers (to customers), depending on what zonal region the consumers are located.

To estimate the impacts on demand, we assume a demand elasticity of -0.25%. The assumption is based on a judgmental synthesis of available evidence on demand elasticity discussed in Section 3.4. It might have been considered reasonable to investigate various elasticity estimates, for example, by time, by customer type, etc, but since we did not have data on customer types, such an approach was not relevant. This means that, over a significant period of time, a one percent change in price will give a one percent change in the quantity demanded. The procedure was then as follows:

1. Calculate the effective % change in price in each zone and each season vìs-a-vìs the change in TLMs from the pre and post P229 regime.
2. Calculate the additional wholesale price impact (the redespatch impact assuming competitive prices, i.e., price=marginal cost of despatch) of the new TLFs.
3. Add #1 and #2 from above.
4. Create a % change in price from #3 above and map the % change in price to a % change in quantity demanded across time (season, year), and space (zone).
    a. Map the % change into a total MWh change by season and year.
5. Multiply the zonal/seasonal quantity changes by TLF/2 to estimate the total impact of a change in demand on changes in losses.
6. Multiply the estimated change in losses by the average electricity price/(marginal cost) for the time period from the modelling to give a total £GBP value of the loss savings.

7. Discount to the present the stream of estimated potential loss savings, which gives a final NPV of the demand-side impacts.

A summary of the total discounted loss savings from each of the scenarios (reference case and alternative scenarios) arising from potential demand response effects, are presented in Table 5-10.

Table 5-10: Demand Response Scenarios

Scenario	Loss Savings £m Total Discounted value
Reference	1.74
High gas	3.23
Low Gas	0.36
Fuel Volatility	1.73
Aggressive Offshore Wind	1.82
Alternative Nuclear Development	1.59

Source: LE/Ventyx

The total value from the estimated demand-side impacts from the reference case is about £1.74m. The total values across the five scenarios range from about £0.36m to £3.23 million, both coming from the high and low gas scenarios. In general, high gas prices has two main impact; it makes the value of loss savings higher, but it also makes the TLFs keener, in the sense that the optimisation over losses and despatch becomes 'more willing' to shift despatch to move generation and demand around the system.

In addition, the value of the demand-side response is subject to some qualification, in the sense that this is dependent on elasticities being equal across zones and regions, as well as the likelihood that suppliers facing higher TLFs in fact pass on the changes in TLFs into their prices.

5.10 Environmental impacts emissions

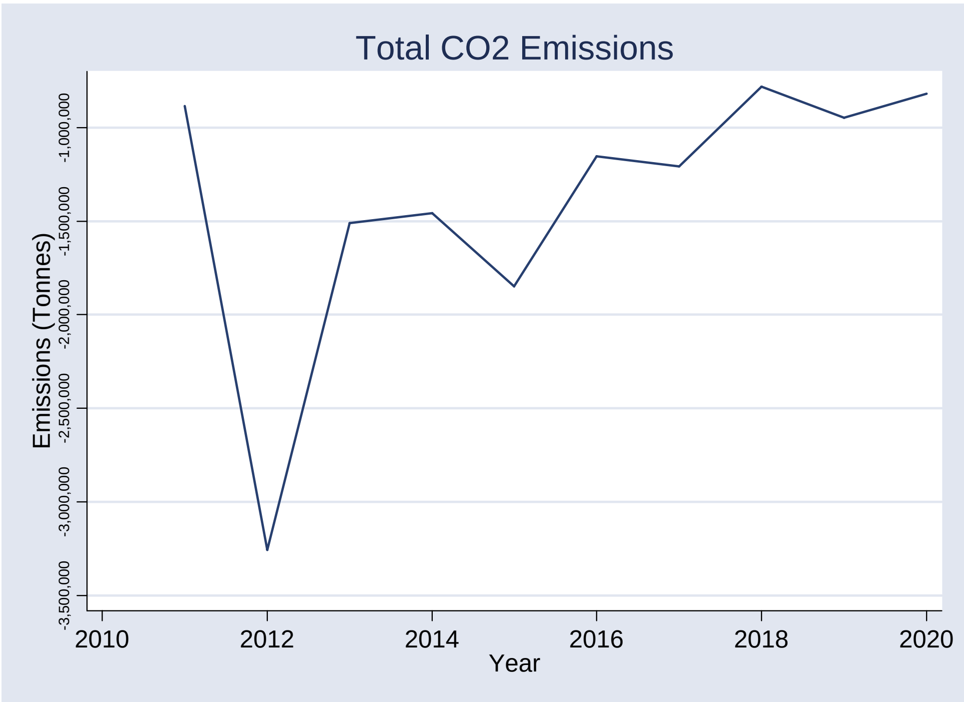
The environmental impacts are assumed to be primarily made up of CO_2 emissions changes, and SOx and NOx emissions changes. There may be other emissions such as mercury, soot, ash, and particulates, but we have not included these.

Fundamentally, it is not obvious *a priori* whether P229 would reduce emissions. Even though the total generation is predicted to reduce in every period, the net impact of P229 could induce fuel switching from low-emissions fuels to high-emissions fuels that would overwhelm the savings on losses. In relation to the reference scenario, the results of the modelling indicate significant emissions savings are expected in every year.

5.10.1 CO_2 emissions

Figure 5-7 presents the total change in tonnes of CO_2 emissions from the modelled reference scenario; the results are again change case minus base case.

Figure 5-7: Total CO_2 Emissions



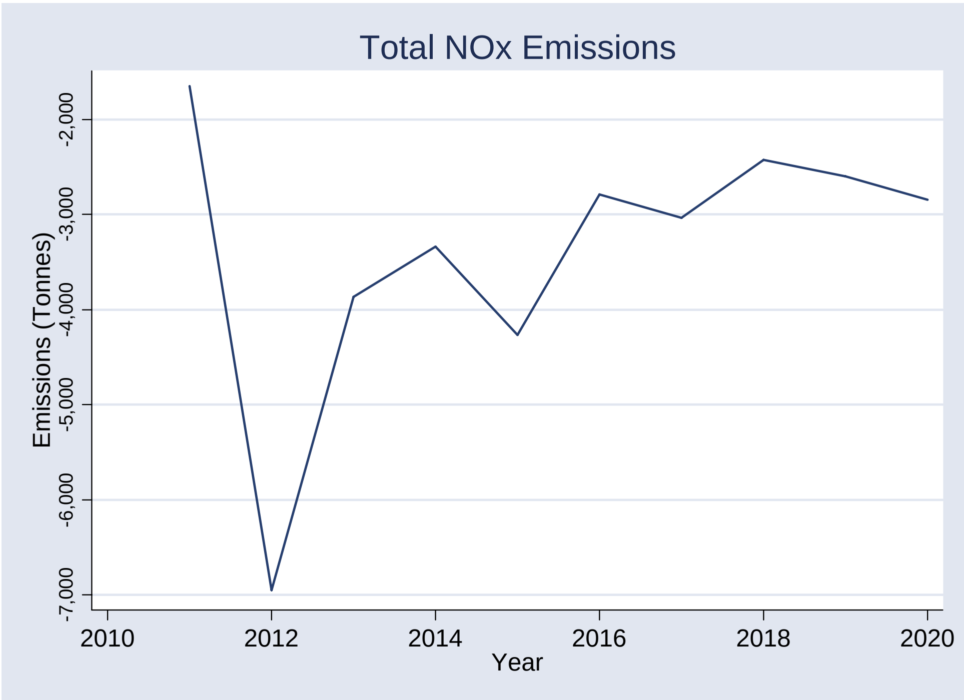
Source: LE/Ventyx

The biggest changes or savings in CO_2 emissions come from the year 2012, with over 3.0m tonnes saved. It is noteworthy that the CO_2 savings values are already in the production cost savings estimates shown above.

5.10.2 SOx and NOx emissions

Emissions for sulphur and nitrogen oxides (SOx and NOx) form some of the most important emissions from the production of electric power, the primary damage from these emissions being acid rain (but also smog and risk to human health). The results presented in Figure 5-8 show that the proposed change is expected to yield reductions in SOx and NOx emissions. The results shown are the change minus the base case for the reference case scenario.

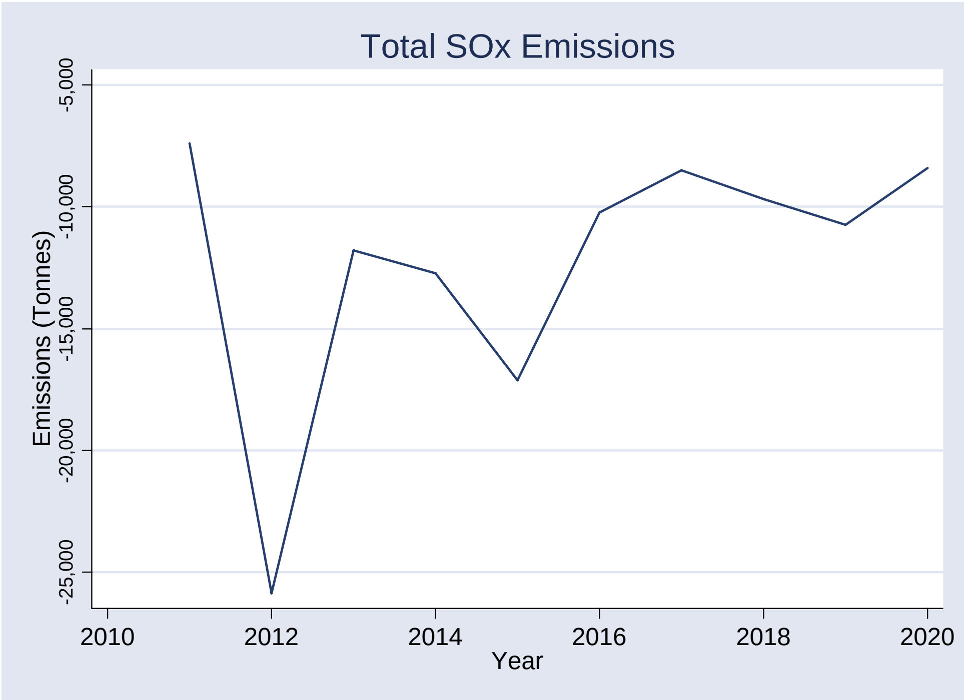
Figure 5-8: Total NOx Emissions



Source: LE/Ventyx

The year 2012 shows almost 7,000 tonnes of NOx emissions savings, and the minimum NOx savings are just under 2,000 tonnes.

Figure 5-9: Total SOx Emissions



Source: LE/Ventyx

SOx emissions savings in the reference case show a largely similar pattern to the NOx savings (see Figure 5-9). The magnitude of the SOx emissions savings is significantly larger than the NOx emissions savings, approximately 2.5 to 3 times the NOx values. Given that SOx and NOx prices/marginal abatement costs are on the order of £1,000-2,000 per tonne, this means that the discounted cost benefit from SOx will be one of the largest drivers of benefits from P229.

6 Sensitivity analysis

This section gives the description and results of the five sensitivity cases. The five sensitivity cases were agreed by Elexon/the Modification Group and in terms of our proposed approach.

6.1 Five sensitivity cases assumptions

Upon contracting and discussions with Elexon, the BSC Modification Group and LE/Ventyx, it was decided that the following five sensitivity cases would be run:

- High Gas Prices
- Low Gas Prices
- Volatile Fuel Prices
- Aggressive Offshore Wind Development
- Alternative Development of Nuclear Assets

It was determined that the following would be the representation of the scenarios:

- High gas—all gas prices were 30% higher than the reference case forecast in all years; other fuels remain the same as in the reference case forecast.

Table 6-1: High gas

	Gas Price Multiplier	Petroleum Fuels Multiplier	Coal Price Multiplier	Uranium and Other Fuels Multiplier
2011	1.3	1	1	1
2012	1.3	1	1	1
2013	1.3	1	1	1
2014	1.3	1	1	1
2015	1.3	1	1	1
2016	1.3	1	1	1
2017	1.3	1	1	1
2018	1.3	1	1	1
2019	1.3	1	1	1
2020	1.3	1	1	1

Source: LE/Ventyx

- Low gas -- all gas prices were 30% lower than the reference case forecast in all years; other fuels remain the same as in the reference case forecast.

Table 6-2: Low gas				
	Gas Price Multiplier	**Petroleum Fuels Multiplier**	**Coal Price Multiplier**	**Uranium and Other Fuels Multiplier**
2011	0.7	1	1	1
2012	0.7	1	1	1
2013	0.7	1	1	1
2014	0.7	1	1	1
2015	0.7	1	1	1
2016	0.7	1	1	1
2017	0.7	1	1	1
2018	0.7	1	1	1
2019	0.7	1	1	1
2020	0.7	1	1	1
Source: LE/Ventyx				

- Volatile fuel prices: the following multipliers were applied to the fuel price forecasts from the reference case for all fuels.

Table 6-3: Fuel price volatility				
	Gas Price Multiplier	**Petroleum Fuels Multiplier**	**Coal Price Multiplier**	**Uranium and Other Fuels Multiplier**
2011	1.3	1.2	1.1	1.05
2012	1	1	1	1
2013	0.7	0.8	0.9	0.95
2014	1.3	1.2	1.1	1.05
2015	1	1	1	1
2016	0.7	0.8	0.9	0.95
2017	1	1	1	1
2018	1.3	1.2	1.1	1.05
2019	0.7	0.8	0.9	0.95
2020	1.3	1.2	1.1	1.05
Source: LE/Ventyx				

- Aggressive offshore wind: the aggressive offshore wind scenario essentially assumes that all the reference case price assumptions hold, but that the forecast for offshore wind is greatly increased. The assumption was that essentially about 1,200MW more of offshore wind would be built[44]. Our view was that with the current climate of lower than expected (vis a vis a year or more ago): demand forecasts, fossil fuel prices, and higher than expected: financing costs, and nuclear capacity, other non-traditional thermal capacity (embedded gen, CHP, etc); that this level of additional offshore wind was sufficient to test the sensitivity of the reference case to the level of offshore wind development. Thus the only real purpose of the development of this scenario was to test whether the conclusions for the reference case would be significantly sensitive to the level of offshore wind development, within a reasonable level of the scenario. We further note that significant uncertainty as to the location of such connections may actually exist, along with the exact starting dates and MW installed capacity, as well as the actual electrical output and profiles of future sites. The table below details the offshore wind capacity under the scenarios.

Table 6-4: Spring 09 Ref Case - Installed Wind Capacity MW

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
GB Off-Shore Wind	404	566	688	1,340	1,690	2,090	2,490	3,010	3,460	3,910	4,360	4,810	5,260	5,760
growth off-shore (MW)		162	122	652	350	400	400	520	450	450	450	450	450	500
growth rate (%)		40%	22%	95%	26%	24%	19%	21%	15%	13%	12%	10%	9%	10%

Source: LE/Ventyx

[44] It should be noted that the goal of this analysis was not to predict per se the total offshore wind including all Gov't targets and including Round 3 of the National Grid Crown Estate study.

Table 6-5: Aggressive Off-shore Wind Sensitivity - Installed Wind Capacity MW														
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
GB Off-Shore Wind	404	614	773	1,621	2,076	2,596	3,116	3,792	4,332	4,837	5,332	5,827	6,322	6,872
growth off-shore (MW)		211	159	848	455	520	520	676	540	505	495	495	495	550
growth rate (%)		52%	26%	110%	28%	25%	20%	22%	14%	12%	10%	9%	8%	9%
Source: LE/Ventyx														

- Alternative nuclear development: this scenario provides a view of P229 in the context of a more aggressive development of nuclear assets in the latter years of the study. In the reference scenario, one new nuclear generator was commissioned in 2017. Within this scenario, five new nuclear generators come online between 2017 and 2020 based on the listed dates in TEC register and other factors such as company ownership and location. The new non-nuclear thermal generators coming online between 2017 and 2021 in the Reference scenario are delayed 2 years to keep the capacity expansion assumption in line with the Reference scenario, with regards to total GW capacity per year required to maintain the target reserve margin. As a result, the estimated values in the period up to 2017 will mirror those of the reference case, with differences emerging following this date. All other data input and modelling assumptions from the Reference Case remain unchanged. Table 6-6 presents the alternative development schedule.[45]

[45] The commission date is based on the TEC register date, with reasonable delay for some generators, and also of a balanced view of build-out by companies (4,950 MW by EDF, 1,200 by RWE consortium, and 1,600 by E.ON consortium).

Table 6-6: Alternative Nuclear Development			
Generator	**Zone**	**Capacity (MW)**	**Commission Date**
Sizewell	A_Eastern	1650	01/11/2017
Hinkley Point C Unit 1	L_South Western	1650	01/01/2018
Hinkley Point C Unit 2	L_South Western	1650	01/11/2018
Oldbury	E_Midlands	1600	01/04/2020
Wylfa	D_Merseyside & North Wales	1200	01/11/2020
Total		**7,750**	
Source: LE/Ventyx			

6.2 Scenario #1: High Gas Prices

6.2.1 Overview of results: high gas prices

Table 6-7 shows the levels and differences for base and change case results[46] for major variables from the PROMOD modelling.

Table 6-7: High Gas Sensitivity

	Reference Base	Reference Change	Change - Base	Change - Base	Reference Base	Reference Change	Change - Base	Change - Base
	Production Cost (Billion Pounds Sterling)	Production Cost (Billion Pounds Sterling)	Diff	% Diff	Transmission Losses (TWh)	Transmission Losses (TWh)	Diff (TWh)	% Diff
2011	7.51	7.50	-0.010	-0.14%	3.81	3.61	-0.204	-5.34%
2012	7.71	7.70	-0.014	-0.18%	3.99	3.77	-0.221	-5.52%
2013	8.04	8.03	-0.009	-0.11%	4.09	3.87	-0.216	-5.28%
2014	8.39	8.38	-0.008	-0.10%	3.97	3.75	-0.212	-5.35%
2015	9.21	9.20	-0.005	-0.05%	3.68	3.50	-0.180	-4.90%
2016	9.56	9.55	-0.007	-0.08%	3.70	3.58	-0.126	-3.39%
2017	9.94	9.93	-0.014	-0.14%	3.95	3.78	-0.170	-4.31%
2018	10.23	10.21	-0.020	-0.19%	4.04	3.80	-0.243	-6.00%
2019	10.82	10.80	-0.024	-0.22%	4.29	3.94	-0.347	-8.09%
2020	11.02	10.98	-0.034	-0.31%	4.38	4.01	-0.374	-8.53%

Source: LE/Ventyx

6.2.2 Cost-Benefit analysis

The Table presented below outlines the total benefits from the introduction of P229 for the high gas price scenario.

The results of our analysis found that the total net loss from the CBA for P229 under the high gas price scenario was -£16.73 million pounds.

[46] The results are on a rolling 'full year' basis, i.e., 2011 is the full year starting in April according to the BSC calendar.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-8: CBA - High Gas Price Scenario with NOx and SOx (£ millions)

Year	NOx Costs	SOx Costs	Production Cost Savings	Imp. Costs	Ongoing Costs	Annual Net-Cost Benefit	Discounted Net-Cost Benefit
2011	-£2.69	-£3.06	£7.87	-£3.85	-£0.16	-£1.89	-£1.81
2012	-£8.11	-£6.89	£13.26	£0	-£0.16	-£1.90	-£1.74
2013	-£6.62	-£6.43	£10.82	£0	-£0.16	-£2.39	-£2.09
2014	-£6.60	-£8.05	£9.00	£0	-£0.16	-£5.82	-£4.87
2015	-£7.46	-£8.47	£5.12	£0	-£0.16	-£10.97	-£8.79
2016	-£2.13	-£5.13	£5.53	£0	-£0.16	-£1.88	-£1.44
2017	-£4.49	-£9.55	£12.16	£0	-£0.16	-£2.04	-£1.49
2018	-£6.04	-£10.52	£18.30	£0	-£0.16	£1.59	£1.11
2019	-£4.90	-£11.46	£20.31	£0	-£0.16	£3.79	£2.55
2020	-£11.04	-£25.56	£34.59	£0	-£0.16	-£2.17	-£1.39
Totals						**-£23.67**	**-£19.97**
Discounted Demand Side-Benefits							**£3.23**
Total (including Discounted Demand-Side Benefits)							**-£16.73**

Source: LE analysis of Ventyx Data

The table presented below shows the total benefits from the introduction of P229 for the high gas price scenario excluding NOx and SOx.

The major benefits are from the production cost savings which are the results of the net reduction in losses and despatch costs. The results show a net benefit of £101 million pounds.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-9: CBA – High Gas Price Scenario without NOx and SOx (£ millions)					
Year	**Production Cost Savings**	**Imp. Costs**	**Ongoing Costs**	**Annual Net-Cost Benefit**	**Discounted Net-Cost Benefit**
2011	£7.87	-£3.85	-£0.16	£3.86	£3.69
2012	£13.26	£0	-£0.16	£13.10	£11.99
2013	£10.82	£0	-£0.16	£10.66	£9.34
2014	£9.00	£0	-£0.16	£8.84	£7.41
2015	£5.12	£0	-£0.16	£4.97	£3.98
2016	£5.53	£0	-£0.16	£5.38	£4.12
2017	£12.16	£0	-£0.16	£12.00	£8.81
2018	£18.30	£0	-£0.16	£18.15	£12.74
2019	£20.31	£0	-£0.16	£20.15	£13.54
2020	£34.59	£0	-£0.16	£34.44	£22.13
Totals				**£131.55**	**£97.77**
Discounted Demand Side-Benefits					**£3.23**
Total (including Discounted Demand-Side Benefits)					**£101.0**
Source: LE analysis of Ventyx Data					

Thus, in the case of high gas prices, the benefits of P229 excluding NOx and SOx are higher than under the reference case. However, as the scenario was modelled as raising gas prices alone (i.e., holding the other fuel price forecasts constant), this scenario is predicted to induce significant fuel switching from gas to coal, which is predicted to substantially increase SOx and NOx emissions, which in turn make the overall net benefits negative.

A noteworthy sensitivity is that the qualitative or overall direction of the total CBA is sensitive to the high gas scenario when NOx and SOx are included. An anecdotal explanation of this is that, as one might expect, the combination of high gas prices and locational signals make production of electricity by coal and more emissions intensive fuel technologies more economical. The combined result is to shift more generation towards coal and oil and away from gas (which is less emissions intensive).

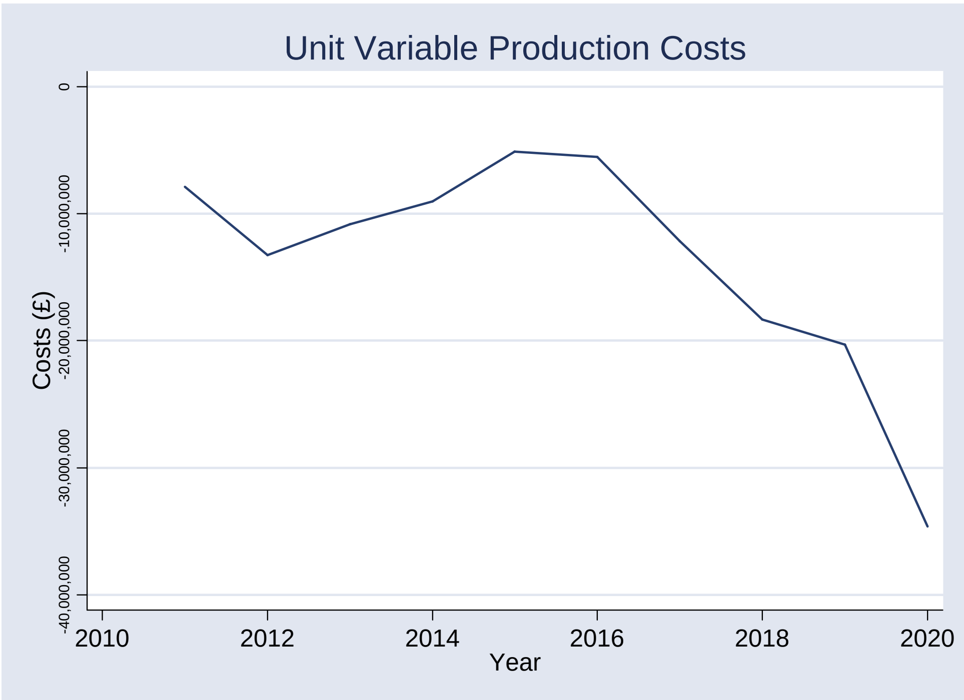
6.2.3 Despatch costs

In the high gas price scenario, the primary benefits of P229 derive from lower overall generation costs, as total system generation equals losses plus demand.

The Figure presented below shows the difference between the base case (BAU) for total generation costs and the change case for the high gas price scenario.

Production costs savings fall moderately (shown by the graph rising) in the period from 2012 to 2016. After 2016, we observe a sharp increase in savings (graph falling) to more than £30 million pounds per year by 2020.

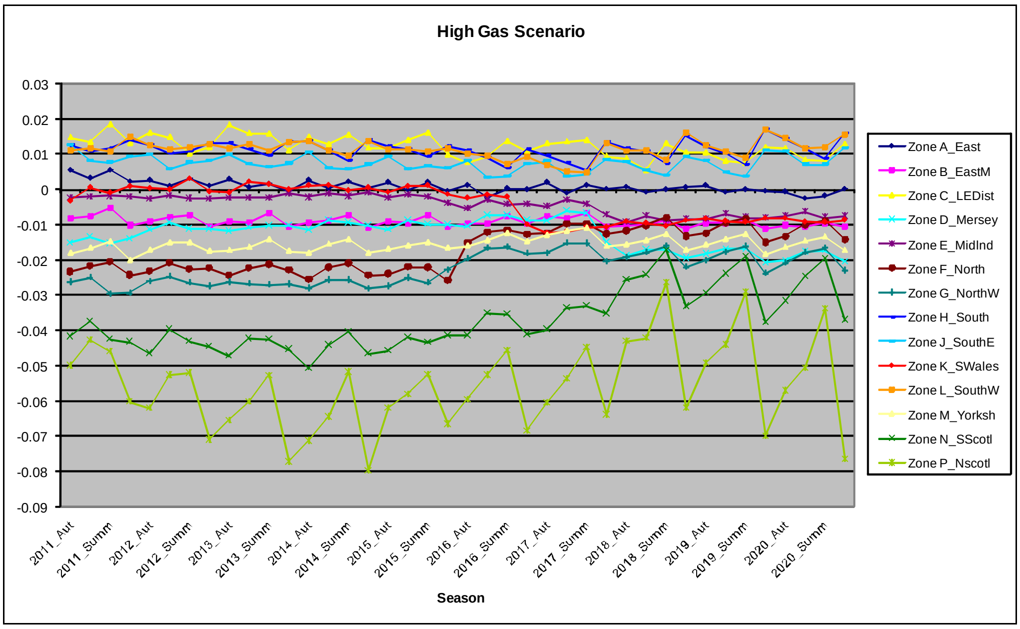
Figure 6-1: Unit Variable Production Costs - High Gas Prices



Source: LE/Ventyx

6.2.4 Evolved TLFs

Figure 6-2: High Gas Scenario



Source: LE/Ventyx

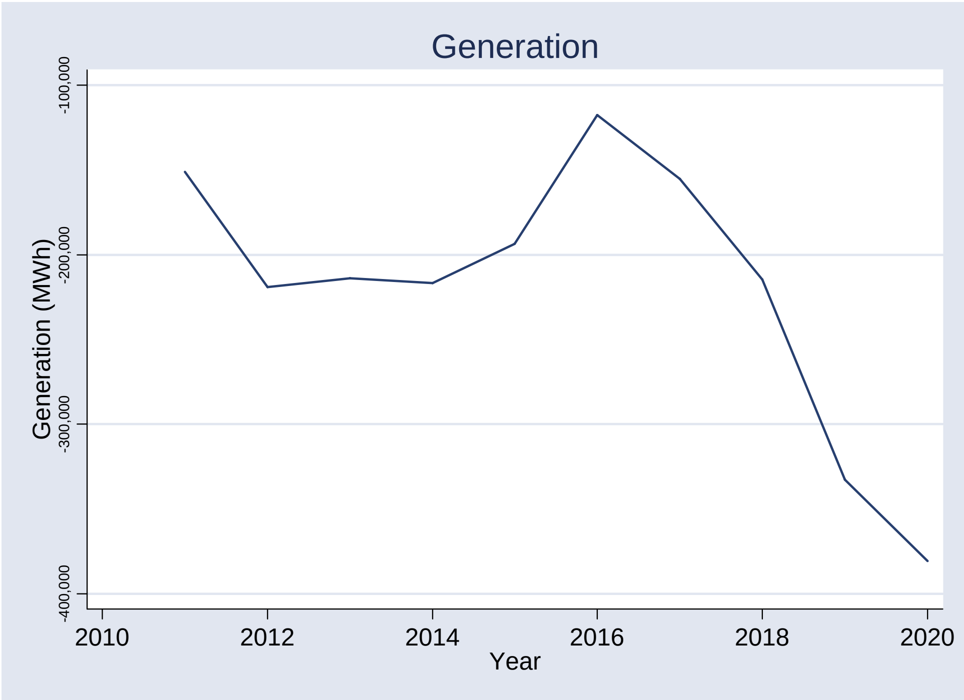
The Figure presented above outlines the evolution of TLFs, by zone, from the years 2011 to 2020 for the high gas price scenario.

In general, the levels for most of the zones remain roughly flat over the modelling horizon with many exhibiting a slight upward trend in the middle years and then falling to their original levels. Most of the volatility within zones can be explained by changes between seasons for a given year.

There is a high volatility observed in a few zones including Zone P and Zone N.

6.2.5 Generation

Figure 6-3: Generation - High Gas Prices



Source: LE/Ventyx

The figure above shows the impact on generation from the introduction of P229 as modelled by the differences between the observed change case minus the base case for the high gas prices scenario.

The generation graph follows an upward trend in the middle years, particularly between 2012 and 2016, indicating smaller benefits as a result of generation. After this point however, the pattern follows a steady decline indicating sustained larger benefits as a result of generation over this period.

This graph correlates with production costs. This may be explained by the plant entry and exit in those years widening the gap between the year-ahead estimated TLFs and the TLFs that arise during real despatch.

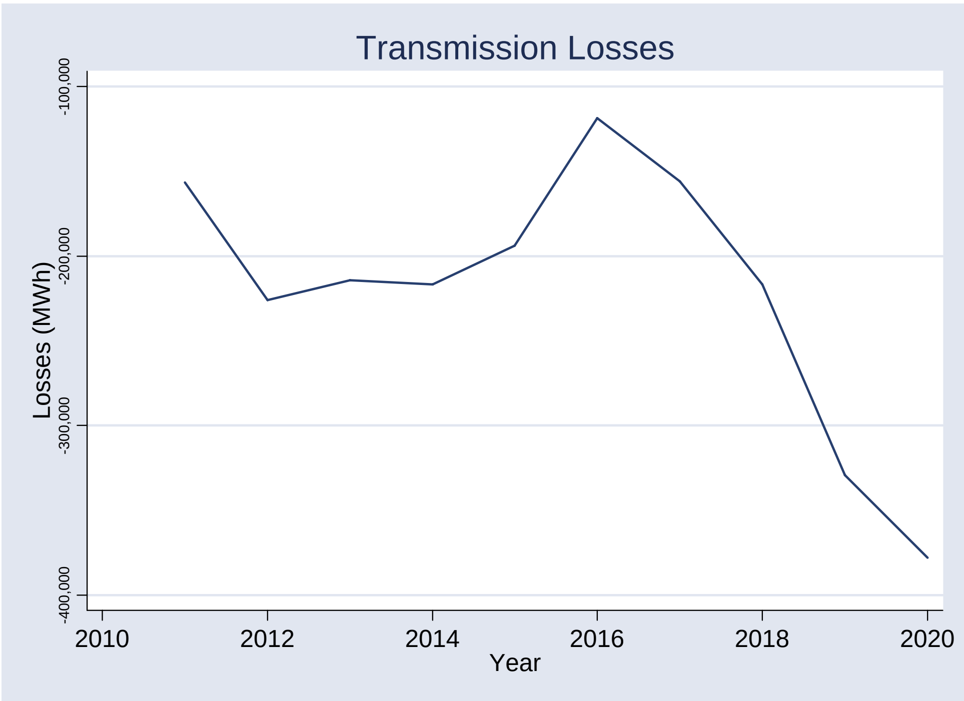
6.2.6 Losses

The Figure presented below charts the (change case minus base case) savings accrued as a result of transmission from the modelled introduction of P229 for the high gas price scenario.

The results show that loss savings per annum are considerable, reaching 400MWh by the end of the modelled horizon. Initially, we observe less loss savings in the middle years, in particular between 2014 and 2016. This trend then reverses and considerable loss savings are achieved in all subsequent years up until the end of the study period.

The pattern of transmission losses largely mimics the pattern of production cost savings, showing that production cost savings are being driven by loss reductions.

Figure 6-4: Transmission Losses - High Gas Prices



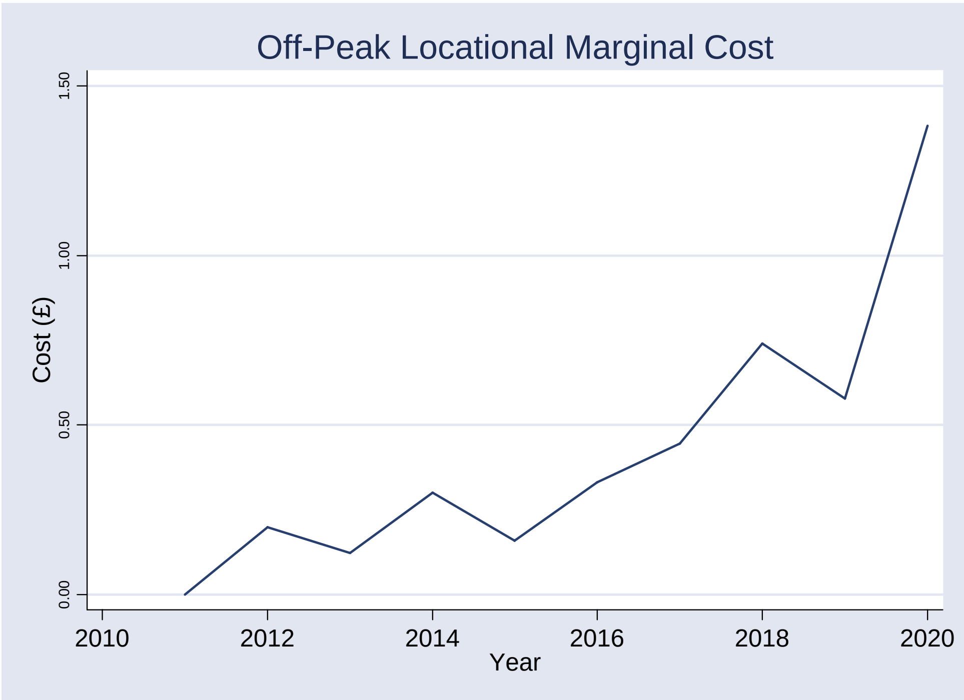
Source: LE/Ventyx

6.2.7 Wholesale prices

To show the pattern of wholesale price changes, we consider the average annual wholesale prices as measured by the locational marginal costs (LMPs) from PROMOD. The prices are the load weighted average LMPs by season.

We present the results for peak and off-peak price periods (peak being set to 0800-2000 for Dec to March, 0600-2000 for June to Sept, and 0700-2000 for April, May, and Oct. 8:00 to 20:00).

Figure 6-5: Off-Peak Locational Marginal Cost - High Gas Price Scenario

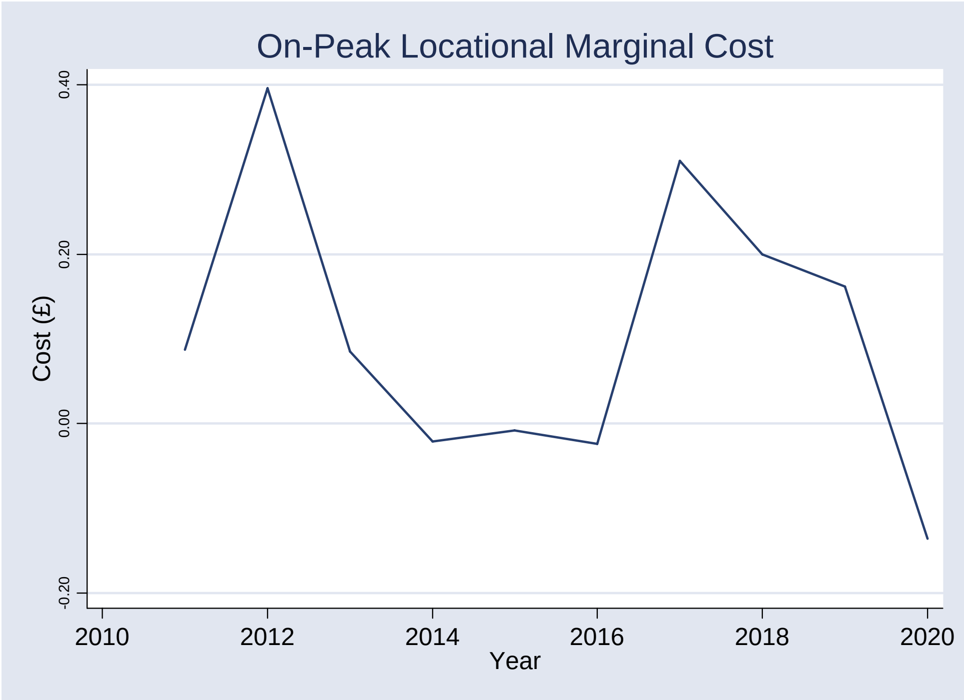


Source: LE/Ventyx

The Figure presented above shows the difference between the competitive off-peak LMPs in the change case minus the base case for the high price scenario. In general, the LMPs are higher under the change case, P229.

The results show a modest but overall consistent increase in off-peak prices over the study period. The differences between scenarios fluctuate from approximately 20p – 25p between 2012 and 2016. The differences then steadily increase from over 50p in 2018 and finally to over £1 by 2020.

Figure 6-6: On-Peak Locational Marginal Cost - High Gas Prices



Source: LE/Ventyx

The Figures presented above display the differentials between the competitive on-peak LMPs in the change case minus the base case for the high price scenario. The intuition is the same that the competitive LMPs are higher for the change case.

The pattern of on-peak price differences moves from 40p in 2012 and then hold at approximately zero between 2014 and 2016. The differences then progress from a high of over 20p in 2017 before falling below zero and finally to approximately -10p over the last few years.

6.2.8 Distributional impacts in CBA from P229

Table 6-10 presents the distribution impacts and transfers, across zones, for the high gas price scenario. The results indicate that there will be potential transfers for generators and suppliers in each of the regions. The magnitude of transfers in each region has been calculated from the 2011 system modelling data.

Table 6-10: Estimate of the distributional impacts and potential transfers – High Gas Price Scenario

Zone	Demand (TWh)	Supplier TLM	Transfers (£m)	Generation (TWh)	Generator TLM	Transfers (£m)	Net Transfers (£m)
North Scotland	6	0.981	6.22	2	0.968	-2.28	3.94
South Scotland	20	0.986	17.23	36	0.973	-25.24	-8.01
North West	22	0.993	11.85	18	0.980	-6.35	5.50
Northern	16	0.996	6.69	8	0.983	-1.84	4.85
Yorkshire	22	0.999	6.06	48	0.986	-5.21	0.85
Merseyside	13	1.000	2.60	16	0.987	-0.60	2.00
East Midlands	24	1.003	1.35	60	0.990	6.70	8.05
Midlands	26	1.006	-2.12	8	0.993	1.94	-0.18
South Wales	11	1.006	-1.22	19	0.993	5.43	4.21
Eastern	30	1.009	-6.86	12	0.996	4.65	-2.21
South East	18	1.012	-6.60	18	0.999	9.44	2.85
South West	16	1.013	-6.55	15	1.000	8.92	2.37
Southern	33	1.013	-14.15	7	1.000	3.99	-10.16
London	29	1.014	-14.50	1	1.001	0.46	-14.04

Source: LE/Ventyx

On the demand side (suppliers), the results estimate that suppliers/consumers in Scotland may receive benefits of approximately £24 million, while consumers in Northern England may receive £25 million.

On the generation side, generators in Scotland and the North of England are estimated to lose approximately £41 million while southern generators are expected to benefit by a similar amount

In addition to the transfer analysis, we present results in the change in generation predicted by zone for this scenario. This is the difference between the base generation level in the high gas scenario and the change generation in the high gas scenario.[47] As before, zones in the North of GB are expected to lose generation while zones in the South are expected to produce more.

Table 6-11: Change in Generation by Zone, High Gas Scenario (GWh)

	Year									
Zone	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
East	337	340	347	289	417	366	376	370	-495	-414
East Midlands	-474	-1,342	-1,085	-1,122	-640	-1,103	178	7	953	785
London	129	201	257	287	298	171	106	101	135	219
Mersey	-549	-640	-645	-625	-485	-517	-572	-972	-984	-733
Midlands	44	40	20	34	87	53	80	-806	-864	-916
North	0	0	-13	0	0	0	-864	-918	-1,038	-2,397
North-West	0	0	0	0	0	0	0	0	0	0
South	1,222	1,458	1,508	1,611	1,627	1,589	1,521	1,998	2,469	2,746
South-East	368	382	288	79	-13	-319	-363	-194	-96	348
South Wales	408	926	780	744	353	965	570	511	-781	-1,056
South-West	925	1,620	1,394	1,537	1,585	1,313	1,418	1,890	2,780	2,905
Yorkshire	-2,257	-2,799	-2,588	-2,476	-2,895	-2,280	-2,094	-2,122	-2,254	-1,882
South Scotland	-264	-337	-386	-499	-447	-307	-394	1	-93	65
North Scotland	-40	-67	-90	-75	-81	-48	-116	-81	-64	-50

Source: LE analysis of Ventyx Data

[47] Importantly, the change in generation for all scenarios measures the difference between change and base generation **within** each scenario. The change in generation, as measured here, **is not** the difference between generation in each scenario and the level of generation in the reference case scenario.

6.2.9 Impacts on the transmission system

Table 6-12: High Gas - (%) Change Annual Line Flows

Voltage (KV)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
132	-0.42%	-0.13%	-0.16%	-0.16%	-0.16%	-0.11%	-0.40%	-0.19%	-0.18%	-0.10%	-0.23%
275	-1.03%	-1.11%	-1.22%	-1.22%	-1.33%	-0.98%	-1.48%	-1.42%	-1.97%	-2.25%	-2.64%
400	-4.74%	-5.30%	-4.97%	-5.05%	-5.18%	-4.07%	-4.48%	-5.71%	-7.58%	-9.06%	-10.75%

Source: LE/Ventyx

The data presented in the above table show the annual percentage differences in total line flows between the base case and the change case for the high gas price scenario. The data outline the percentage changes in total line flows, across time, for three different voltage levels.

In each year and for each voltage type, the model is predicting small but significant reductions in line flows. This is consistent with the aggregate effect of P229, which is to reduce overall line losses.

In addition, the pattern of flow reductions is higher on the higher voltage lines. This is as expected, since typically the higher voltage lines would be the lines transporting power over long distances.

This also confirms the conclusion that P229 is predicted to have little impact on 132kV lines and connected users. (Note: 2011 and 2021 are partial calendar years).

6.2.9.1 Congestion

Table 6-13: Annual hours with congestion - High Gas

Year	Base	Change	Diff	Diff (%)
2011	289	241	-48	-16.61%
2012	782	741	-41	-5.24%
2013	1,007	940	-67	-6.65%
2014	1,217	1,137	-80	-6.57%
2015	1,740	1,584	-156	-8.97%
2016	2,389	2,257	-132	-5.53%
2017	295	272	-23	-7.80%
2018	192	176	-16	-8.33%
2019	326	327	1	0.31%
2020	401	389	-12	-2.99%

Source: LE/Ventyx

The Table presented above outlines the annual number of hours with congestion in the base case and the change case for the years 2011 to 2020 under the high gas price scenario.

Transmission loss factors reduce aggregate flows which we would expect to further tighten the gap between the base and change case scenarios. It might also be noteworthy that generally congestion hours tend to increase over time as a result of increases in load.

In terms of pure hours, both the base and change case follow a similar pattern; rising steadily until 2016 and falling thereafter. The nominal differences between the two scenarios are also larger and increasing up until 2016; after which time they are considerably smaller. Changes observed in congestion in the later stages of the study years may be explained by unit retirements and new entrants.

6.2.10 Impact on demand

The demand side impacts for the high gas price scenario is estimated to be £3.23m, as previously described in the reference scenario demand-side section.

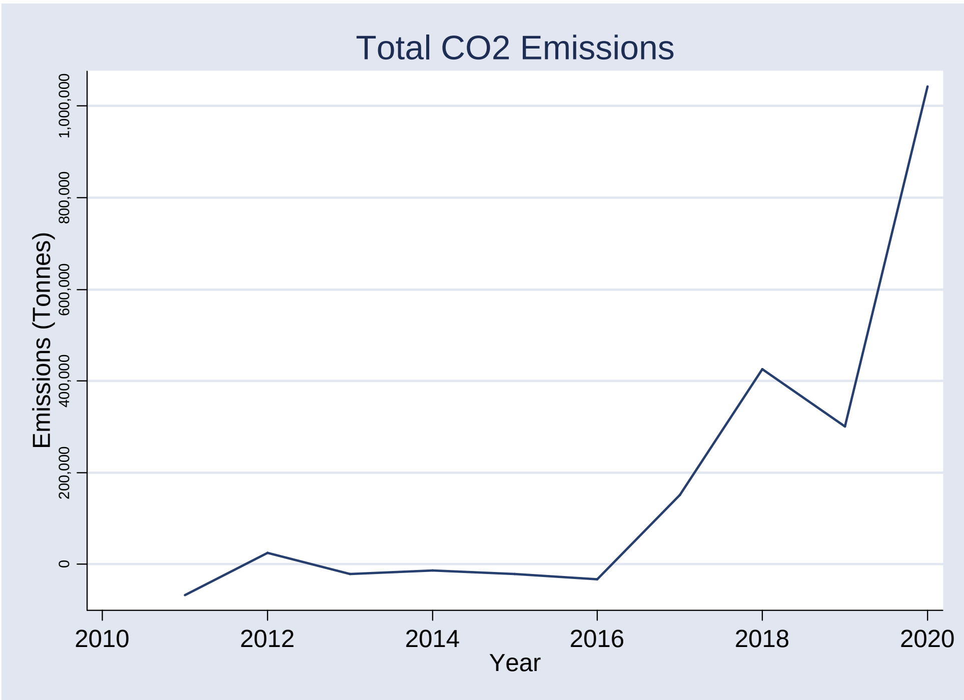
6.2.11 Environmental impacts emissions

The environmental impacts are assumed to be primarily made up of CO2 emissions changes, and SOx and NOx emissions changes. There may be other emissions such as mercury, soot, ash, and particulates, but we have not modelled these.

6.2.11.1 CO2 emissions

The figure below shows the total change in tonnes of CO2 emissions from the modelled high price scenario; the results are again the change case minus the base case.

Figure 6-7: Total CO_2 Emissions - High Gas Prices



Source: LE/Ventyx

Total CO_2 Emissions remain flat between 2012 and 2016 and subsequently progress to just over 400,000 tonnes in 2018 and then over 1,000,000 tonnes by the end of the study period.

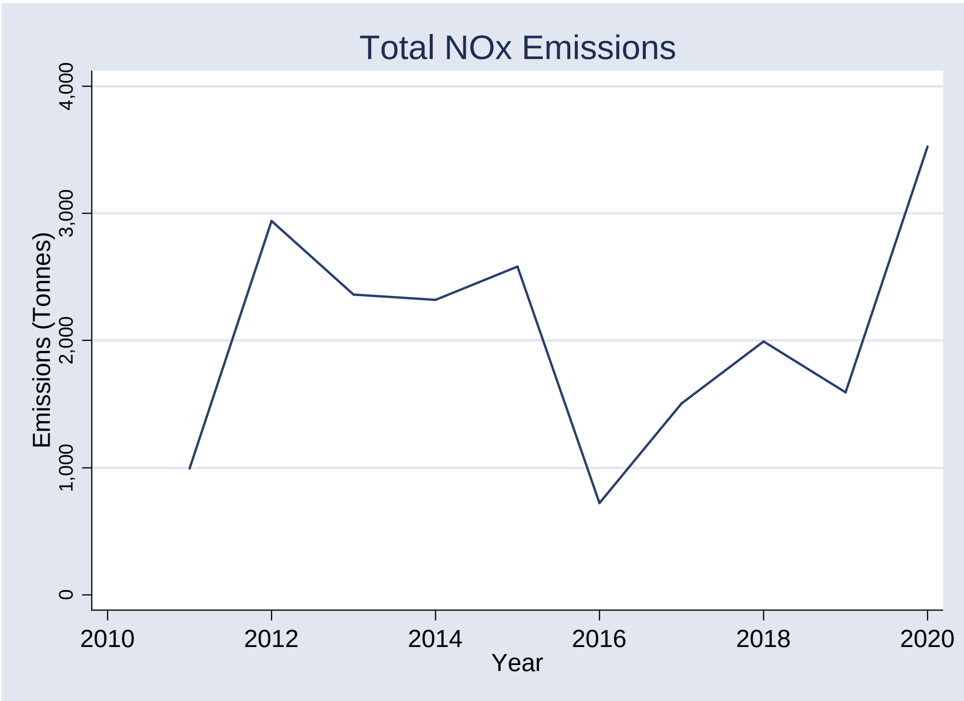
It is noteworthy that the CO_2 emission values are already in the production cost savings estimates shown above.

6.2.12 SOx and NOx emissions

Emissions for sulphur and nitrogen oxides (SOx and NOx) form some of the most important emissions from the production of electric power, the primary damage from these emissions being acid rain.

The results shown are the change case minus the base case for NOx Emissions in tonnes the high gas price scenario.

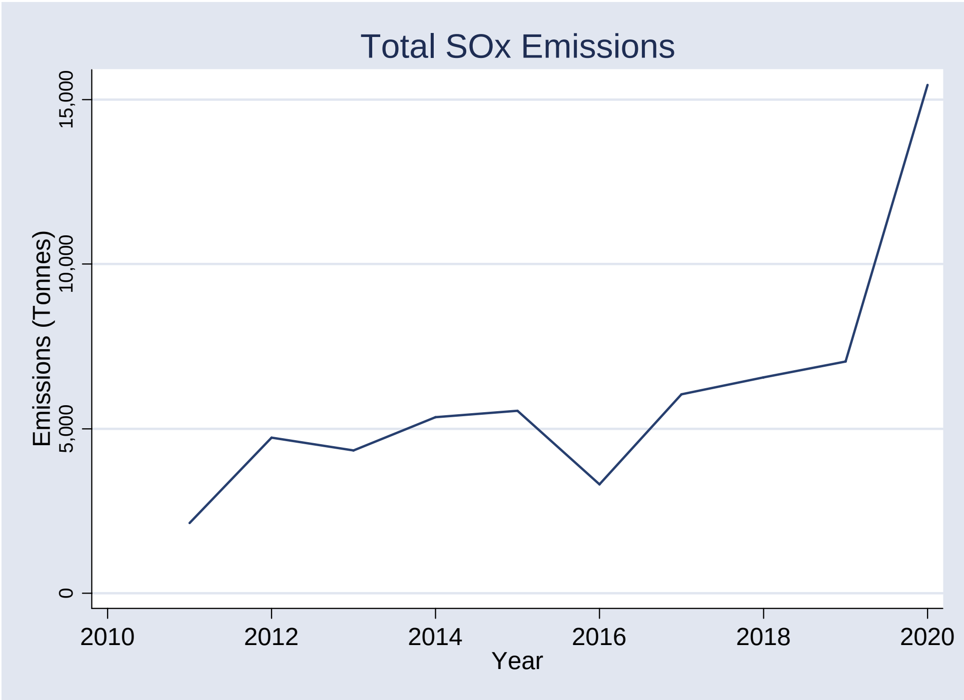
Figure 6-8: Total NOx Emissions - High Gas Prices



Source: LE/Ventyx

Our analysis illustrates that under this scenario, annual NOx emissions increases are predicted to rise to just less than 3,000 tonnes in 2012 and subsequently just less than 1,000 tonnes in 2016. The highest annual amount of emissions increase is in 2020 at over 3,000 tonnes.

Figure 6-9: Total SOx Emissions - High Gas Prices



Source: LE/Ventyx

The results shown are the change minus the base case for SOx Emissions in the high gas price scenario. Emissions increases in SOx remain roughly stable at approximately the 5,000 tonne mark over the period 2012 to 2018. After this point, the additional emissions increase significantly to over 15,000 in 2020.

6.3 Scenario #2 – Low Gas Prices

6.3.1 Overview of results: Low Gas Prices

Table 6-14 shows the levels and differences for base and change case results[48] for major variables from the PROMOD modelling.

Table 6-14: Low Gas Sensitivity

	Reference Base	Reference Change	Change - Base	Change - Base	Reference Base	Reference Change	Change - Base	Change - Base
	Production Cost (Billion Pounds Sterling)	Production Cost (Billion Pounds Sterling)	Diff	% Diff	Transmission Losses (TWh)	Transmission Losses (TWh)	Diff (TWh)	% Diff
2011	6.07	6.06	-0.004	-0.06%	2.94	2.81	-0.127	-4.31%
2012	6.03	6.03	-0.001	-0.02%	2.99	2.93	-0.064	-2.14%
2013	6.24	6.24	0.001	0.01%	3.17	3.08	-0.096	-3.01%
2014	6.51	6.51	-0.001	-0.02%	3.08	2.97	-0.108	-3.50%
2015	7.08	7.08	0.000	0.00%	2.96	2.88	-0.082	-2.78%
2016	7.25	7.25	-0.001	-0.01%	3.12	3.06	-0.058	-1.85%
2017	7.51	7.51	0.001	0.02%	3.32	3.29	-0.033	-0.98%
2018	7.69	7.69	-0.003	-0.04%	3.35	3.27	-0.083	-2.49%
2019	8.02	8.01	-0.002	-0.03%	3.43	3.34	-0.086	-2.50%
2020	8.11	8.11	-0.001	-0.02%	3.55	3.44	-0.110	-3.10%

Source: LE/Ventyx

6.3.2 Cost-Benefit analysis

The Table presented below shows the total cost benefits from the introduction of P229 for the low gas price scenario. Like the previous scenario, the most important benefits are from the emissions savings from NOx and SOx. Our analysis from the CBA found that there was a total net benefit from P229 under the low gas price scenario of £73.55 million pounds.

[48] The results are on a rolling 'full year' basis, i.e., 2011 is the full year starting in April according to the BSC calendar.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-15: CBA - Low Gas Price Scenario with NOx and SOx (£ millions)							
Year	**NOx Costs**	**SOx Costs**	**Production Cost Savings**	**Imp. Costs**	**Ongoing Costs**	**Annual Net-Cost Benefit**	**Discounted Net-Cost Benefit**
2011	£1.90	£4.59	£2.31	-£3.85	-£0.16	£4.79	£4.58
2012	£6.16	£12.80	£2.15	£0	-£0.16	£20.95	£19.18
2013	-£1.36	-£3.69	-£1.03	£0	-£0.16	-£6.24	-£5.46
2014	-£0.60	£0.33	£1.01	£0	-£0.16	£0.58	£0.49
2015	£0.21	-£1.28	£0.20	£0	-£0.16	-£1.03	-£0.83
2016	£5.20	£5.28	£0.87	£0	-£0.16	£11.19	£8.59
2017	£10.26	£0.89	-£0.18	£0	-£0.16	£10.81	£7.94
2018	£14.90	£6.34	£2.21	£0	-£0.16	£23.30	£16.36
2019	£11.02	£6.52	£2.77	£0	-£0.16	£20.15	£13.54
2020	£8.56	£3.80	£1.53	£0	-£0.16	£13.72	£8.82
Totals						**£98.23**	**£73.19**
Discounted Demand Side-Benefits							**£0.36**
Total (including Discounted Demand-Side Benefits)							**£73.55**
Source: LE analysis of Ventyx Data							

The Table presented below outlines the total costs from the introduction of P229 for the low gas price scenario excluding NOx and SOx.

The primary costs accrued are production costs. When we exclude NOx and SOx, the total net benefit was £4.65 million pounds. The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-16: CBA – Low Gas Price Scenario without NOx and SOx (£ millions)					
Year	**Production Cost Savings**	**Imp. Costs**	**Ongoing Costs**	**Annual Net-Cost Benefit**	**Discounted Net-Cost Benefit**
2011	£2.31	-£3.85	-£0.16	-£1.70	-£1.63
2012	£2.15	£0	-£0.16	£2.00	£1.83
2013	-£1.03	£0	-£0.16	-£1.19	-£1.04
2014	£1.01	£0	-£0.16	£0.85	£0.71
2015	£0.20	£0	-£0.16	£0.05	£0.04
2016	£0.87	£0	-£0.16	£0.72	£0.55
2017	-£0.18	£0	-£0.16	-£0.34	-£0.25
2018	£2.21	£0	-£0.16	£2.05	£1.44
2019	£2.77	£0	-£0.16	£2.62	£1.76
2020	£1.53	£0	-£0.16	£1.37	£0.88
Totals				**£6.43**	**£4.30**
Discounted Demand Side-Benefits					**£0.36**
Total (including Discounted Demand-Side Benefits)					**£4.65**
Source: LE analysis of Ventyx Data					

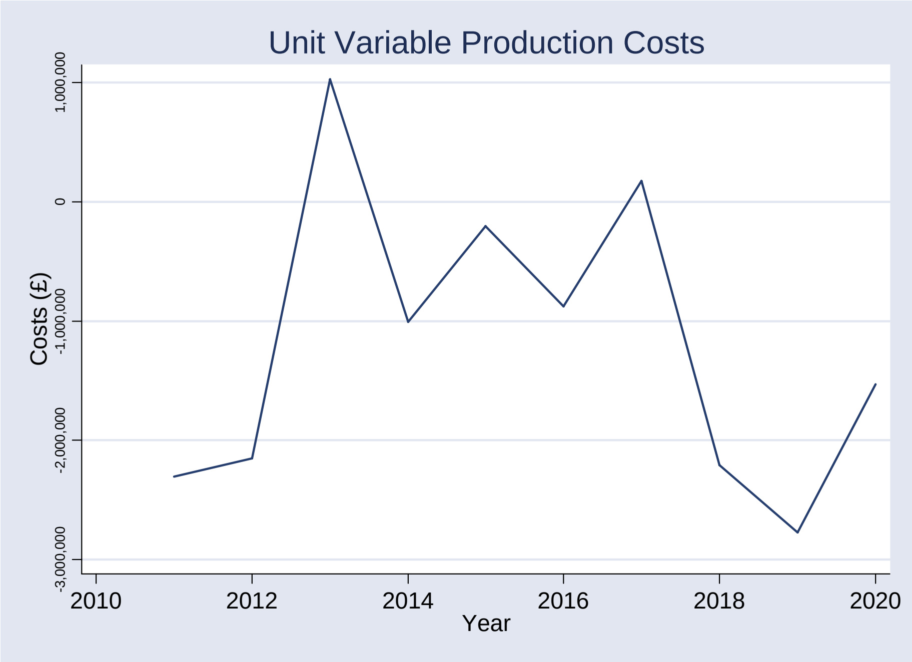
6.3.2.1 Despatch costs

In the low price scenario, as before, the main benefits of P229 derive from lower overall generation costs, as total system generation equals losses plus demand.

The figure below shows the difference between the base case (BAU) and the change case for the low gas price scenario.

The graph trajectory rises initially, specifically after 2012, indicating a fall in cost savings, reaching a minimum level of £1,000,000 pounds. After this point, the model then bears out increases in savings (graph falling) for the remainder of the study period, illustrating savings of £1,000,000 pounds in 2014, roughly £1,000,000 in 2016 and just short of £3,000,000 between 2018 and 2020.

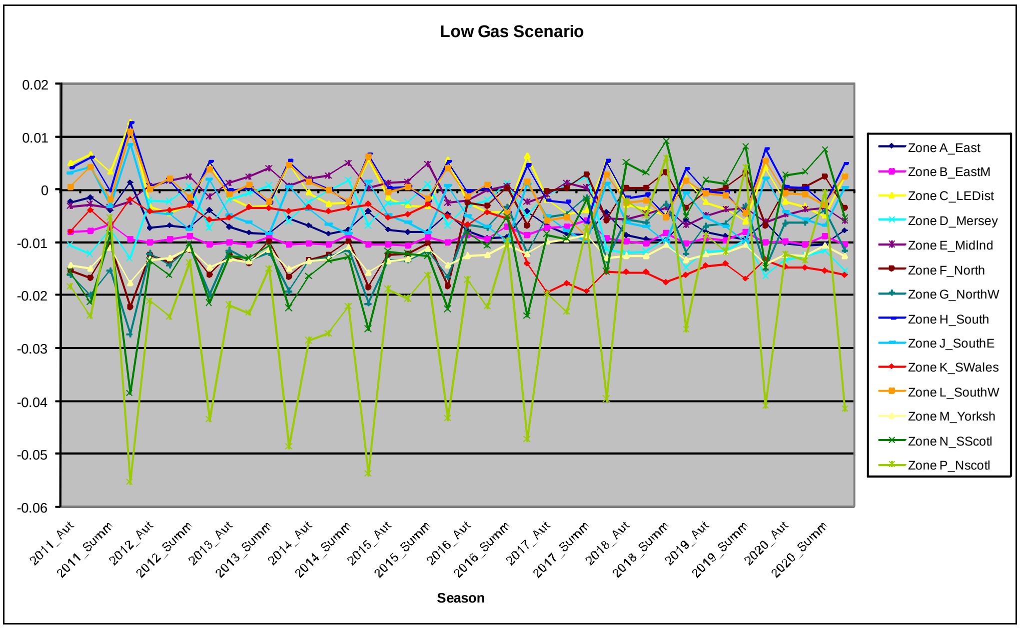
Figure 6-10: Unit Variable Production Costs - Low Gas Prices



Source: LE/Ventyx

6.3.3 Evolved TLFs

Figure 6-11: Low Gas Scenario



Source: LE/Ventyx

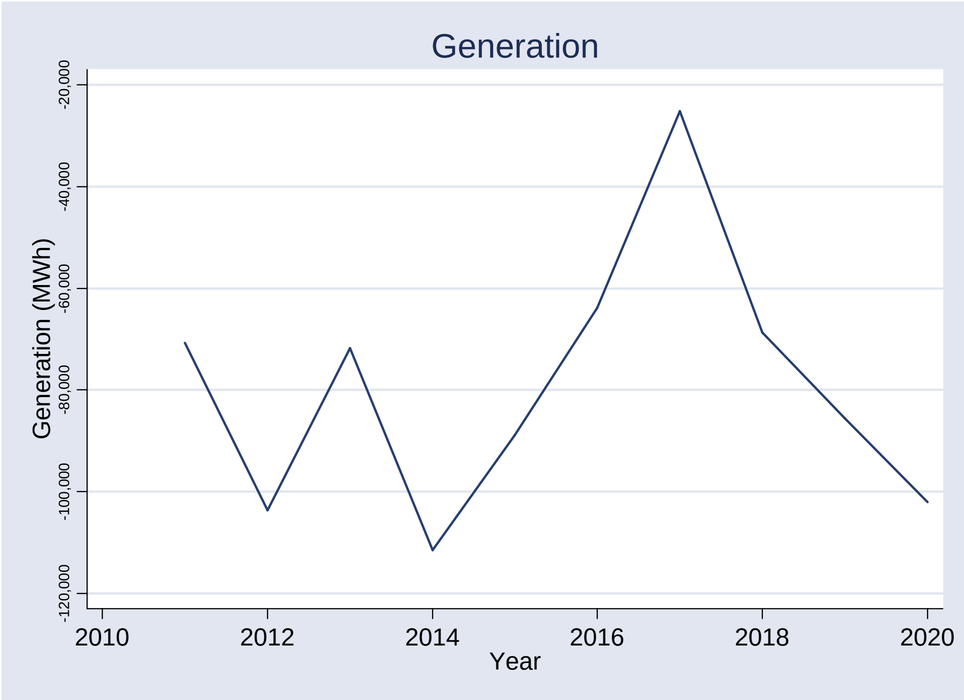
The Figure presented above outlines the evolution of TLFs by zone from the years 2011 to 2020 for the low gas price scenario.

In a similar fashion to the high gas price scenario, the levels for the majority of the zones remain approximately the same over the modelling horizon. Again, most of the volatility within zones can be explained by seasonal changes.

There is a high volatility observed in a few zones including Zone P (Northern Scotland) and to a lesser extent Zone N (Southern Scotland).

6.3.4 Generation

Figure 6-12: Generation - Low Gas Prices



Source: LE/Ventyx

The Figure presented above shows the impact on generation from the introduction of P229 as modelled by the differences between the observed change case minus the base case for the low gas price scenario.

Generation savings for the low price scenario are approximately 100,000 MWh in 2012 and 110,000 in 2014. After 2014, generation savings fall at the outset (graph rising) which suggests that the benefits are reduced over this period as a result of generation. After reaching a minimum of approximately 30,000 MWh in savings, saving benefits increase for the remainder of the study period.

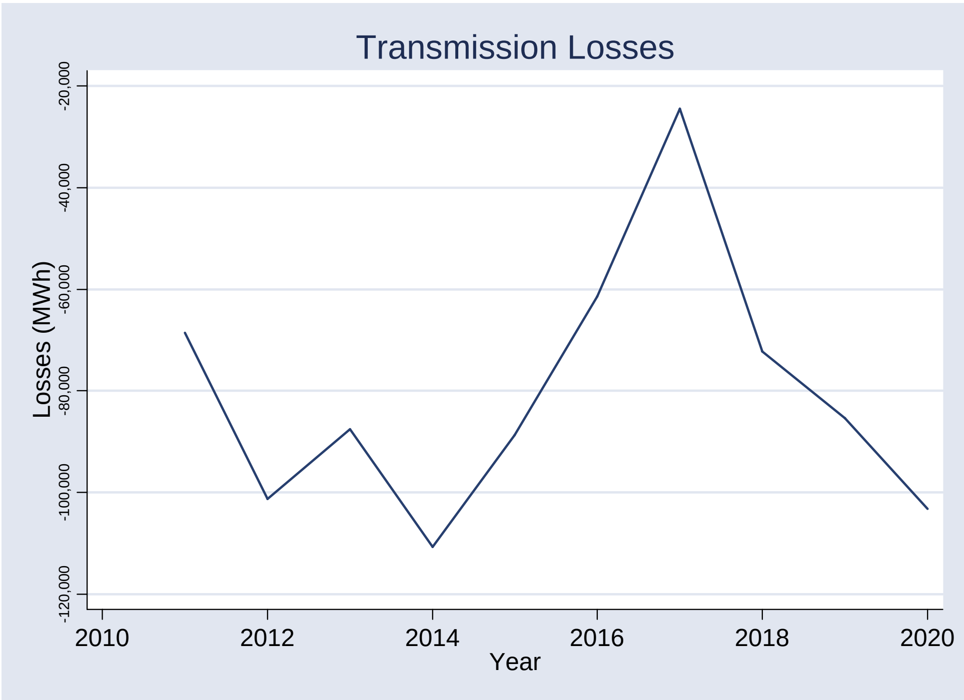
6.3.5 Losses

The Figure presented below shows the (change case minus base case) savings in transmission system losses from the modelled introduction of P229 for the low gas price scenario.

The results show that loss savings per annum are 100,000MWh in 2012 and just below this in 2014. From the start of the analysis we observe lower loss savings up until around 2017 before a sharp reversal results in a sustained period of considerable reduction in transmission losses or loss savings.

The pattern of loss savings correlates with the production cost savings, demonstrating that production cost savings are being determined by loss savings.

Figure 6-13: Transmission Losses: Low Gas Prices



Source: LE/Ventyx

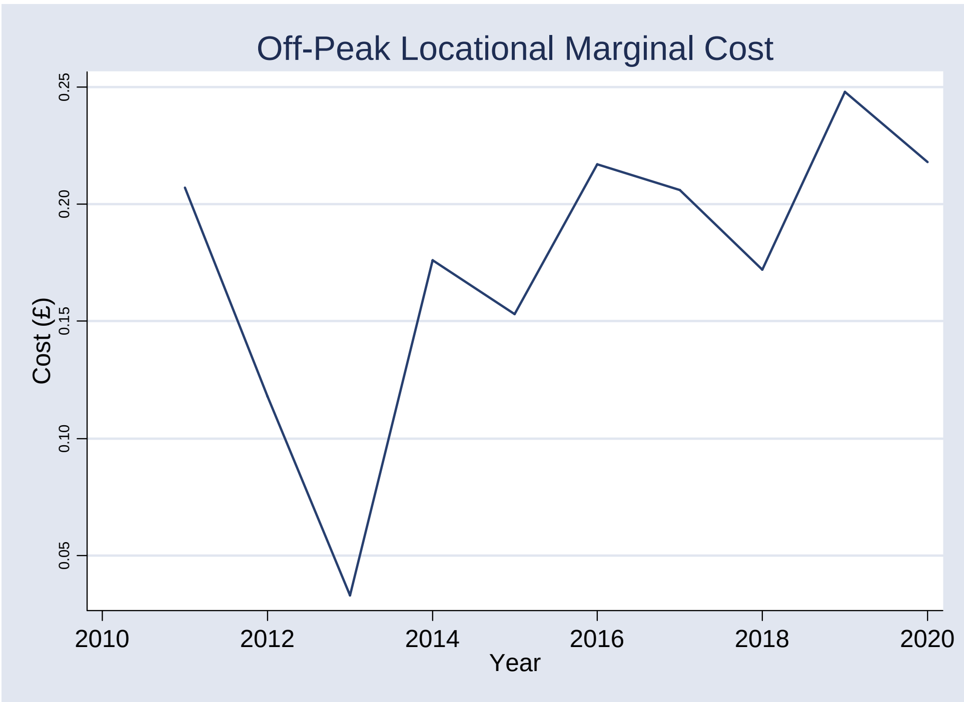
6.3.6 Wholesale prices

To show the pattern of wholesale price changes, we consider the average annual wholesale prices.

We present the results for peak and off-peak price periods, peak being 0800-2000 for Dec to March, 0600-2000 for June to Sept, and 0700-2000 for April, May, and Oct.

In general, since we assume competitive despatch and competitive pricing, the prices are the locational marginal costs from the despatch (LMPs), and are the load weighted-average of the hourly simultaneous optimisation of despatch and transmission.

Figure 6-14: Off-Peak Locational Marginal Cost: - Low Gas Prices



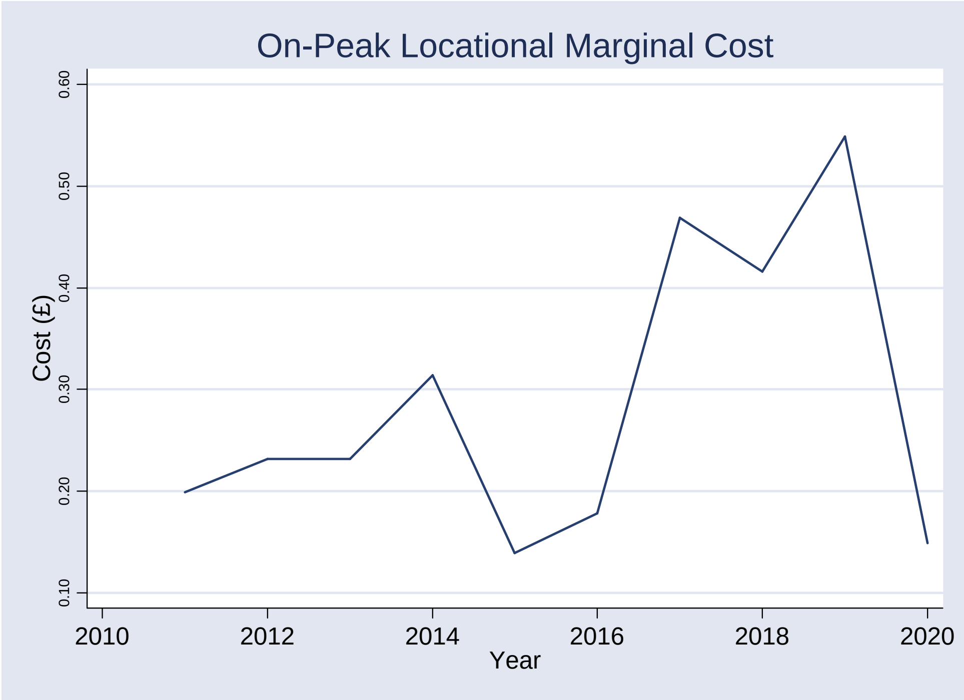
Source: LE/Ventyx

The Figure presented shows the difference between the competitive off-peak LMPs in the change case minus the base case for the low price scenario.

In general, and in line with the high price scenarios, we observe that the LMPs are higher under the change case.

The results show off-peak prices falling initially and subsequently increasing over the study period. The differences found between the two scenarios cases fluctuate from below 5p in 2013 before rising to over 20p by 2016. They reach a peak of 25p between 2018 and 2020.

Figure 6-15: On-Peak Locational Marginal Cost: - Low Gas Prices



Source: LE/Ventyx

The Figure shows the difference between the competitive on-peak LMPs in the change case minus the base case for the low price scenario. Again, we broadly observe that the LMPs are higher under the change case.

The results demonstrate that on-peak prices increased slightly in the period 2012 to 2014. Prices rose from approximately 20p to 30p before falling more than 10p after 2014. After 2015, prices rise to just under 50p before finally surpassing the 50p mark by the end of the study period.

6.3.7 Distributional impacts in CBA from P229

Table 6-17 presents the distribution impacts and transfers, across zones, for the low gas price scenario. To assess the potential size of these transfers at the zonal level, estimates have been calculated based on the results of the system modelling for 2011 and the relevant average load weighted price of electricity (by scenario) in this period.

Table 6-17: Estimate of the distributional impacts and potential transfers – Low Gas Price Scenario

Zone	Demand (TWh)	Supplier TLM	Transfers (£m)	Generation (TWh)	Generator TLM	Transfers (£m)	Net Transfers (£m)
North Scotland	6	0.995	1.62	4	0.982	-0.97	0.65
North West	22	0.998	4.59	18	0.985	-3.05	1.55
South Scotland	20	0.998	3.86	21	0.985	-3.58	0.28
Northern	16	1.000	2.48	10	0.986	-1.15	1.33
Yorkshire	22	1.000	2.94	49	0.987	-4.99	-2.05
Merseyside	13	1.002	0.83	15	0.989	-0.54	0.29
East Midlands	24	1.003	0.95	38	0.990	-0.23	0.72
South Wales	11	1.004	0.09	15	0.991	0.42	0.51
Midlands	26	1.006	-1.19	4	0.993	0.29	-0.89
Eastern	30	1.006	-1.48	22	0.993	1.86	0.38
South East	18	1.008	-2.23	26	0.995	4.10	1.87
South West	16	1.008	-1.95	23	0.995	3.70	1.75
Southern	33	1.009	-5.23	16	0.996	3.17	-2.06
London	29	1.010	-5.30	5	0.997	0.97	-4.32

Source: LE/Ventyx

On the demand side, the results estimate that suppliers in Scotland may receive significant benefits of approximately £5.5 million, while consumers in Northern England may receive £10 million. Overall the analysis of the demand side effect indicates that there is likely to be potential for suppliers in the North of the UK to reduce prices, while for suppliers in the South of the UK will likely be required to increase prices.

On the generation side, the analysis indicates that there would similarly be significant transfers as a result of the introduction of zonal-seasonal loss charging. Generators in Scotland and the North of England are estimated to lose approximately £14 million.

Table 6-18 presents the forecasted changes in generation, by zone, following the introduction of P229 under this scenario.

Table 6-18: Change in Generation by Zone, Low Gas Price Scenario (GWh)

	Year									
Zone	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
East	622	556	154	294	162	42	628	262	130	-396
East Midlands	-175	-1,203	-967	-1,270	-1,186	-1,192	420	700	684	967
London	332	313	310	232	312	234	679	336	279	247
Mersey	-421	553	1,227	1,949	1,925	1,709	501	47	-515	-538
Midlands	97	94	321	329	292	136	148	15	80	21
North	-136	-40	-24	0	0	0	-77	-23	-3	-15
North-West	0	0	0	0	0	0	0	0	0	0
South	797	915	596	584	699	865	1,040	1,227	1,154	1,443
South-East	63	286	64	111	-10	68	162	103	97	274
South Wales	335	598	730	743	511	-77	-1,400	-1,856	-1,635	-1,419
South-West	597	1,003	366	403	432	533	303	449	503	636
Yorkshire	-1,457	-1,979	-2,045	-2,327	-2,317	-1,893	-1,158	-1,239	-1,046	-1,504
South Scotland	-590	-922	-351	-406	-279	-279	-757	-231	115	230
North Scotland	-134	-277	-453	-755	-631	-209	-514	142	71	-48

Source: LE analysis of Ventyx Data

6.3.8 Impacts on the transmission system

Table 6-19: Low gas - Change (%) in total line flows

Voltage (KV)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
132	-0.71%	-0.47%	-0.83%	-1.49%	-1.26%	-0.38%	-0.84%	0.17%	0.23%	-0.16%	-0.38%
275	-0.33%	-0.29%	-0.92%	-1.65%	-1.07%	-0.51%	0.30%	-0.98%	-1.42%	-2.13%	-4.45%
400	-2.33%	-2.88%	-2.04%	-2.18%	-2.17%	-1.85%	-0.98%	-1.68%	-1.91%	-2.36%	-5.74%

Source: LE/Ventyx

The data presented in the above table show the percentage differences between the base case and the change case for the low gas price scenario. The table outlines the percentage changes in total line flows for the modelled horizon.

As in the high gas price scenario, the model shows that for each year and for each of the voltage types there are small but consistent reductions in the levels of line flows. Again, this is intuitive since the overall impact of P229 is to reduce line losses.

Note also that for many of the years under the 400KV voltage scenario, the high gas price scenario displays reductions in line flows which are approximately twice as high as those in the low gas price scenario. In the low gas price scenario, the pattern of flow reductions is, as expected, considerably higher on the higher voltage lines.

6.3.8.1 Congestion

Table 6-20: Annual hours with congestion - Low gas				
Year	**Base**	**Change**	**Diff**	**Diff (%)**
2011	464	425	-39	-8.41%
2012	625	617	-8	-1.28%
2013	517	516	-1	-0.19%
2014	433	381	-52	-12.01%
2015	728	745	17	2.34%
2016	1,466	1,449	-17	-1.16%
2017	423	522	99	23.40%
2018	505	664	159	31.49%
2019	524	596	72	13.74%
2020	629	588	-41	-6.52%
Source: LE/Ventyx				

The Table presented above outlines the annual number of hours with congestion, in the base case and the change case, for the years 2011 to 2020 under the low gas price scenario.

Transmission loss factors reduce aggregate flows which we would expect to further reduce the gap between the base and change case scenarios. The low price scenario displays smaller differences between the two cases when compared with the high price scenario. As before, congestion hours generally increase over time due to increases in load.

In a similar fashion to the high gas price scenario, in terms of annual hours, both the base and change case follow a similar pattern; rising steadily until 2016 and falling thereafter. The nominal and percentage differences, however, fluctuate considerably throughout the modelled horizon. Again, the changes in the later stages may be explained by either unit retirement or new entrants or a combination of both.

6.3.9 Impact on demand

Under the low gas price scenario, the estimated impact on demand-side was £0.36m.

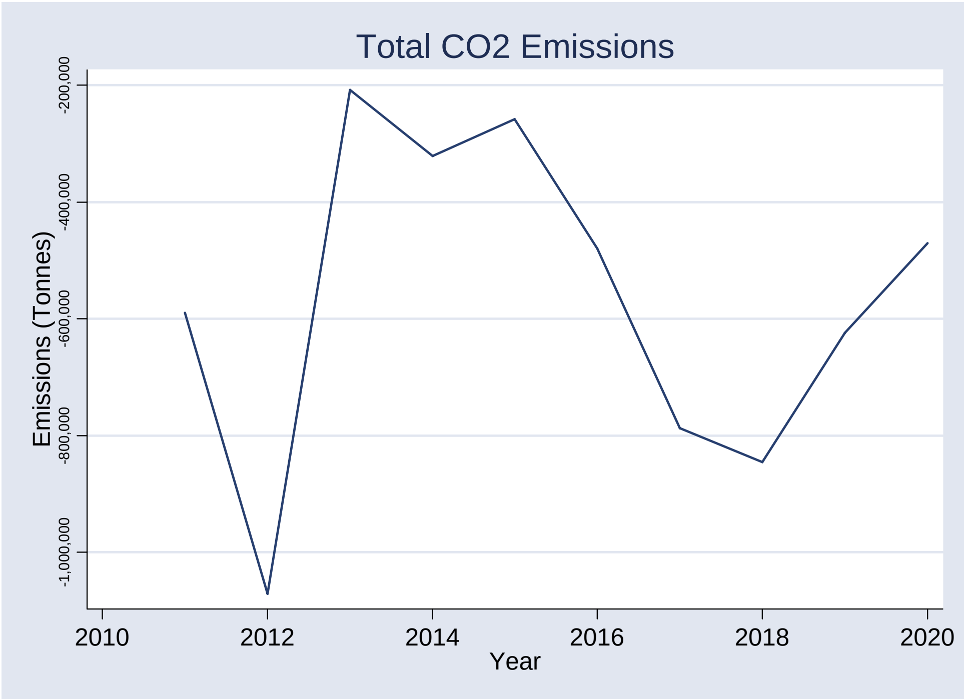
6.3.10 Environmental impacts emissions

The environmental impacts are assumed to be primarily made up of CO2 emissions changes, and SOx and NOx emissions changes. There may be other emissions such as mercury, soot, ash, and particulates, but we have not modelled these.

6.3.10.1 CO2 emissions

The figure below shows the total change in tonnes of CO2 emissions from the modelled high price scenario; the results are again the change case minus the base case.

Figure 6-16: Total CO_2 Emissions - Low Gas Prices



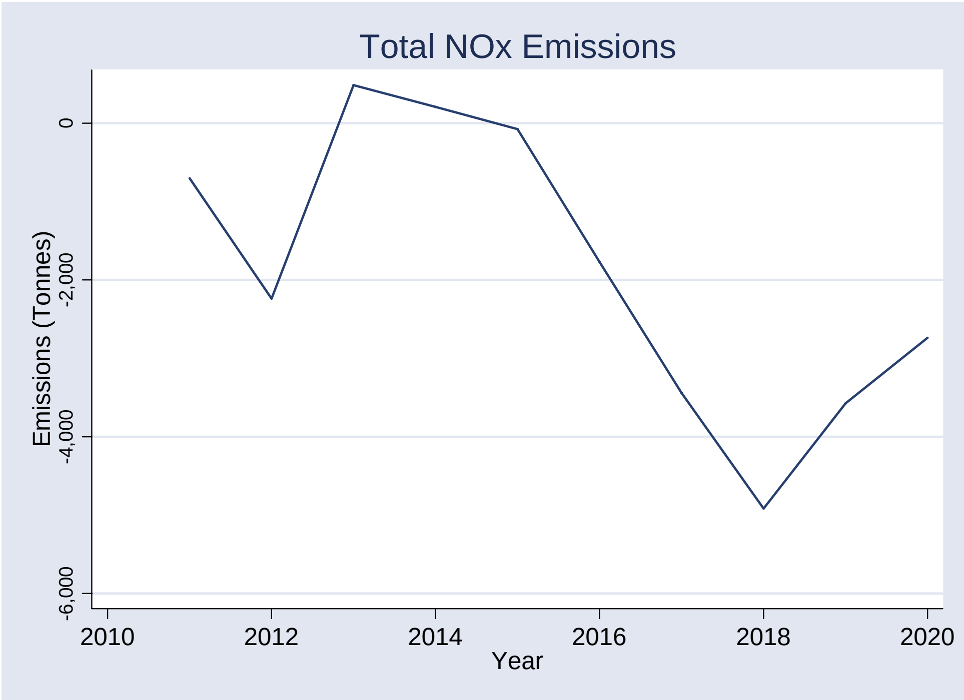
Source: LE/Ventyx

The biggest savings in CO2 emissions come from the year 2012, with over 1 million tonnes saved. Savings fall after this point but the trend begins to rise again around 2015 reaching savings of over 800,000 tonnes in 2018.

6.3.10.2 SOx and NOx emissions

Emissions for sulphur and nitrogen oxides (SOx and NOx) form some of the most important emissions from the production of electric power, the primary damage from these emissions being acid rain and smog.

Figure 6-17: Total NOx Emissions - Low Gas Prices

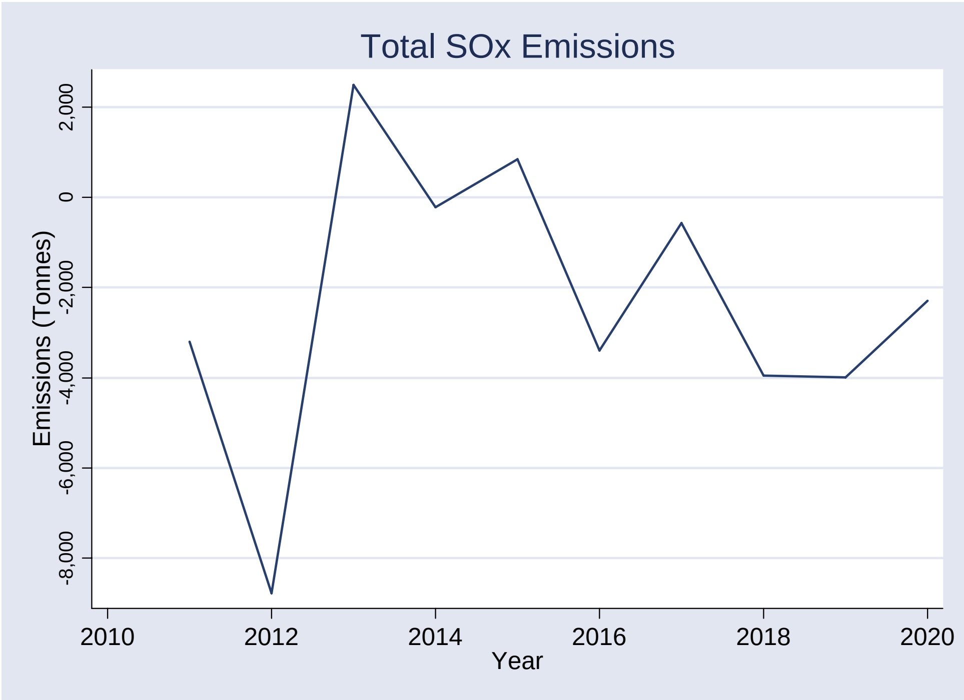


Source: LE/Ventyx

The results in the Figure shown above are the change minus the base case for NOx Emissions in the low gas price scenario.

The results for NOx emissions indicate that there are continued savings in emission in every subsequent year after 2014 up until 2018. The maximum emission saving is in 2018, with over 4,000 tonnes in savings.

Figure 6-18: Total SOx Emissions - Low Gas Prices



Source: LE/Ventyx

The results shown are the change minus the base case for SOx Emissions in the low gas price scenario.

There are significant SOx emissions savings in 2012 with 8,000 tonnes in savings. This is the maximum saving in the low price scenario for both NOx and SOx. In addition, the results show positive savings in most periods after 2014.

In general, the extents of the savings are slightly larger for SOx then they are for NOx for the low price scenario.

6.4 Scenario #3 – Volatile Fuel Price Scenarios

6.4.1 Overview of results: Volatile Fuel Price scenarios

Table 6-21 shows the levels and differences for base and change case results[49] for major variables from the PROMOD modelling.

Table 6-21: Fuel Volatility Sensitivity

	Reference Base	Reference Change	Change - Base	Change - Base	Reference Base	Reference Change	Change - Base	Change - Base
	Production Cost (Billion Pounds Sterling)	Production Cost (Billion Pounds Sterling)	Diff	% Diff	Transmission Losses (TWh)	Transmission Losses (TWh)	Diff (TWh)	% Diff
2011	7.63	7.62	-0.010	-0.13%	3.87	3.63	-0.235	-6.08%
2012	6.88	6.87	-0.007	-0.11%	3.64	3.30	-0.336	-9.24%
2013	6.46	6.46	-0.002	-0.03%	3.45	3.32	-0.138	-4.01%
2014	8.45	8.44	-0.008	-0.10%	4.01	3.85	-0.155	-3.88%
2015	8.09	8.09	-0.001	-0.02%	3.34	3.14	-0.205	-6.13%
2016	7.43	7.43	-0.001	-0.02%	3.28	3.21	-0.071	-2.17%
2017	9.25	9.25	-0.005	-0.05%	3.79	3.70	-0.099	-2.61%
2018	9.92	9.91	-0.012	-0.12%	3.92	3.71	-0.204	-5.21%
2019	8.54	8.54	-0.007	-0.08%	3.67	3.53	-0.138	-3.77%
2020	11.00	10.98	-0.017	-0.15%	4.36	4.12	-0.246	-5.63%

Source: LE/Ventyx

6.4.2 Cost-Benefit analysis

The Table presented below depicts the total benefits from the introduction of P229 for the Volatile Fuel Price scenario. The primary benefits are from the emissions savings from NOx and SOx. Our analysis found that the total net benefit from the CBA for P229 under the Volatile Fuel Price scenario was £174.55 million pounds.

[49] The results are on a rolling 'full year' basis, i.e., 2011 is the full year starting in April according to the BSC calendar.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-22: CBA - Volatile Price Scenario with NOx and SOx (£ millions)							
Year	**NOx Costs**	**SOx Costs**	**Production Cost Savings**	**Imp. Costs**	**Ongoing Costs**	**Annual Net-Cost Benefit**	**Discounted Net-Cost Benefit**
2011	-£2.12	-£3.07	£7.93	-£3.85	-£0.16	-£1.26	-£1.21
2012	£20.77	£41.00	£7.83	£0	-£0.16	£69.45	£63.57
2013	£9.02	£18.83	£2.60	£0	-£0.16	£30.29	£26.53
2014	-£0.59	-£1.67	£7.37	£0	-£0.16	£4.95	£4.14
2015	£17.41	£26.07	£1.97	£0	-£0.16	£45.30	£36.32
2016	£10.76	£17.31	£0.74	£0	-£0.16	£28.65	£21.98
2017	£0.20	-£4.40	£3.25	£0	-£0.16	-£1.11	-£0.81
2018	-£6.64	-£12.69	£14.21	£0	-£0.16	-£5.28	-£3.71
2019	£14.11	£20.55	£1.48	£0	-£0.16	£35.99	£24.18
2020	-£4.56	-£12.18	£19.75	£0	-£0.16	£2.85	£1.83
Totals						**£209.83**	**£172.82**
Discounted Demand Side-Benefits							**£1.73**
Total (including Discounted Demand-Side Benefits)							**£174.55**
Source: LE analysis of Ventyx Data							

The Table outlined below shows the total cost benefits from the introduction of P229 for the Volatile Fuel Price scenario without NOx and SOx. The primary benefits are from the production cost savings. The total net gain excluding NOx and SOx was £48.21 million pounds.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-23: CBA - Volatile Price Scenario without NOx and SOx (£ millions)					
Year	**Production Cost Savings**	**Imp. Costs**	**Ongoing Costs**	**Annual Net-Cost Benefit**	**Discounted Net-Cost Benefit**
2011	£7.93	-£3.85	-£0.16	£3.93	£3.76
2012	£7.83	£0	-£0.16	£7.68	£7.03
2013	£2.60	£0	-£0.16	£2.44	£2.14
2014	£7.37	£0	-£0.16	£7.21	£6.04
2015	£1.97	£0	-£0.16	£1.81	£1.45
2016	£0.74	£0	-£0.16	£0.58	£0.45
2017	£3.25	£0	-£0.16	£3.09	£2.27
2018	£14.21	£0	-£0.16	£14.05	£9.87
2019	£1.48	£0	-£0.16	£1.32	£0.89
2020	£19.75	£0	-£0.16	£19.60	£12.59
Totals				**£61.71**	**£46.48**
Discounted Demand Side-Benefits					**£1.73**
Total (including Discounted Demand-Side Benefits)					**£48.21**
Source: LE analysis of Ventyx Data					

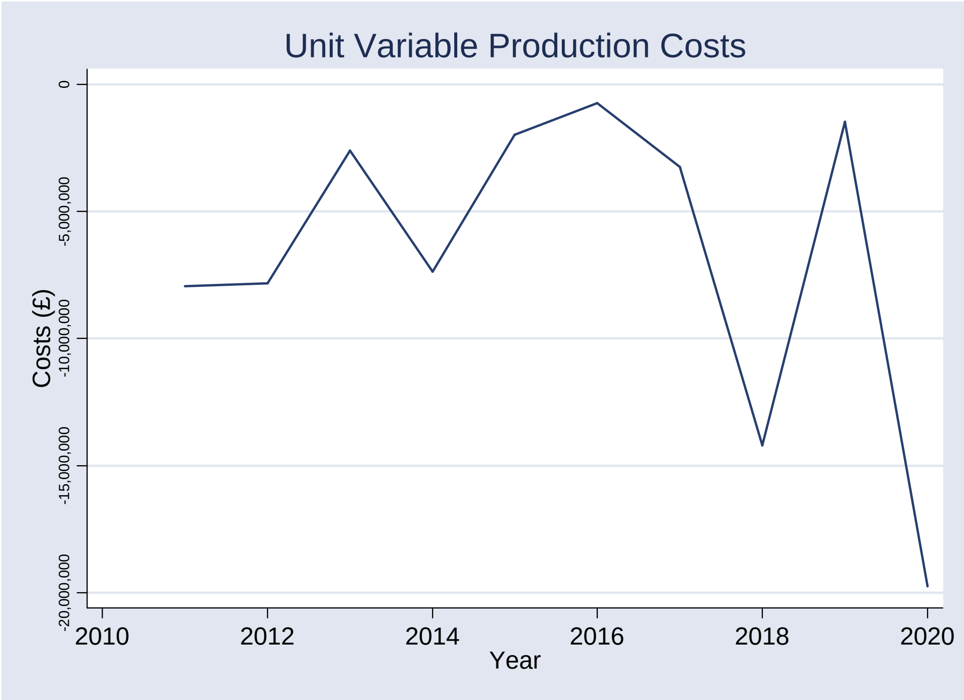
6.4.2.1 Despatch costs

The primary benefits of P229 derive from lower overall generation costs, as total system generation equals losses plus net transmission system demand.

The figure below shows the difference between the base case and the change case for the volatile fuel price scenario.

Production cost savings loosely fluctuate around a savings level of £5m pounds per annum between the 2012 to 2016 period. After this stage, savings increase (graph falling) to just less than £15 million pounds in 2018 and then even further to £20 million by the end of the modelled horizon.

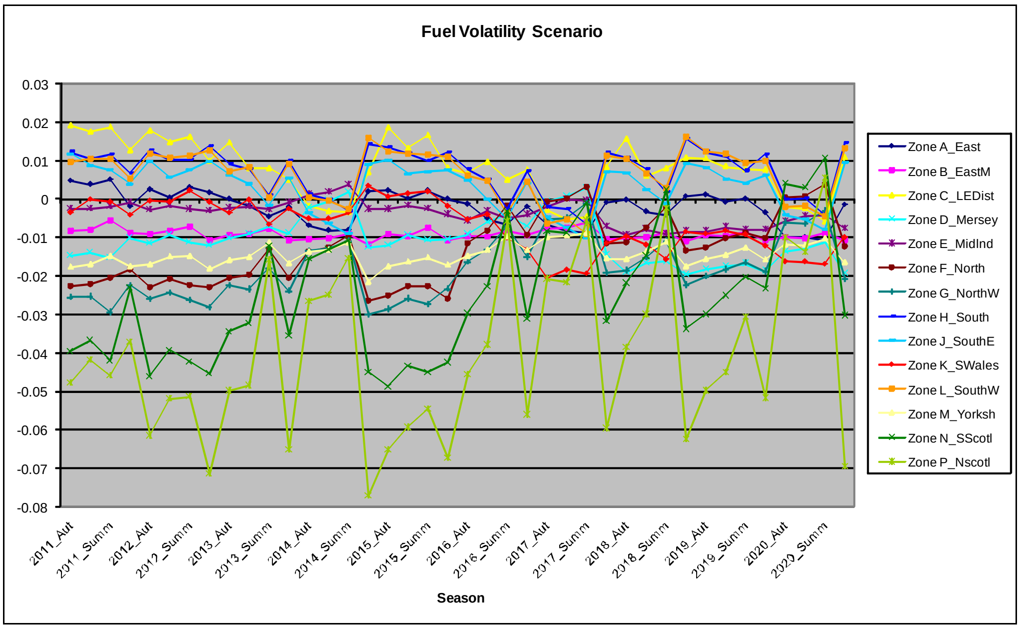
Figure 6-19: Unit Variable Production Costs – Volatile Fuel Price



Source: LE/Ventyx

6.4.3 Evolved TLFs

Figure 6-20: Fuel Volatility Scenario



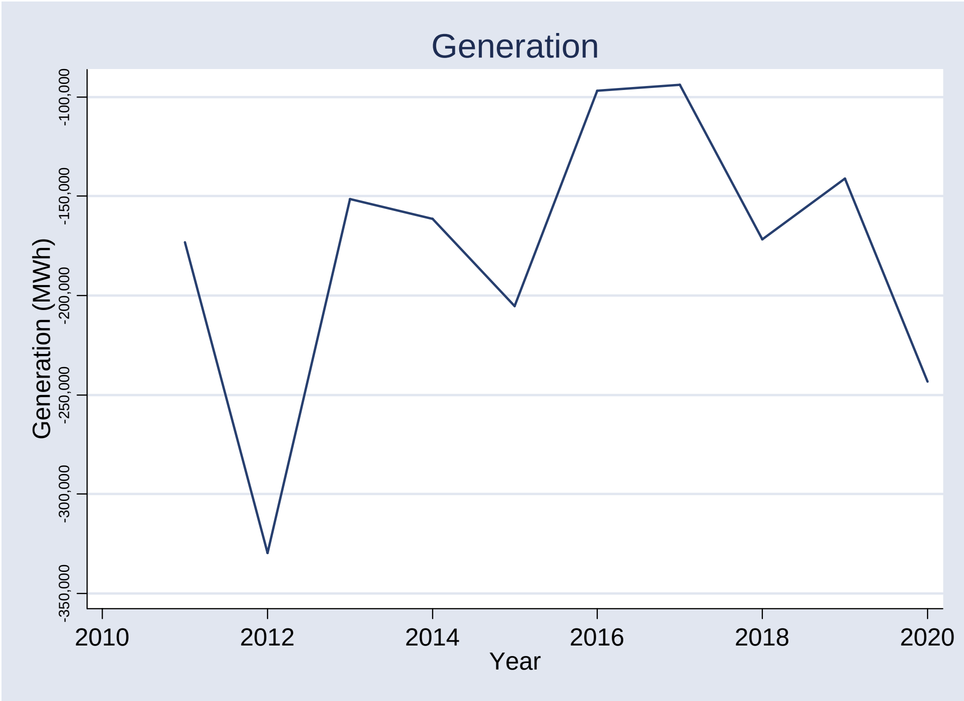
Source: LE/Ventyx

The Figure presented above outlines the evolution of TLFs by zone from the years 2011 to 2020 for the volatile price scenario.

In this modelling scenario, the levels display a higher variability than the high and low price cases. In the initial years, the levels remain approximately flat before showing considerable volatility in the middle years. Once again, Zone P and Zone N experience greater levels of fluctuation than in other zones. Despite this, in many cases the zone levels by the end of the study period are closely in line with their initial levels in 2011.

6.4.4 Generation

Figure 6-21: Generation Change – Volatile Fuel Price



Source: LE/Ventyx

The Figure presented above shows the impact on generation from the introduction of P229 as modelled by the differences between the observed change case minus the base case for the volatile fuel price scenario.

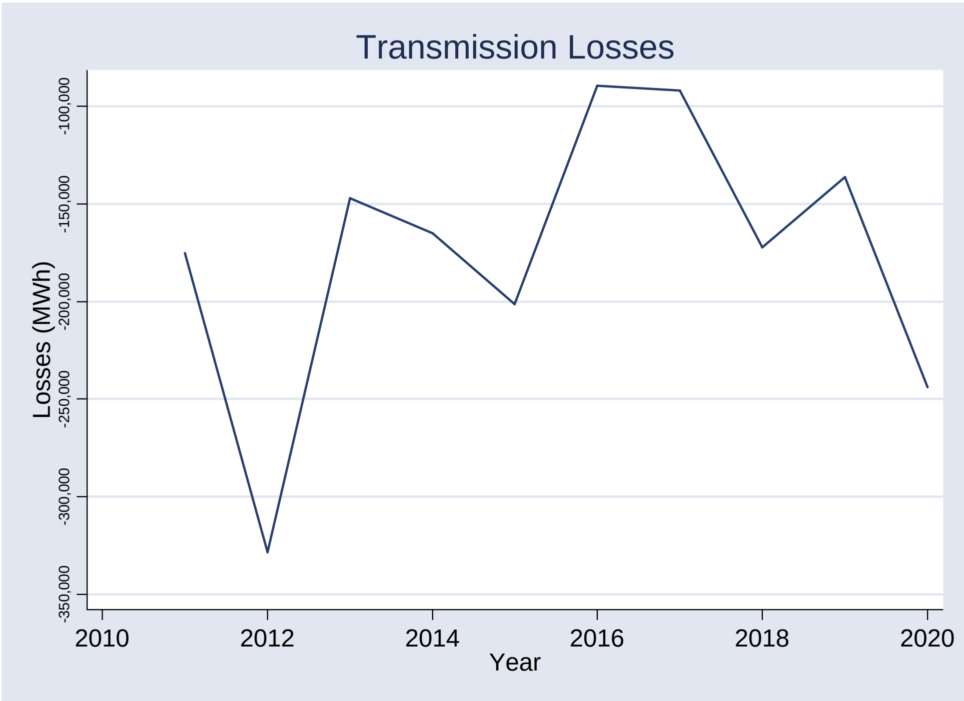
The analysis of generation shows larger benefits in 2012, and then this pattern reverses between 2012 and 2016 where there are smaller savings in generation.

6.4.5 Losses

The Figure presented below shows the (change case minus base case) savings in transmission losses from the modelled introduction of P229 for the volatile fuel price scenario.

The results show that loss benefits per annum are significant; surpassing 300,000MWh in 2012. Following this, we observe a period of lower loss savings in the middle years between 2012 and 2017.

Figure 6-22: Transmission Losses – Volatile Fuel Price

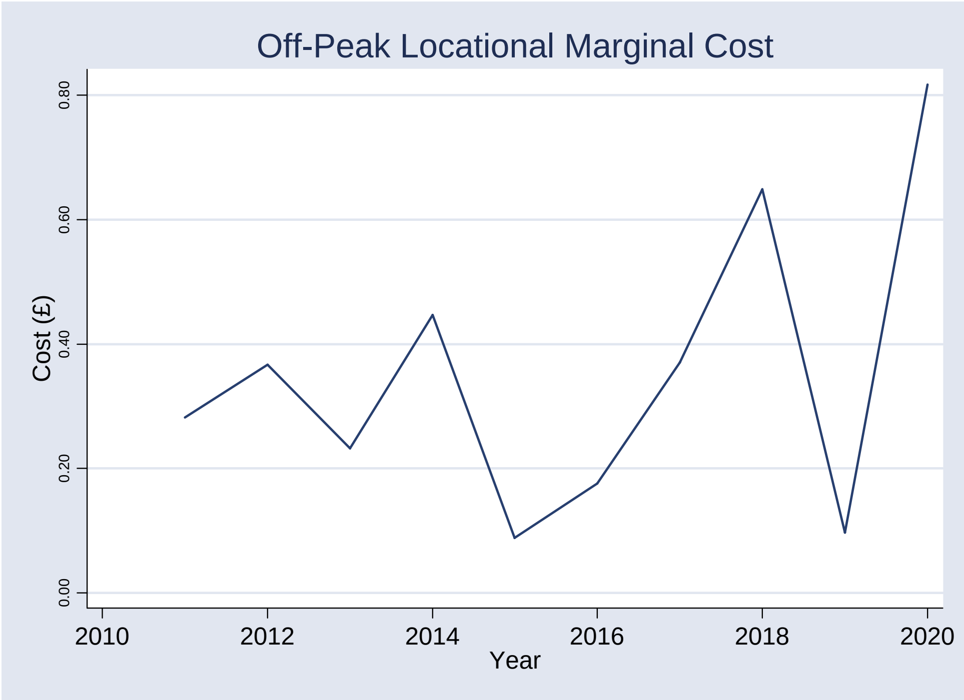


Source: LE/Ventyx

6.4.6 Wholesale prices

To show the pattern of wholesale price changes, we consider the average annual wholesale prices. We present the results for peak and off-peak price periods.

Figure 6-23: Off-Peak Locational Marginal Cost – Volatile Fuel Price

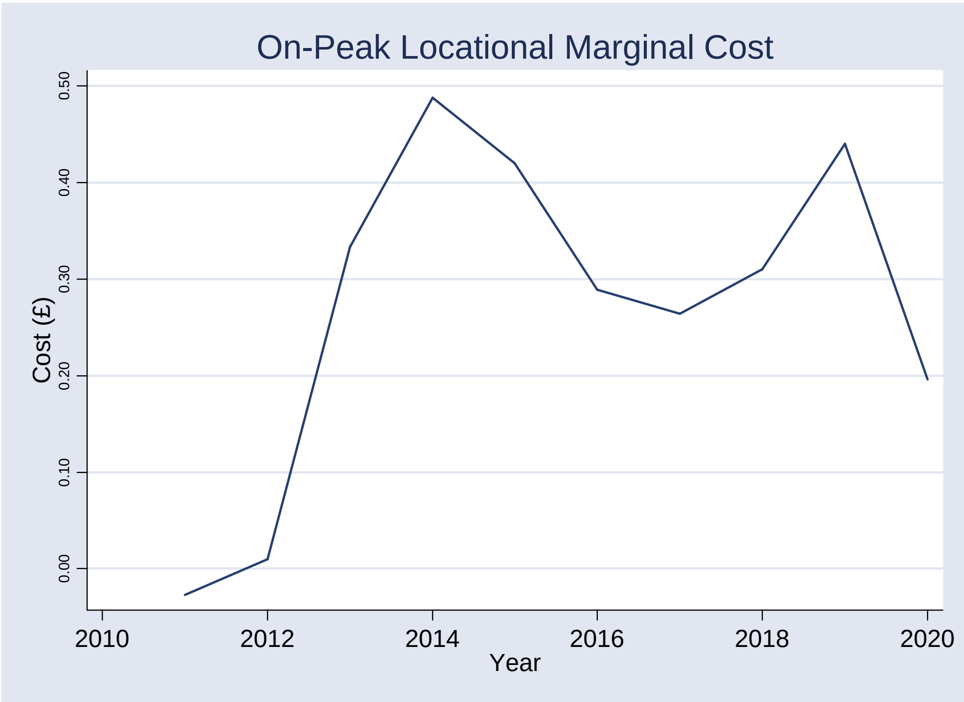


Source: LE/Ventyx

The Figure above shows the difference between the competitive off-peak LMPs in the change case minus the base case for the Volatile Fuel Price scenario. In general, and as in previous scenarios, the LMPs are higher under the change case scenario.

Despite high variation in the price trajectory throughout the modelling horizon, the results show an overall sustained increase in off-peak prices over the study period. The differences between scenarios fluctuate from over 40p in 2014 to approximately 10p in 2015, from over 50p in 2018 to approximately 10p in 2019 and finally to a peak of over 60p in 2020.

Figure 6-24: On-Peak Locational Marginal Cost – Volatile Fuel Price



Source: LE/Ventyx

The Figure presented shows the differentials between the competitive on-peak LMPs in the change case minus the base case for the Volatile Fuel Price scenario. Again, the competitive LMPs are higher for the change case.

The pattern of on-peak price differences moves from roughly zero in 2012 to marginally less than 50p in 2014. This is then followed by modest declines over the next six years until the end of the study period.

6.4.7 Distributional impacts in CBA from P229

Table 6-24 presents the results for the distributional impacts and potential transfers, across zonal areas, under the volatile price scenario. As in previous scenarios, the estimates have been calculated based on the results of the system modelling for the year 2011.

Table 6-24: Estimate of the distributional impacts and potential transfers – Volatile Price Scenario

Zone	Demand (TWh)	Supplier TLM	Transfers (£m)	Generation (TWh)	Generator TLM	Transfers (£m)	Net Transfers (£m)
North Scotland	6	0.982	5.48	2	0.969	-1.99	3.49
South Scotland	20	0.987	15.00	35	0.974	-21.44	-6.45
North West	22	0.994	10.82	18	0.981	-5.75	5.07
Northern	16	0.996	6.12	8	0.983	-1.67	4.45
Yorkshire	22	0.999	5.70	48	0.986	-4.98	0.72
Merseyside	13	1.000	2.44	16	0.987	-0.58	1.86
East Midlands	24	1.003	1.43	60	0.990	5.82	7.25
Midlands	26	1.006	-1.77	8	0.993	1.75	-0.02
South Wales	11	1.006	-0.94	20	0.993	4.78	3.84
Eastern	30	1.009	-5.95	12	0.996	4.26	-1.69
South East	18	1.012	-5.93	17	0.999	8.14	2.21
South West	16	1.012	-5.50	16	0.999	8.08	2.58
Southern	33	1.013	-12.42	6	1.000	3.39	-9.03
London	29	1.015	-14.47	0	1.002	0.20	-14.28

Source: LE/Ventyx

On the demand side, the results estimate that suppliers in the North (Scotland and North England) will receive a significant total benefit of approximately £43 million. These results indicate that there may be potential for Northern suppliers to reduce prices.

On the generation side, generators in Scotland are estimated to lose approximately £23 million, with Southern generators gaining approximately £36 million.

Table 6-25 presents the forecasted changes in generation, by zone, following the introduction of P229 under this scenario.

Table 6-25: Change in Generation by Zone, Volatile Price Scenario (GWh)

	Year									
Zone	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
East	473	1,099	880	-68	965	766	117	344	820	-875
East Midlands	-602	-1,335	-1,117	-1,383	-553	-602	-116	531	200	1,430
London	110	195	534	54	247	332	108	103	425	187
Mersey	-549	-693	-379	294	-616	-57	829	-833	-1,253	-519
Midlands	76	-3	158	89	10	-2	43	-785	-188	-221
North	0	-52	2	0	0	0	-162	-754	-149	-398
North-West	0	0	0	0	0	0	0	0	0	0
South	856	2,502	1,750	1,142	2,544	1,383	811	1,829	2,271	2,140
South-East	224	1,027	372	-115	687	353	-275	-520	571	-163
South Wales	671	870	597	576	301	257	-1,044	197	-497	-2,574
South-West	1,438	2,822	1,069	1,207	2,562	1,394	517	1,499	1,755	1,956
Yorkshire	-2,450	-2,845	-2,068	-1,930	-2,692	-2,351	-1,094	-1,902	-2,371	-1,473
South Scotland	-364	-3,856	-1,549	17	-3,577	-1,286	248	210	-1,389	312
North Scotland	-56	-62	-402	-44	-85	-284	-77	-90	-335	-47

Source: LE analysis of Ventyx Data

6.4.8 Impacts on the transmission system

Table 6-26: Fuel Volatility - Change(%) in total line flows

Voltage (KV)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
132	-0.46%	-0.30%	-1.05%	-0.04%	-0.30%	-0.61%	-0.42%	-0.13%	-0.43%	0.02%	-0.18%
275	-1.13%	-0.82%	-0.41%	-0.59%	0.12%	-0.79%	-1.19%	-0.90%	-0.60%	-1.61%	-2.83%
400	-5.32%	-7.74%	-3.76%	-3.43%	-6.06%	-2.95%	-1.67%	-4.80%	-4.26%	-5.84%	-9.85%

Source: LE/Ventyx

The data presented in the above table shows the percentage differences between the base case and the change case for the fuel volatility scenario. The data charts the percentage change in total flows, for each of the years from 2011 to 2021, by voltage level.

In each year, on aggregate for each voltage type, the model is predicting small reductions in line flows as we would expect.

As in the previous scenarios, the pattern of flow reductions is progressively higher as we increase the voltage levels. This is, again, as expected, since the higher voltage lines are more likely to transport power over longer distances.

6.4.8.1 Congestion

An alternative way to study the impact on the system is to study congestion. The PROMOD modelling software generates LMPs and divergences in LMPs at any given time are an indication of the value-loss due to congestion on the HV system (the LMP which is different from the system price being generated by the marginal cost of the generator within the congested zone which has become functionally separated from the rest of the system). The results as a count of hours where LMPs differ can be found in the table below.

Table 6-27: Annual hours with congestion - Fuel Volatility

Year	Base	Change	Diff	Diff (%)
2011	304	267	-37	-12.17%
2012	730	616	-114	-15.62%
2013	430	374	-56	-13.02%
2014	1,989	1,839	-150	-7.54%
2015	1,531	1,395	-136	-8.88%
2016	1,396	1,368	-28	-2.01%
2017	296	268	-28	-9.46%
2018	194	184	-10	-5.15%
2019	228	400	172	75.44%
2020	399	396	-3	-0.75%

Source: LE/Ventyx

The Table presented above outlines the annual number of hours with congestion, in the base case and the change case, for the years 2011 to 2020 under the volatile price scenario.

In general, transmission loss factors have the effect of reducing the differences between the base and change case scenarios. In addition and as in previous scenarios, the general tendency is that congestion hours tend to increase over time due to larger loads which also have a positive time trend.

As in previous scenarios, in terms of pure annual hours of congestion, both the base and change cases follow similar patterns; rising steadily until 2016 and falling thereafter. The rationale for this is the other factors (especially new generation coming online, or generation coming off-line, as the previous year's TLFs may not reflect this) may outweigh the general tendency of increasing congestion with increasing loads. The percentage differences over the study period roughly tend to fall albeit there are a few years of significant variation. The high increase in 2019 should be noted as a percentage increase on what is a low base, and also may reflect some additional uncertainty in later years.

6.4.9 Impact on demand

The total demand side impact from P229 using the methodology described in the reference section is estimated to be £1.73m under the fuel volatility scenario.

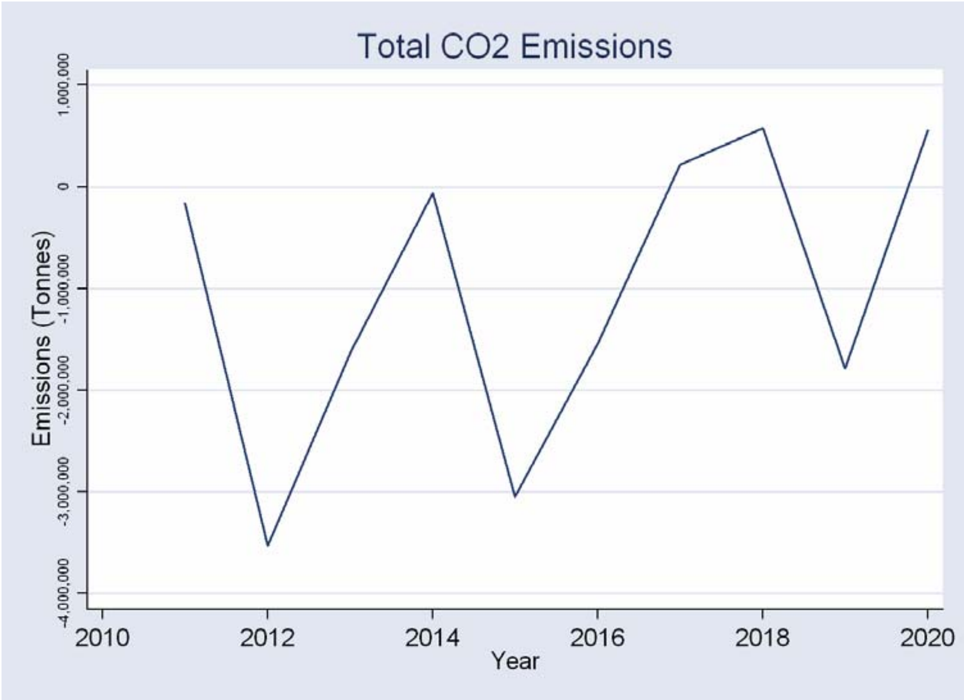
6.4.10 Environmental impacts emissions

The environmental impacts are assumed to be primarily made up of CO_2 emissions changes, and SOx and NOx emissions changes. There may be other emissions such as mercury, soot, ash, and particulates, but we have not modelled these.

6.4.10.1 CO_2 emissions

The figure below shows the total change in tonnes of CO_2 emissions from the modelled Volatile Fuel Price scenario; the results are again the change case minus the base case.

Figure 6-25: Total CO_2 Emissions – Volatile Fuel Price



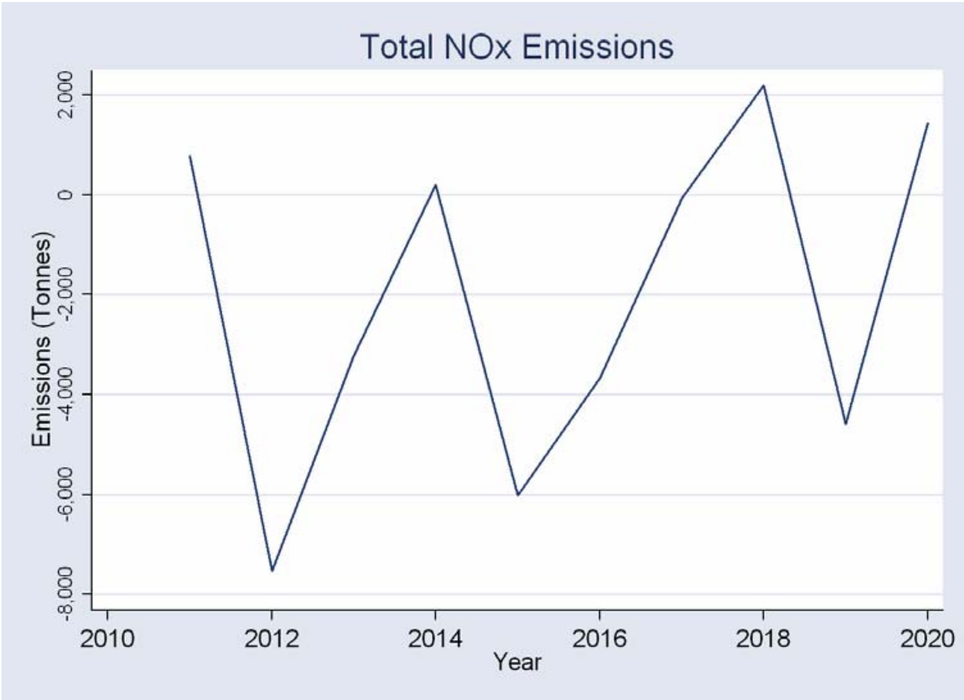
Source: LE/Ventyx

Total CO2 emission savings reach a high level in the first few years and broadly decline over the course of study period albeit with considerable fluctuations. Total CO2 emissions achieve the largest savings in 2012 with approximately 3.5 million tonnes in savings. In addition, there were 3 million tonnes saved in 2015.

6.4.10.2 SOx and NOx emissions

Emissions for sulphur and nitrogen oxides (SOx and NOx) form some of the most important emissions from the production of electric power, the primary damage from these emissions being acid rain and smog.

Figure 6-26: Total NOx Emissions – Volatile Fuel Price

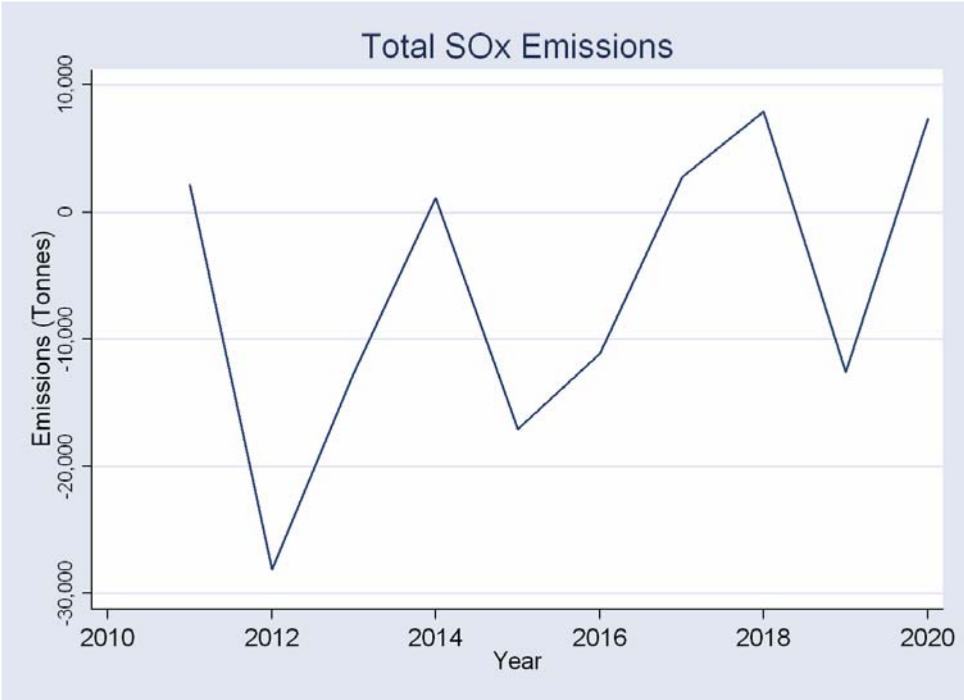


Source: LE/Ventyx

The results shown are the change minus the base case for NOx Emissions in the volatile fuel price scenario. As expected the volatile fuel prices mean emissions savings are volatile, as savings are a function of both loss reductions (total generation lower) and fuel switching, which in this case could go either way, as *relative* fuel prices change.

Total NOx emission savings exceeded 7,000 tonnes at their maximum in 2012. In 2015, savings were 6,000 tonnes. The pattern of NOx emissions broadly increased (depicted as a rising graph) over the study period but with some variation.

Figure 6-27: Total SOx Emissions – Volatile Fuel Price



Source: LE/Ventyx

The results shown are the change minus the base case for SOx Emissions in the volatile fuel price scenario.

Total SOx emissions fluctuate in a similar pattern to the NOx and CO2 emissions but do so on a considerably differing scale. SOx emission savings exceed 25,000 per year in 2012 and 15,000 per year in 2015. The magnitudes of the SOx emission savings are significantly greater than the NOx by approximately a factor of 2.5 - 3.5. Again, given that the SOx and NOx marginal abatement costs are £1,000 - £2,000; this will result in cost savings from SOx being one of the most important determinants of benefits from P229.

6.5 Scenario #4 – Aggressive Offshore Wind Development

6.5.1 Overview of results: Aggressive Offshore Wind Development

Table 6-28 shows the levels and differences for base and change case results[50] for major variables from the PROMOD modelling.

Table 6-28: Aggressive Offshore Wind Sensitivity

	Reference Base	Reference Change	Change - Base	Change - Base	Reference Base	Reference Change	Change - Base	Change - Base
	Production Cost (Billion Pounds Sterling)	Production Cost (Billion Pounds Sterling)	Diff	% Diff	Transmission Losses (TWh)	Transmission Losses (TWh)	Diff (TWh)	% Diff
2011	6.96	6.95	-0.010	-0.14%	3.83	3.56	-0.274	-7.16%
2012	7.07	7.06	-0.007	-0.10%	3.76	3.45	-0.306	-8.16%
2013	7.30	7.29	-0.007	-0.09%	3.71	3.50	-0.204	-5.50%
2014	7.57	7.56	-0.006	-0.08%	3.66	3.44	-0.216	-5.90%
2015	8.22	8.21	-0.006	-0.07%	3.43	3.26	-0.171	-5.00%
2016	8.43	8.43	-0.005	-0.06%	3.57	3.45	-0.126	-3.54%
2017	8.69	8.69	-0.005	-0.05%	3.90	3.75	-0.151	-3.87%
2018	8.90	8.89	-0.010	-0.12%	3.99	3.74	-0.247	-6.20%
2019	9.29	9.28	-0.010	-0.11%	4.04	3.78	-0.262	-6.49%
2020	9.41	9.39	-0.012	-0.12%	4.14	3.87	-0.278	-6.71%

Source: LE/Ventyx

6.5.2 Cost-Benefit analysis

The Table presented below shows the total cost benefits from the introduction of P229 for the aggressive offshore wind development scenario.

[50] The results are on a rolling 'full year' basis, i.e., 2011 is the full year starting in April according to the BSC calendar.

The primary benefits are from loss reductions and the largest benefits are from the emissions savings from NOx and SOx. Our CBA analysis found that the total net benefit for P229 under the aggressive offshore wind development scenario was £267.76 million pounds.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-29: CBA - Wind Development Scenario with NOx and SOx (£ millions)

Year	NOx Costs	SOx Costs	Production Cost Savings	Imp. Costs	Ongoing Costs	Annual Net-Cost Benefit	Discounted Net-Cost Benefit
2011	£4.88	£11.62	£7.41	-£3.85	-£0.16	£19.90	£19.04
2012	£19.31	£38.01	£7.32	£0	-£0.16	£64.48	£59.03
2013	£10.28	£17.16	£6.75	£0	-£0.16	£34.03	£29.81
2014	£8.41	£17.02	£6.88	£0	-£0.16	£32.16	£26.95
2015	£10.79	£22.56	£5.30	£0	-£0.16	£38.49	£30.86
2016	£7.86	£13.97	£4.55	£0	-£0.16	£26.22	£20.11
2017	£8.33	£11.64	£4.45	£0	-£0.16	£24.26	£17.81
2018	£8.17	£17.83	£8.59	£0	-£0.16	£34.43	£24.17
2019	£6.69	£13.42	£10.63	£0	-£0.16	£30.58	£20.54
2020	£6.89	£9.15	£11.54	£0	-£0.16	£27.43	£17.63
Totals						**£331.98**	**£265.94**
Discounted Demand Side-Benefits							**£1.82**
Total (including Discounted Demand-Side Benefits)							**£267.76**

Source: LE analysis of Ventyx Data

The Table presented below outlines the total benefits from the introduction of P229 for the aggressive offshore wind development scenario without NOx and SOx.

The primary benefits are from the production cost savings. Excluding SOx and NOx, the total net benefit was £53.95 million pounds.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-30: CBA - Wind Development Scenario without NOx and SOx (£ millions)					
Year	**Production Cost Savings**	**Imp. Costs**	**Ongoing Costs**	**Annual Net-Cost Benefit**	**Discounted Net-Cost Benefit**
2011	£7.41	-£3.85	-£0.16	£3.40	£3.25
2012	£7.32	£0	-£0.16	£7.16	£6.56
2013	£6.75	£0	-£0.16	£6.59	£5.77
2014	£6.88	£0	-£0.16	£6.72	£5.63
2015	£5.30	£0	-£0.16	£5.14	£4.12
2016	£4.55	£0	-£0.16	£4.39	£3.37
2017	£4.45	£0	-£0.16	£4.29	£3.15
2018	£8.59	£0	-£0.16	£8.43	£5.92
2019	£10.63	£0	-£0.16	£10.47	£7.03
2020	£11.54	£0	-£0.16	£11.39	£7.32
Totals				**£67.99**	**£52.13**
Discounted Demand Side-Benefits					**£1.82**
Total (including Discounted Demand-Side Benefits)					**£53.95**
Source: LE analysis of Ventyx Data					

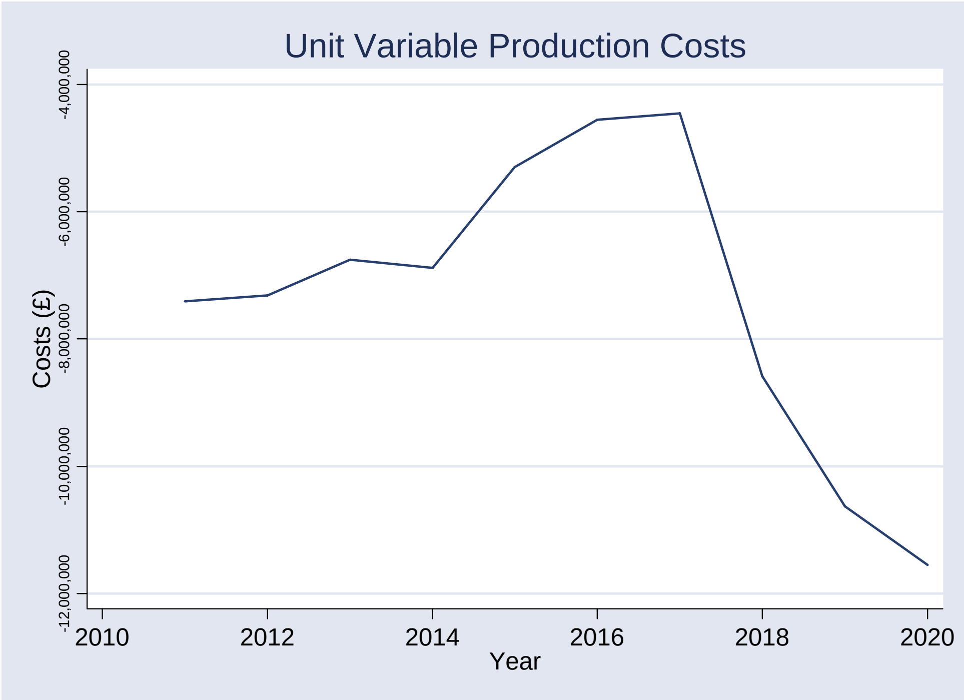
6.5.2.1 Despatch costs

The primary benefits of P229 derive from lower overall generation costs, as total system generation equals losses plus demand.

The figure below shows the difference between the base case (BAU) and the change case for the aggressive offshore wind development scenario.

The figure shows the differences in total production costs from the modelled differences due to the introduction of seasonal and zonal TLFs. The savings are the net lowering of total generation costs, including savings from losses reductions.

Figure 6-28: Unit Variable Production Costs – Offshore Wind Development

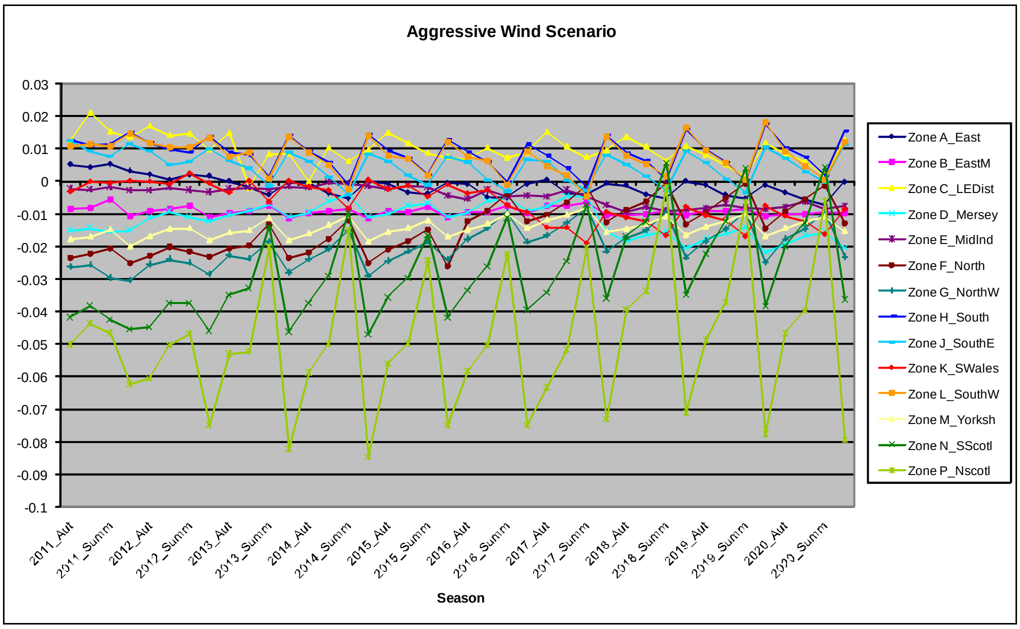


Source: LE/Ventyx

Production cost savings decline moderately and gradually (graph rising) over the years 2012 to 2018. Following this fall, there is an expected increase in savings for the remainder of the analysis with savings exceeding £12.5 million pounds.

6.5.3 Evolved TLFs

Figure 6-29: Aggressive Wind Scenario



Source: LE/Ventyx

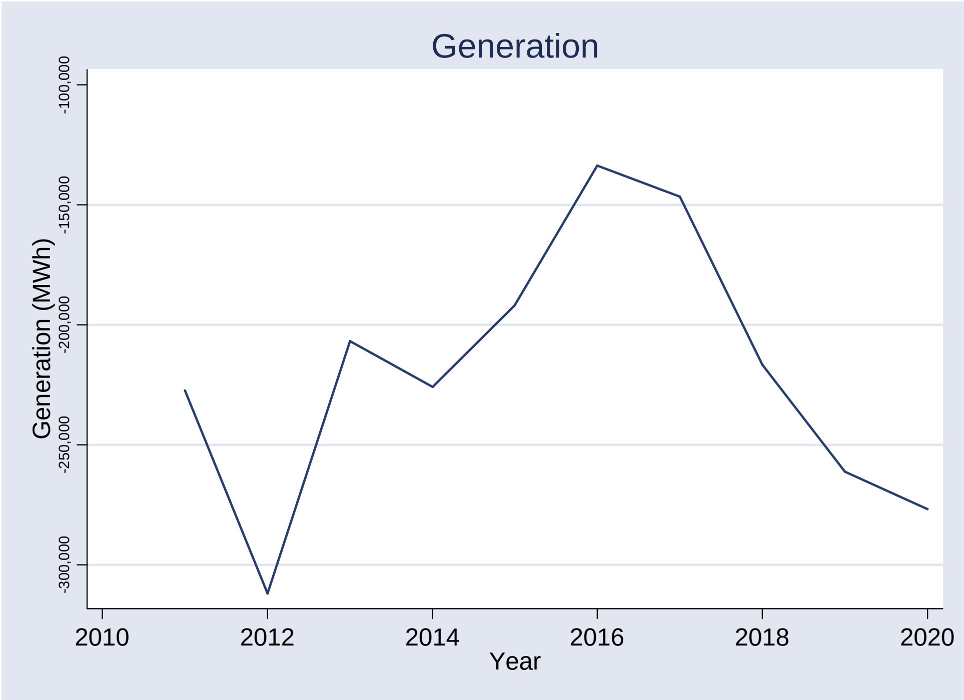
The Figure presented above outlines the evolution of TLFs, by zone, from the years 2011 to 2020 for the aggressive wind development scenario.

In this scenario, the analysis clearly shows that almost all of the variation is arising as a result of seasonal changes. Broadly, over the course of the modelling horizon, the levels of most zones remain roughly the same.

The largest volatility between seasons is found in Zone P (Northern Scotland) and to a lesser extent Zone N (Southern Scotland).

6.5.4 Generation

Figure 6-30: Generation – Offshore Wind Development



Source: LE/Ventyx

The Figure presented above outlines the impact on generation from the introduction of P229 as modelled by the differences between the observed changes minus the base case for the aggressive offshore wind development scenario.

There are significant generation savings in 2012 with savings exceeding 300,000MWh. After 2012, the curve shows a sharp decline in the quantity of savings, until the years between 2016 and 2018, after which there is a return to a rise in savings. There are generation savings in excess of 250,000MWh in 2019 and 2020.

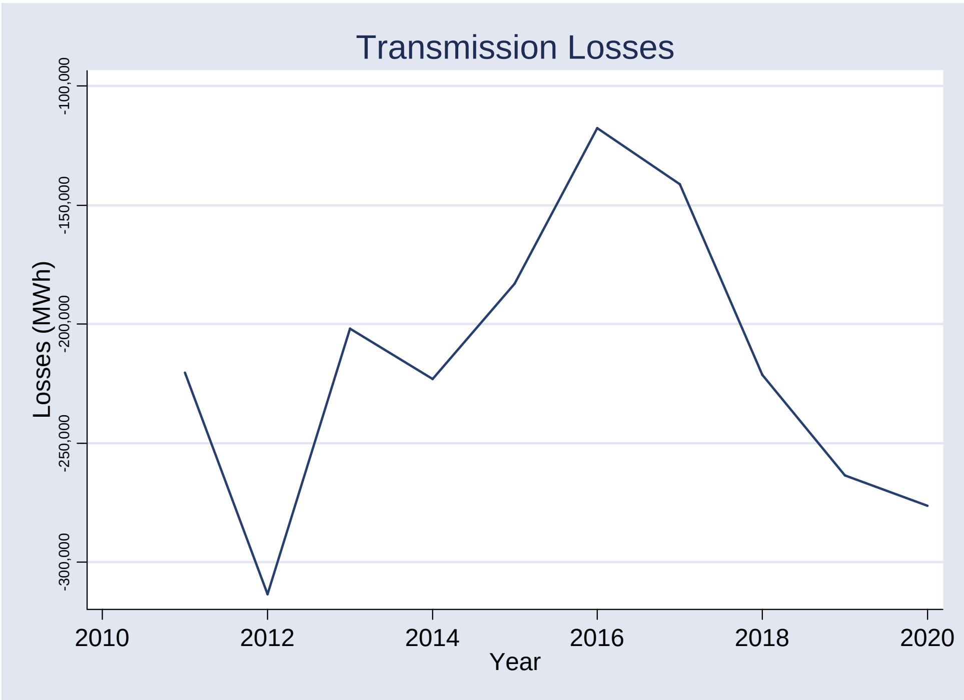
6.5.5 Losses

The Figure outlined below shows the (change case minus base case) savings in transmission system losses from the modelled introduction of P229 for the aggressive offshore wind development scenario.

The results show that there are significant loss savings in 2012 in excess of 300,000MWh per year. These savings then decline over the coming years until approximately 2016 and then major savings are realised again after 2018, with more than 250,000MWh in savings in 2020.

The pattern of loss savings largely mirrors the analysis of production cost savings. This suggests that production cost savings are being determined by loss reductions.

Figure 6-31: Transmission Losses – Offshore Wind Development

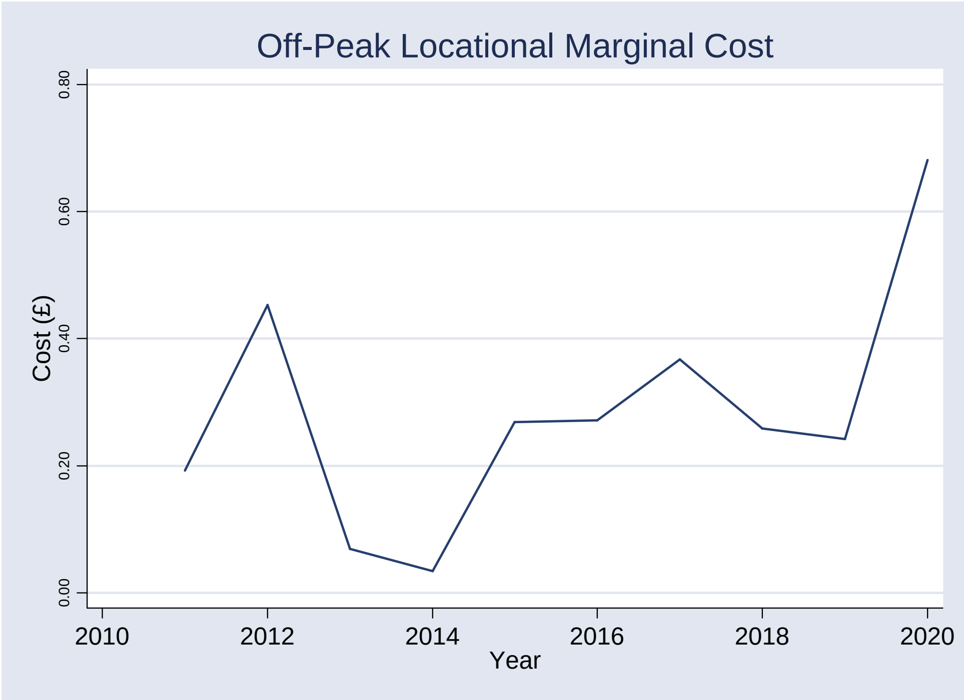


Source: LE/Ventyx

6.5.6 Wholesale prices

To show the pattern of wholesale price changes, we consider the average annual wholesale prices. We present the results for peak and off-peak price periods.

Figure 6-32: Off-Peak Locational Marginal Cost – Offshore Wind Development

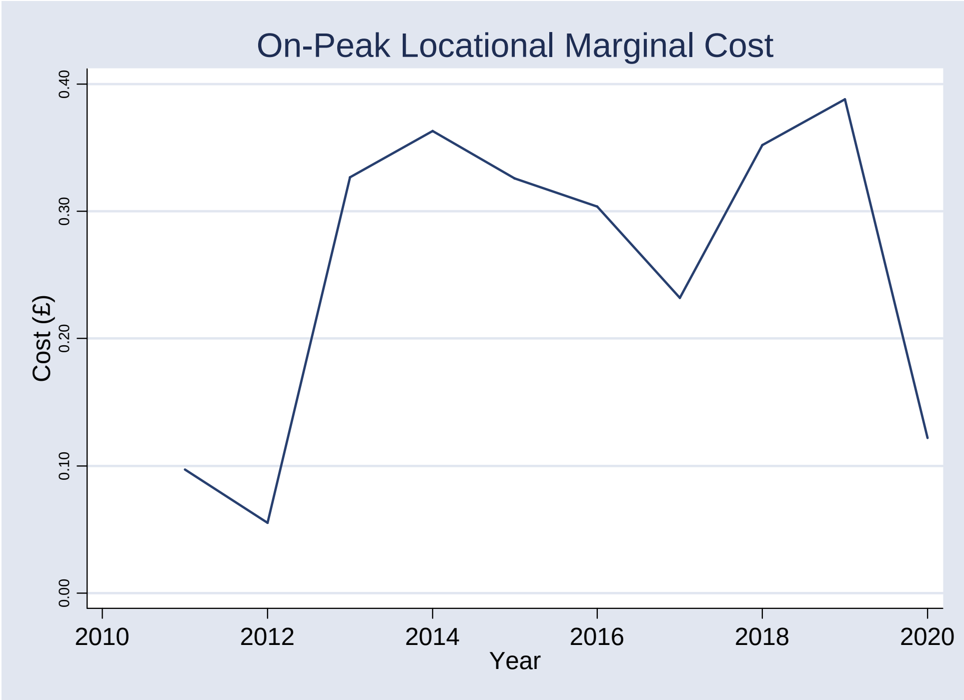


Source: LE/Ventyx

The Figure above shows the difference between the competitive off-peak LMPs in the change case minus the base case for the aggressive offshore wind development scenario. In general, the LMPs are higher under the change case, P229 as expected.

The results show a modest but overall increase in off-peak prices over the study period. The differences between scenarios fluctuate from over 40p in 2012 to less than 5p in 2014. After 2014, there is a steady increase in off-peak prices reaching a maximum price of more than 60p in 2020.

Figure 6-33: On-Peak Locational Marginal Cost – Offshore Wind Development



Source: LE/Ventyx

The figures show the differentials between the competitive on-peak LMPs in the change case minus the base case for the aggressive offshore wind development scenario.

The pattern of on-peak price differences shifts from just under 10p in 2012 to over 30p the following year. The price difference is slightly above 10p in 2020.

6.5.7 Distributional impacts in CBA from P229

Table 6-31 presents the results for the distributional impacts and potential transfers between zones for the offshore wind development scenario. All of the results and estimates have been calculated in the same fashion as in previous scenarios.

Table 6-31: Estimate of the distributional impacts and potential transfers – Wind Development Scenario

Zone	Demand (TWh)	Supplier TLM	Transfers (£m)	Generation (TWh)	Generator TLM	Transfers (£m)	Net Transfers (£m)
North Scotland	6	0.981	5.09	2	0.968	-1.79	3.30
South Scotland	20	0.986	13.96	34	0.973	-19.74	-5.78
North West	22	0.993	9.64	18	0.980	-5.23	4.41
Northern	16	0.996	5.44	8	0.983	-1.53	3.91
Yorkshire	22	0.998	4.93	48	0.985	-4.41	0.52
Merseyside	13	1.000	2.18	16	0.987	-0.61	1.56
East Midlands	24	1.003	1.17	60	0.990	5.07	6.24
Midlands	26	1.006	-1.64	8	0.993	1.51	-0.14
South Wales	11	1.007	-1.01	19	0.993	4.33	3.32
Eastern	30	1.009	-5.65	12	0.996	3.88	-1.76
South East	18	1.012	-5.58	18	0.999	7.76	2.18
South West	16	1.013	-5.25	15	1.000	7.27	2.02
Southern	33	1.013	-11.50	7	1.000	3.38	-8.12
London	29	1.014	-11.78	0	1.001	0.12	-11.66

Source: LE/Ventyx

The results estimate that suppliers/consumers in Scotland may receive significant benefits of approximately £19 million and consumers in Northern England may receive an additional £20 million. In general, these results indicate that there is likely to be a required decrease in prices among suppliers in the North of the UK.

In a similar trend to that found on the demand side, the results show the potential for considerable transfers. Generators in Scotland and the North of England are estimated to lose approximately £32 million while generators located in regions in the South of the UK (Southern, South West, South East) and including London, are expected to benefit by approximately £19 million.

Table 6-32 presents the forecasted changes in generation, by zone, following the introduction of P229 under the aggressive offshore wind development scenario.

Table 6-32: Change in Generation by Zone, Aggressive Offshore Wind Scenario (GWh)

	Year									
Zone	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
East	323	993	442	490	505	306	522	504	-368	-278
East Midlands	-713	-1,361	-1,521	-2,004	-1,087	-1,119	-66	-398	15	673
London	65	157	200	161	225	139	144	185	129	227
Mersey	-537	-645	-685	-135	-483	-566	-348	-1,646	-1,683	-1,721
Midlands	19	-1	-12	23	25	11	18	-450	-448	-491
North	0	-47	-20	0	0	0	-410	-413	-421	-972
North-West	0	0	0	0	0	0	0	0	0	0
South	1,396	2,351	1,970	1,858	1,805	1,836	1,710	2,168	2,421	2,771
South-East	527	1,012	737	798	473	343	284	296	340	690
South Wales	513	825	396	227	71	71	-831	-352	-848	-1,760
South-West	1,173	2,744	2,104	1,837	1,943	1,607	1,266	1,924	2,456	2,394
Yorkshire	-1,952	-2,832	-3,047	-2,228	-2,248	-1,943	-1,138	-1,801	-1,525	-1,592
South Scotland	-994	-3,453	-688	-1,184	-1,341	-770	-1,189	-160	-252	-165
North Scotland	-49	-53	-81	-69	-81	-48	-109	-75	-78	-54

Source: LE analysis of Ventyx Data

6.5.8 Impacts on the transmission system

The data presented in Table 6-33 outlines the percentage differences between the base case and the change case for the offshore wind development scenario. The data in the table shows the percentage change in total flows, for each year between 2011 and 2021, by voltage level.

Table 6-33: Offshore Wind - Change (%) total line flows											
Voltage (KV)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
132	-0.68%	-0.40%	-0.19%	-0.17%	-0.30%	-0.18%	-0.25%	-0.40%	-0.28%	-0.14%	-0.19%
275	-2.72%	-0.99%	-1.17%	-0.66%	-0.98%	-1.08%	-0.80%	-2.37%	-2.21%	-2.58%	-3.17%
400	-5.60%	-7.41%	-5.16%	-5.02%	-5.15%	-4.06%	-3.62%	-5.54%	-6.30%	-6.86%	-9.27%
Source: LE/Ventyx											

For each year and level of voltage, the data shows small decreases in line flows. Again, this is consistent with the overall impact of P229, which is to reduce line losses. As in previous scenarios, flow reductions progress upward to higher voltage levels.

6.5.8.1 Congestion

Table 6-34 outlines the annual number of hours with congestion, in the base case and the change case, for the years 2011 to 2020 under the offshore wind development scenario.

This scenario predicts considerably larger levels of congestion in pure annual hours over the entire course of the study period. The model also predicts that the base case experiences greater hourly congestion but only up until 2014 after which the change case has greater congestion right up until 2020. In general, the percentage differences between the two scenarios become smaller progressively throughout the modelled period.

Table 6-34: Annual Hours with Congestion - Offshore Wind				
Year	**Base**	**Change**	**Diff**	**Diff (%)**
2011	260	169	-91	-35.00%
2012	1,066	922	-144	-13.51%
2013	1,504	1,430	-74	-4.92%
2014	2,067	1,945	-122	-5.90%
2015	2,779	2,814	35	1.26%
2016	4,556	4,556	0	0.00%
2017	1,518	1,598	80	5.27%
2018	1,671	1,746	75	4.49%
2019	1,558	1,572	14	0.90%
2020	1,186	1,201	15	1.26%
Source: LE/Ventyx				

6.5.9 Impact on demand

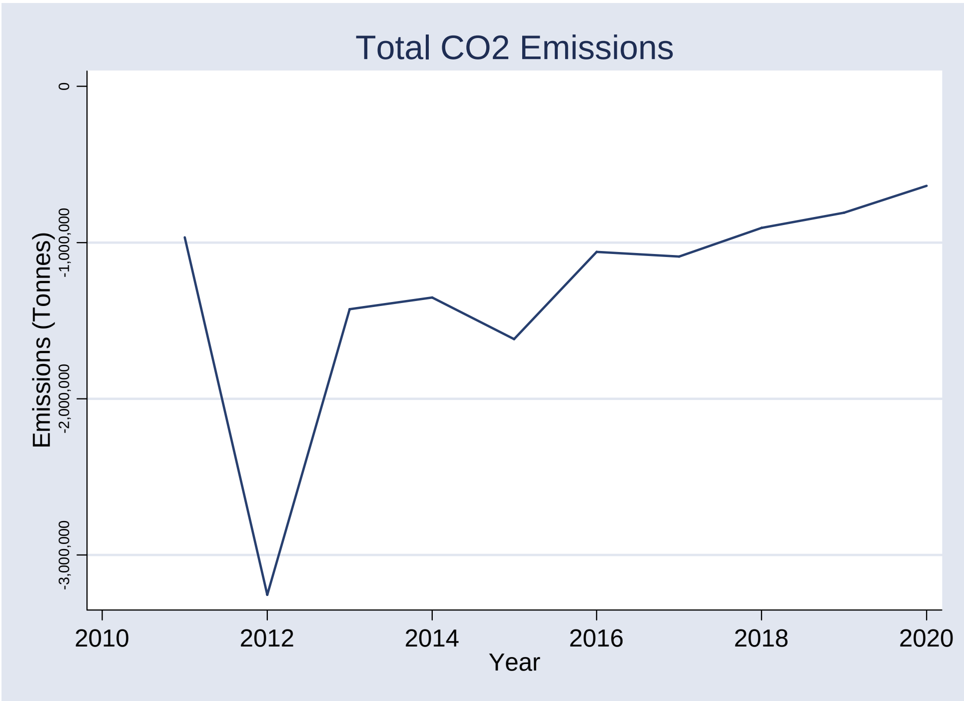
The total demand-side impacts from the aggressive offshore wind scenario were estimated to be £1.73m.

6.5.10 Environmental impacts emissions

6.5.10.1 CO2 emissions

The figure below shows the total change in tonnes of CO2 emissions from the modelled aggressive offshore wind development scenario; the results are again the change case minus the base case.

Figure 6-34: Total CO_2 Emissions – Offshore Wind Development



Source: LE/Ventyx

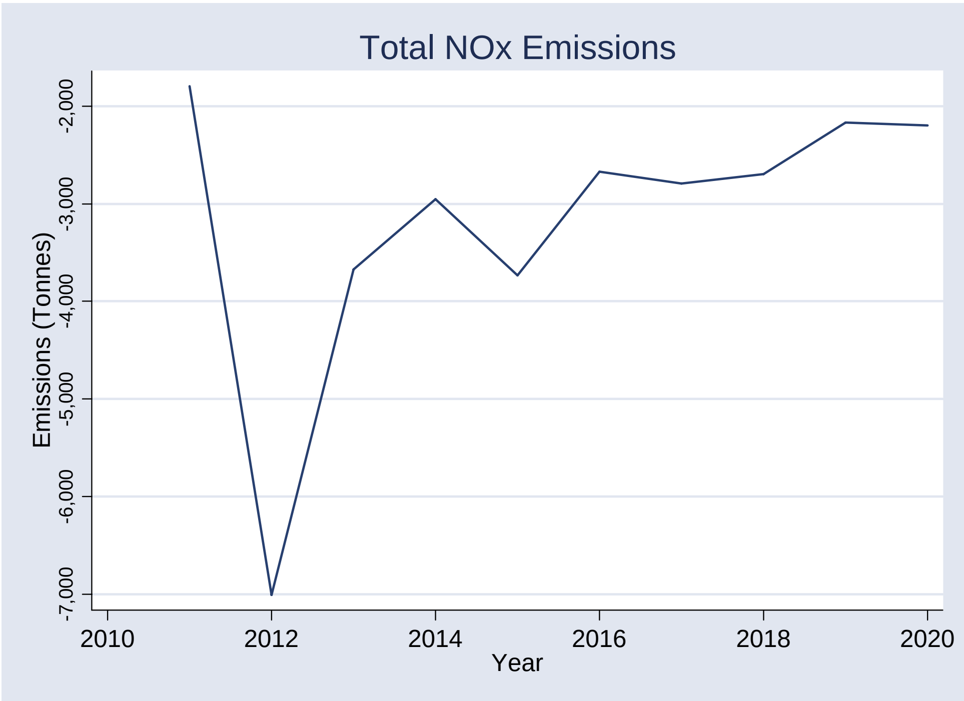
The largest savings in C02 emissions come from the year 2012, with over 3 million tonnes being saved. There is a sharp and then gradual decline (lower levels of savings) for the remainder of the analysis.

6.5.10.2 SOx and NOx emissions

Emissions for sulphur and nitrogen oxides (SOx and NOx) form some of the most important emissions from the production of electric power, the primary damage from these emissions being acid rain.

The results shown are the change minus the base case for NOx emissions in the aggressive offshore wind development scenario.

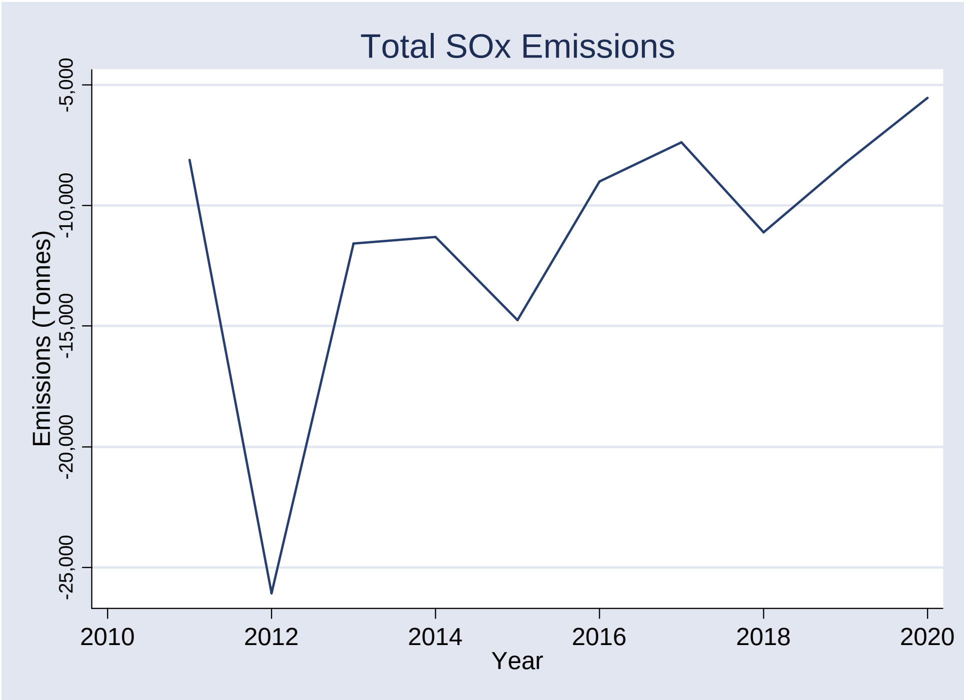
Figure 6-35: Total NOx Emissions – Offshore Wind Development



Source: LE/Ventyx

The results of our analysis on total NOx emissions show the largest savings in 2012, with 7,000 tonnes being saved per year. As with the case of total CO2 emissions, this trend then goes from a sharp to a gradual decline in the levels of savings until the end of the study period.

Figure 6-36: Total SOx Emissions – Offshore Wind Development



Source: LE/Ventyx

The results of our analysis show the largest levels of savings to be 25,000 tonnes saved in 2012. Again, the SOx emissions are strongly correlated with the NOx emissions but are of a differing magnitude. For example, SOx emission savings exceed NOx emission savings by a factor of more than 3 in 2012.

Again, given that the SOx and NOx marginal abatement costs are £1,000 - £2,000, this will result in emissions savings values from SOx being one of the most important determinants of benefits from P229.

6.6 Scenario #5 – Alternative Development of Nuclear Assets

6.6.1 Overview of results: Alternative Development of Nuclear Assets

Table 6-35 shows the levels and differences for base and change case results[51] for overall production costs and transmission losses from the PROMOD modelling.

Table 6-35: Alternative Nuclear Scenario

	Alt Nuclear Base	Alt Nuclear Change	Change - Base	Change - Base	Alt Nuclear Base	Alt Nuclear Change	Change - Base	Change - Base
	Production Cost (Billion Pounds Sterling)	Production Cost (Billion Pounds Sterling)	Diff	% Diff	Transmission Losses (TWh)	Transmission Losses (TWh)	Diff (TWh)	% Diff
2011	6.97	6.96	-0.008	-0.12%	3.82	3.57	-0.25	-6.43%
2012	7.11	7.10	-0.008	-0.11%	3.73	3.42	-0.31	-8.41%
2013	7.38	7.37	-0.006	-0.08%	3.68	3.48	-0.21	-5.57%
2014	7.69	7.68	-0.004	-0.05%	3.63	3.42	-0.20	-5.62%
2015	8.38	8.37	-0.005	-0.06%	3.40	3.22	-0.18	-5.38%
2016	8.73	8.73	-0.004	-0.05%	3.46	3.34	-0.12	-3.35%
2017	9.16	9.16	-0.001	-0.02%	3.49	3.40	-0.09	-2.50%
2018	8.54	8.54	-0.003	-0.03%	3.47	3.39	-0.09	-2.47%
2019	8.71	8.70	-0.006	-0.07%	3.74	3.65	-0.10	-2.60%
2020	8.33	8.31	-0.012	-0.15%	4.29	4.13	-0.16	-3.78%

Source: LE/Ventyx

[51] The results are on a rolling 'full year' basis, i.e., 2011 is the full year starting in April according to the BSC calendar.

6.6.2 Cost-Benefit analysis

Table 6-36 presents the total cost benefits from the introduction of P229 for the alternative nuclear development scenario. Our CBA analysis found that the total net benefit for P229 under the alternative nuclear development scenario was £223.95 million pounds. The primary benefits are from loss reductions and the largest benefits are from the emissions savings from NOx and SOx.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

Table 6-36: CBA - Alternative Nuclear Scenario with NOx and SOx (£ millions)

Year	NOx Costs	SOx Costs	Production Cost Savings	Imp. Costs	Ongoing Costs	Annual Net-Cost Benefit	Discounted Net-Cost Benefit
2011	£4.48	£10.64	£6.87	-£3.85	-£0.16	£17.98	£17.20
2012	£19.16	£37.71	£7.09	£0.00	-£0.16	£63.81	£58.41
2013	£10.83	£17.47	£6.40	£0.00	-£0.16	£34.55	£30.26
2014	£9.50	£19.16	£5.00	£0.00	-£0.16	£33.49	£28.07
2015	£12.34	£26.20	£3.72	£0.00	-£0.16	£42.10	£33.75
2016	£8.20	£15.97	£4.75	£0.00	-£0.16	£28.76	£22.06
2017	£9.56	£15.45	£1.97	£0.00	-£0.16	£26.83	£19.69
2018	£6.60	£9.53	£2.74	£0.00	-£0.16	£18.71	£13.14
2019	-£0.32	-£8.73	£5.94	£0.00	-£0.16	-£3.27	-£2.20
2020	£6.30	-£13.70	£10.62	£0.00	-£0.16	£3.07	£1.97
Totals						£266.04	£222.36
Discounted Demand Side-Benefits							£1.59
Total (including Discounted Demand-Side Benefits)							£223.95

Source: LE analysis of Ventyx Data

Table 6-37 outlines the benefits, excluding accrued benefits from NOx and SOx reduction, from the introduction of P229 for the alternative nuclear development scenario. These benefits accrue from the reductions in production costs associated with reduced losses.

The figures are in constant 2009 GBP and the discount rate used is the real after tax WACC of 4.42%.

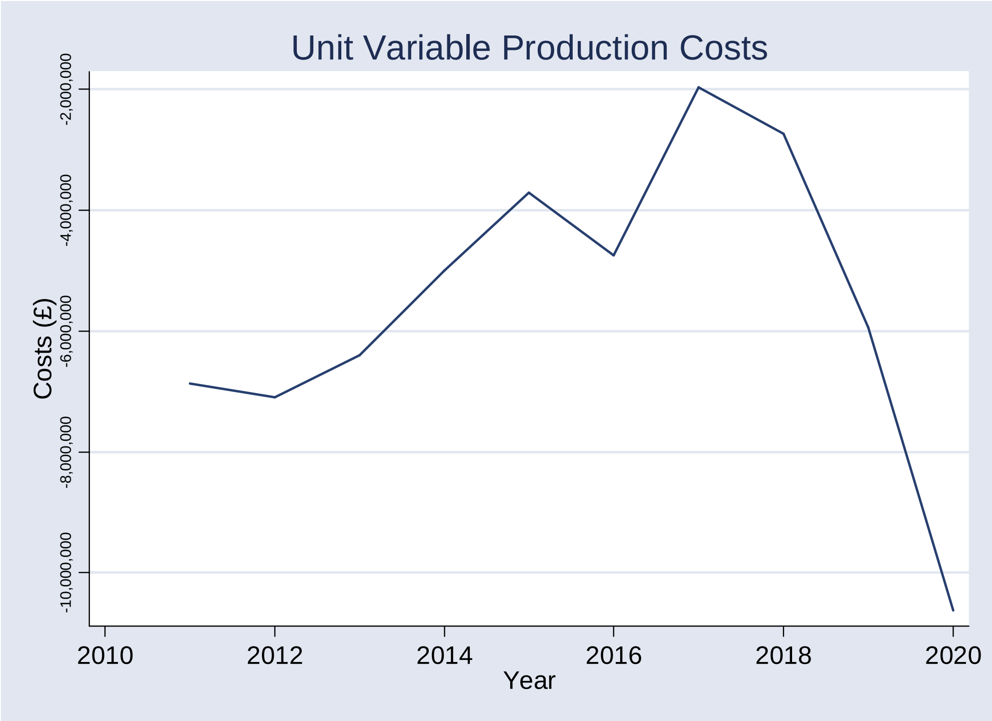
Table 6-37: CBA - Alternative Nuclear Scenario without NOx and SOx (£ millions)					
Year	**Production Cost Savings**	**Imp. Costs**	**Ongoing Costs**	**Annual Net-Cost Benefit**	**Discounted Net-Cost Benefit**
2011	£6.87	-£3.85	-£0.16	£2.87	£2.74
2012	£7.09	£0.00	-£0.16	£6.94	£6.35
2013	£6.40	£0.00	-£0.16	£6.25	£5.47
2014	£5.00	£0.00	-£0.16	£4.84	£4.06
2015	£3.72	£0.00	-£0.16	£3.56	£2.86
2016	£4.75	£0.00	-£0.16	£4.59	£3.52
2017	£1.97	£0.00	-£0.16	£1.82	£1.33
2018	£2.74	£0.00	-£0.16	£2.58	£1.81
2019	£5.94	£0.00	-£0.16	£5.79	£3.89
2020	£10.62	£0.00	-£0.16	£10.46	£6.73
Totals				**£49.70**	**£38.76**
Discounted Demand Side-Benefits					£1.59
Total (including Discounted Demand-Side Benefits)					**£40.35**
Source: LE analysis of Ventyx Data					

6.6.3 Despatch costs

The primary benefits of P229 derive from lower overall generation costs, as total system generation equals losses plus demand.

Figure 6-37 presents the difference between the base case (BAU) and the change case for the alternative nuclear development scenario. The figure shows the differences in total production costs from the modelled differences due to the introduction of seasonal and zonal TLFs. The savings are the net lowering of total generation costs, including savings from losses reductions.

Figure 6-37: Unit Variable Production Costs – Alternative Nuclear Scenario



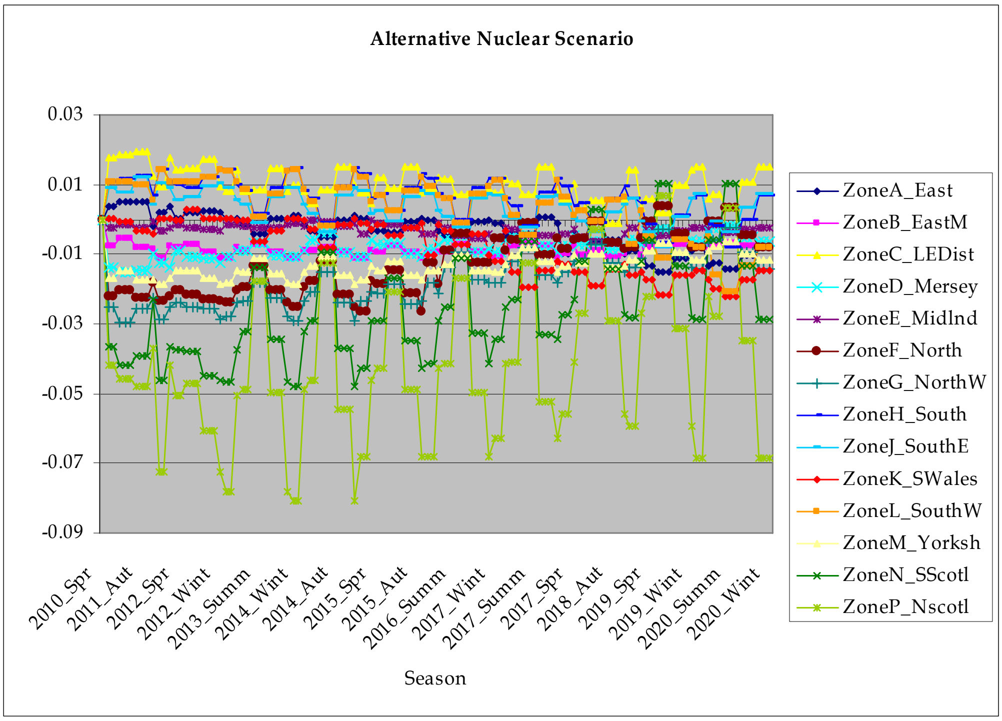
Source: LE/Ventyx

Following the first full year of implementation, production cost savings decline moderately but at an increasing rate over the years 2012 to 2015. Following this fall, there is a one period increase in 2015 followed by and sharp reduction in savings to 2017. However, following this and the introduction of the new nuclear capacity, there is an expected increase in the level of savings with savings in 2020 expected to exceed £10 million.

6.6.4 Evolved TLFs

Figure 6-38 present the evolution of TLFs, by zone, from the years 2011 to 2020 for the alternative nuclear development scenario.

Figure 6-38: Alternative Nuclear Scenario



Source: LE/Ventyx

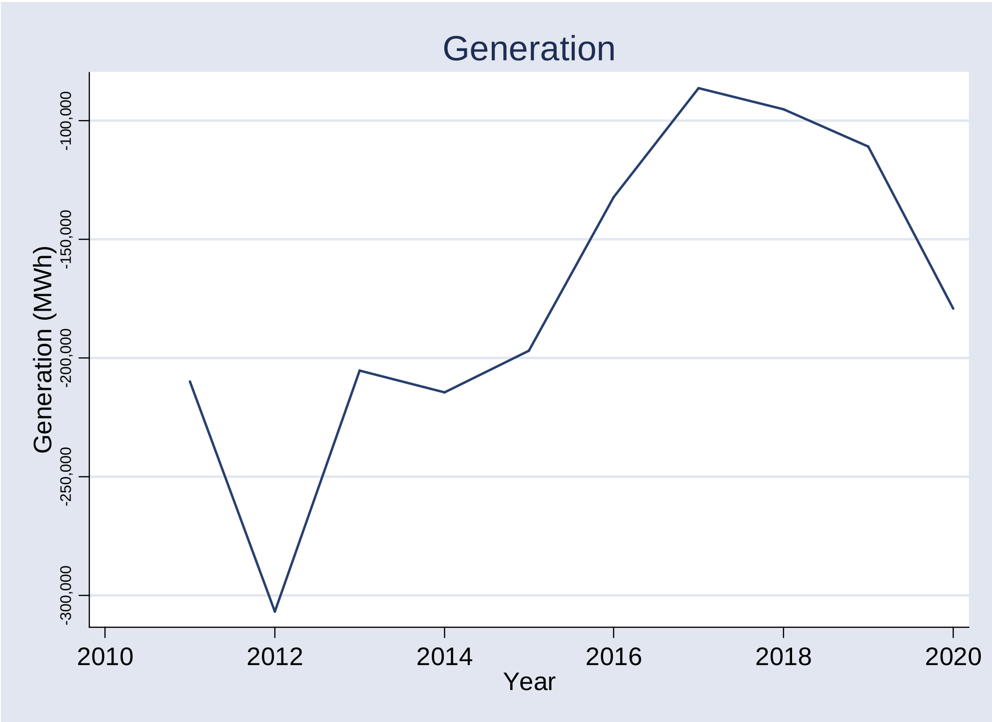
In this scenario, the analysis clearly shows that almost all of the variation is arising as a result of seasonal changes. Broadly, over the course of the modelling horizon, the levels of most zones remain within a ±0.03 band of the initial value.

The largest volatility between seasons is found in Zone P (Northern Scotland) and to a lesser extent Zone N (Southern Scotland).

6.6.5 Generation

The impact on generation from the introduction of P229, as modelled by the differences between the observed changes minus the base case, for the alternative nuclear development scenario is presented in Figure 6-39.

Figure 6-39: Generation – Alternative Nuclear Scenario



Source: LE/Ventyx

From this figure one can see there are significant generation savings in 2012, exceeding 300,000MWh. After 2012, the curve shows a sharp decline in the level of savings, until the introduction of the new nuclear capacity in 2017, after which the size and rate of savings increase.

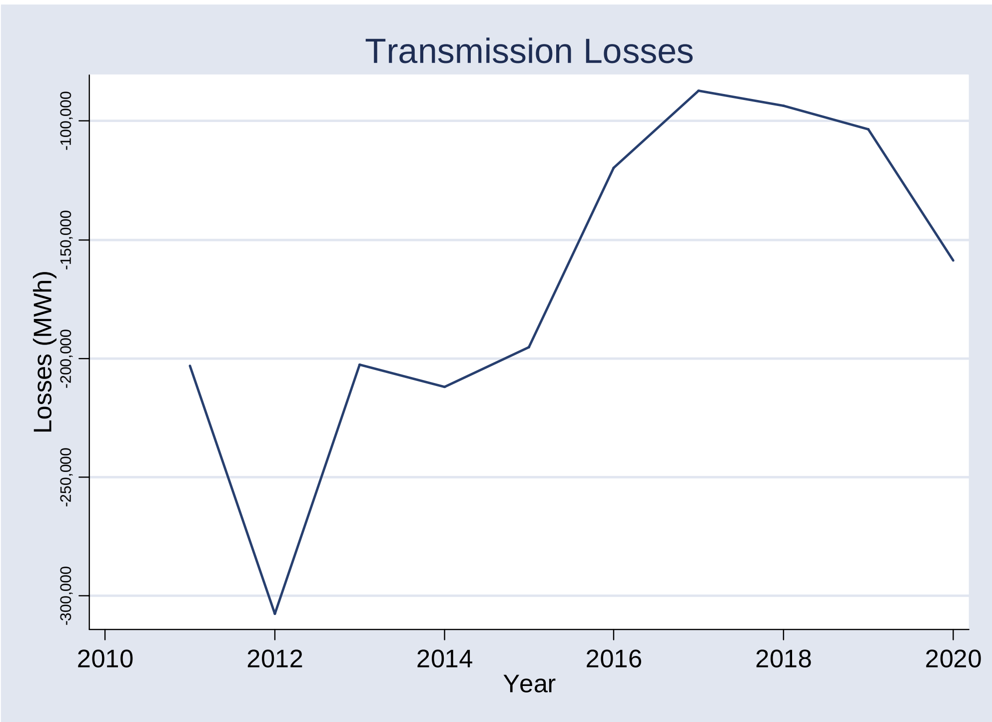
6.6.6 Losses

Figure 6-40 presents the (change case minus base case) savings in transmission system losses from the modelled introduction of P229 for the alternative nuclear development scenario.

The results show that the introduction of P229 is forecasted to lead to significantly less transmission losses in 2012, in excess of 300,000MWh per year. These savings then decline at a varying rate over subsequent years until 2017 and the introduction of the new nuclear capacity. From this point there are significant savings to be realised up to the end of the study period. The level of the savings increases over time and are in excess of 150GWh by 2020.

The pattern of loss savings largely mirrors the analysis of production cost savings. This suggests that production cost savings are being determined by loss reductions.

Figure 6-40: Transmission Losses – Alternative Nuclear Scenario

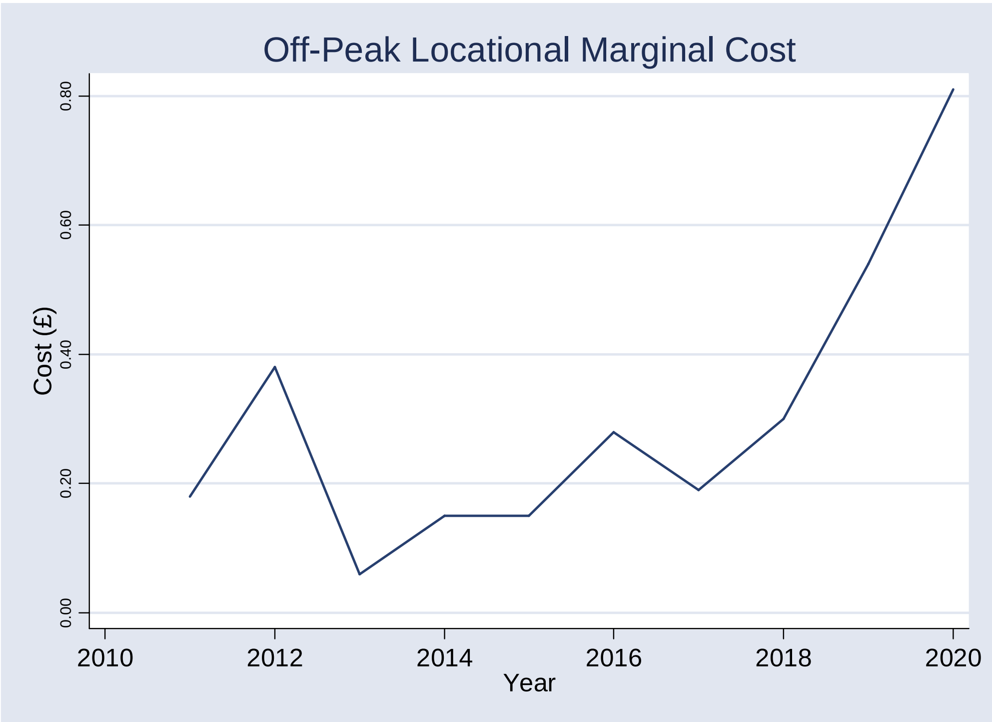


Source: LE/Ventyx

6.6.7 Wholesale prices

To show the pattern of wholesale price changes, we consider the average annual wholesale prices. We present the results for peak and off-peak price periods.

Figure 6-41: Off-Peak Locational Marginal Cost – Alternative Nuclear Scenario

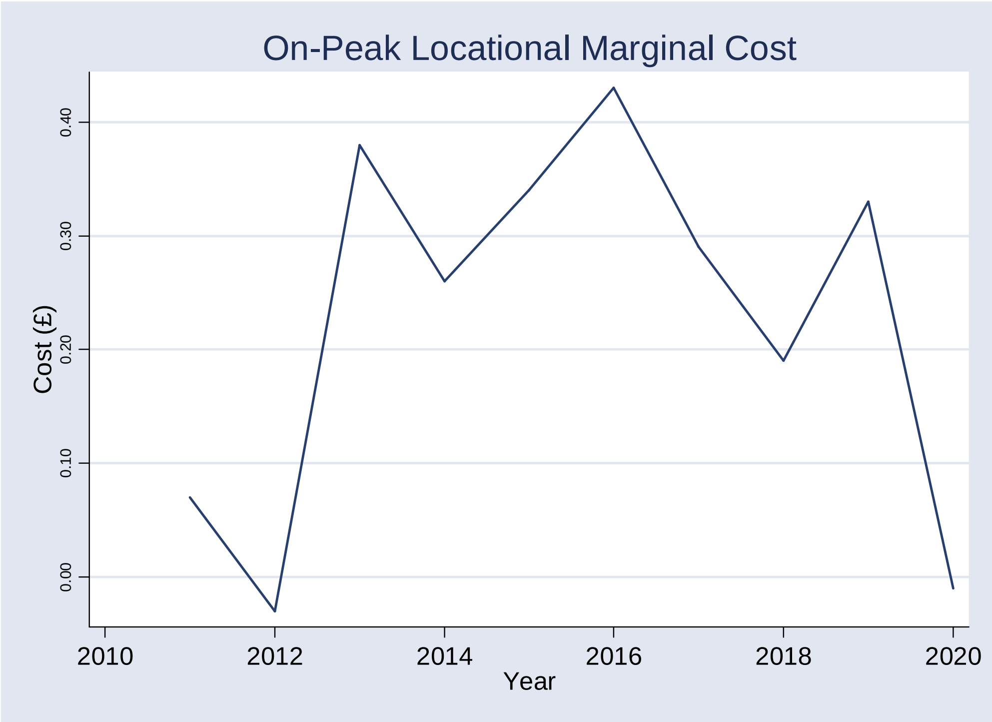


Source: LE/Ventyx

Figure 6-41 shows the difference between the competitive off-peak LMPs in the change case minus the base case for the alternative nuclear development scenario. On average, the off-peak LMPs are higher in all years under the change case from the introduction of P229. This result is as expected.

The results show a modest but overall increase in off-peak prices over the study period. In the period prior to the introduction of the new nuclear capacity, prices are between £0.06p and £0.38p higher. After 2017, there is a steady increase in off-peak prices reaching a maximum price of more than 80p in 2020.

Figure 6-42: On-Peak Locational Marginal Cost – Alternative Nuclear Scenario



Source: LE/Ventyx

Figure 6-42 presents an analogous graph of competitive on-peak LMPs differentials arising from a subtraction of the base case prices from the change prices in the alternative nuclear development scenario.

The pattern of on-peak price differences is different to that of the off-peak and throughout the study period the differences range from shifts from just under £-0.03p to £0.43p.

6.6.8 Distributional impacts in CBA from P229

Table 6-38 presents the results for the distributional impacts and potential transfers between zones for the alternative nuclear development scenario. All of the results and estimates have been calculated in the same fashion as in previous scenarios.

Table 6-38: Estimate of the distributional impacts and potential transfers – Alternative Nuclear Scenario							
Zone	**Demand (TWh)**	**Supplier TLM**	**Transfers (Supply) (£m)**	**Generation (TWh)**	**Generator TLM**	**Transfers Generator (£m)**	**Net Transfers (£m)**
North Scotland	6	0.982	4.73	2	0.969	-1.65	3.08
South Scotland	20	0.987	12.96	34	0.974	-18.12	-5.16
North West	22	0.994	9.34	18	0.981	-5.01	4.33
Northern	16	0.996	5.29	8	0.983	-1.47	3.82
Yorkshire	22	0.999	4.92	49	0.986	-4.47	0.45
Merseyside	13	1.000	2.11	16	0.987	-0.55	1.56
East Midlands	24	1.003	1.23	61	0.990	4.89	6.12
Midlands	26	1.006	-1.52	8	0.993	1.46	-0.06
South Wales	11	1.006	-0.85	19	0.993	3.99	3.14
Eastern	30	1.009	-5.13	12	0.996	3.67	-1.46
South East	18	1.012	-5.13	17	0.999	7.21	2.08
South West	16	1.012	-4.80	15	0.999	6.76	1.97
Southern	33	1.013	-10.75	7	1.000	3.15	-7.60
London	29	1.015	-12.41	0	1.002	0.13	-12.28
Source: LE/Ventyx							

The results estimate that suppliers/consumers in Scotland may receive significant benefits of approximately £18 million. Consumers in Northern England are expected to receive benefits of a further £19.6 million. These results indicate that there is likely to be a required decrease in prices among suppliers in the North of the UK.

In a similar trend to that found on the demand side, the results show the potential for considerable transfers in relation to generation. Generators in Scotland and the North of England are estimated to lose approximately £31 million while Southern generators are expected to benefit by a similar amount.

Table 6-39 presents the expected change in generation, by zone. The figures results from subtracting the base case from the change case under the alternative nuclear development scenario.

Table 6-39: Change in Generation by Zone, Alternative Nuclear Scenario (GWh)

	Year									
Zone	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Eastern	435	1,003	471	732	592	407	627	-66	-253	-72
East Midlands	-699	-1,347	-1,571	-1,584	-1,200	-939	-442	-999	619	1,289
London	105	158	227	166	204	178	158	124	77	108
Merseyside	-547	-677	-543	-64	-331	-315	-197	-187	646	1,826
Midlands	25	-9	-23	27	30	18	10	-15	-88	-364
Northern	-21	-27	-7	0	0	0	0	-104	-272	-438
North West	0	0	0	0	0	0	0	0	0	0
Southern	1,690	2,333	2,018	1,767	1,881	1,601	1,504	1,668	904	880
South East	354	1,086	649	505	518	340	293	321	-129	134
South Wales	476	805	394	203	179	40	-574	-764	-1,135	-1,604
South West	1,356	2,761	2,067	1,675	1,890	1,459	1,273	1,798	141	-1,320
Yorkshire	-2,429	-2,781	-3,007	-2,293	-2,234	-1,896	-1,132	-1,606	-810	-398
South Scotland	-937	-3,549	-788	-1,274	-1,622	-936	-1,498	-203	273	-183
North Scotland	-61	-67	-96	-67	-93	-84	-107	-52	-78	-41

Source: LE analysis of Ventyx Data

6.6.9 Impacts on the transmission system

Considering the potential impacts on the transmission system from the introduction of P229, Table 6-40 presents the percentage differences between the base case and the change case for the alternative nuclear development scenario. The data refers to the percentage change in total flows, for each year between 2011 and 2021, by voltage level.

Table 6-40: Alternative Nuclear Scenario - Change (%) in total line flows

Voltage (KV)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
132	-0.66%	-0.31%	-0.18%	-0.16%	-0.29%	-0.16%	-0.22%	-0.28%	-0.37%	-0.13%	-0.34%
275	-2.53%	-0.94%	-1.10%	-0.64%	-0.84%	-0.78%	-0.27%	-1.59%	-1.53%	-0.56%	-1.84%
400	-5.27%	-7.31%	-5.17%	-4.94%	-5.33%	-4.16%	-2.62%	-2.72%	-2.60%	-3.29%	-4.14%

Source: LE/Ventyx

For each year and level of voltage, the data shows small decreases in line flows. Again, this is consistent with the overall impact of P229, which is to reduce line losses. As in previous scenarios, flow reductions are greater for higher voltage lines.

6.6.9.1 Congestion

Table 6-41 outlines the annual number of hours with congestion, in the base case and the change case, for the years 2011 to 2020 under the alternative nuclear development scenario. As in the previous scenarios, a priori one may expect to observe and increase in congestion hours over time due to increases in load. However, under the alternative nuclear development scenario, the introduction of a significant amount of base load capacity from 2017 can be seen to reduce the total number of hours of congestion in both the base and change cases, relative to the average over the receding period.

Table 6-41: Annual Hours with Congestion - Alternative Nuclear Scenario

Year	Base	Change	Diff	Diff (%)
2011	261	174	-87	-33.33%
2012	737	641	-96	-13.03%
2013	839	769	-70	-8.34%
2014	1,207	1,084	-123	-10.19%
2015	1,546	1,434	-112	-7.24%
2016	2,257	2,143	-114	-5.05%
2017	322	305	-17	-5.28%
2018	179	163	-16	-8.94%
2019	324	307	-17	-5.25%
2020	1,220	711	-509	-41.72%

Source: LE/Ventyx

As noted previously, the alternative nuclear development scenario mirrors the reference case in the years prior to 2017. Following this point there remains relatively few differences in the total number of hours of congestion recorded by both scenarios, apart perhaps from the final year of the alternative nuclear development scenario. Within this scenario, the introduction of P229 is expected to reduce the number of hours of congestion in all years with the greatest reduction in the final year.

6.6.10 Impact on demand

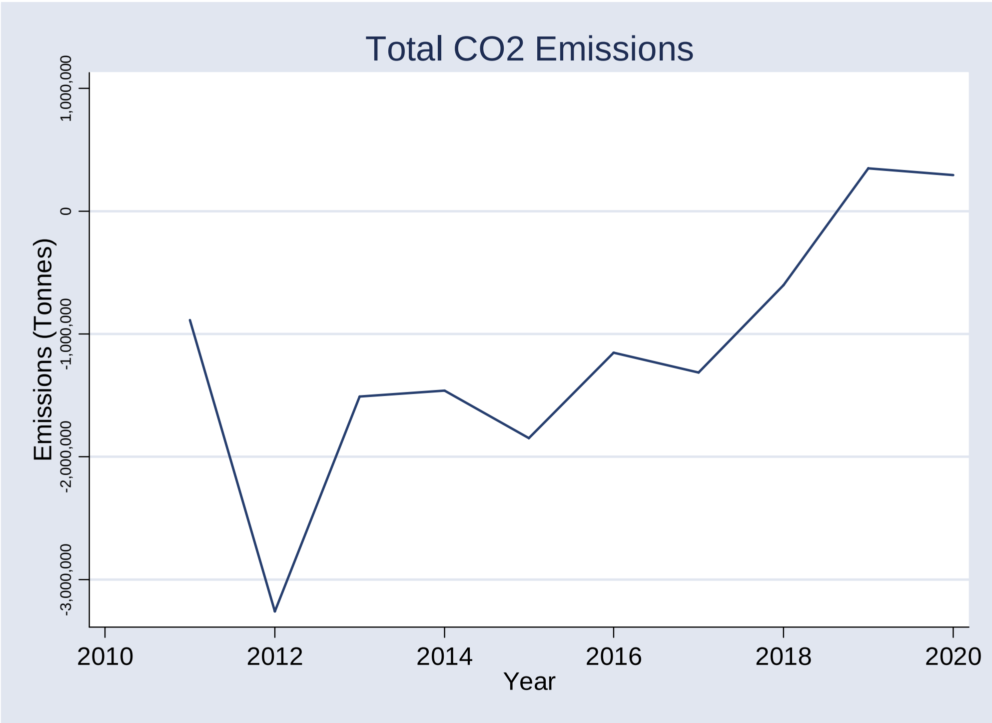
The total discounted demand-side impacts from the alternative nuclear development scenario were estimated to be £1.59m. This was calculated using the reference discount rate of 4.42%.

6.6.11 Environmental impacts emissions

6.6.11.1 CO2 emissions

Figure 6-43 presents the total change in tonnes of CO_2 emissions from the modelled alternative nuclear development scenario; the results are again the change case minus the base case.

Figure 6-43: Total CO_2 Emissions – Alternative Nuclear Scenario



Source: LE/Ventyx

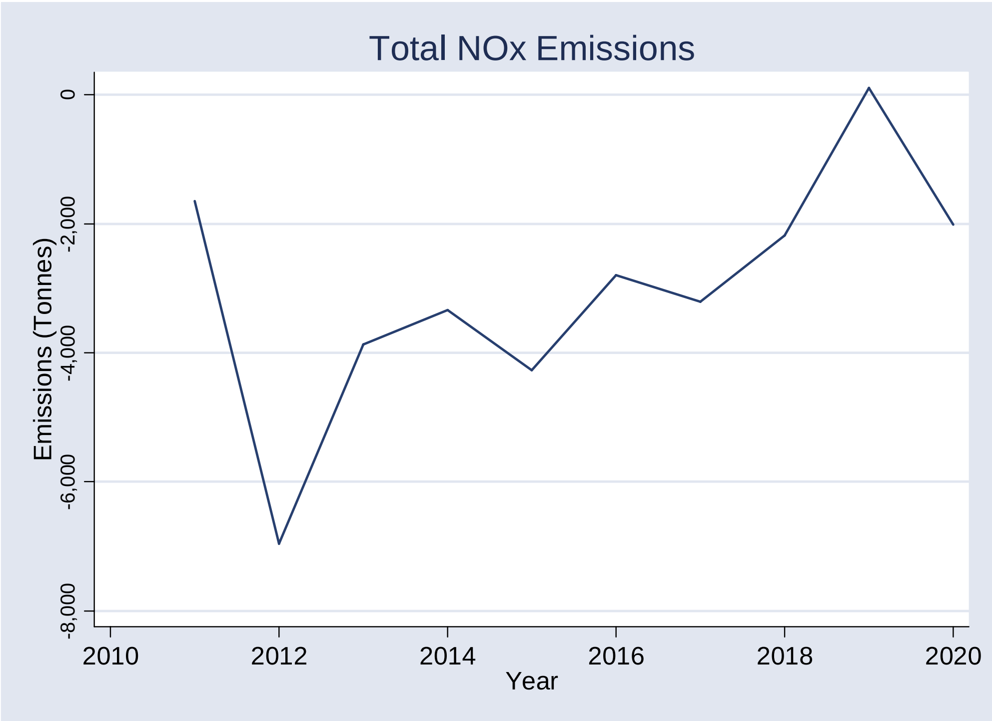
The largest relative reduction in CO_2 emissions come from the year 2012, with over 3 million tonnes being saved. There is a sharp and then gradual decline (lower levels of savings) for the remainder of the analysis. By 2019 it is expected that this value will be positive under this scenario. This result is due to the introduction of significant amount of base load nuclear capacity. Overall the level of emissions in this scenario falls significantly when compared to the reference scenario, wherein capacity expansion is primarily fossil-fuel capacity. However, what this figure is presenting is the change in emissions between the change and base case in the alternative nuclear scenario. Given the significant base load capacity expansion with zero emissions, the opportunity for reductions in overall emissions is diminished. This is the same for both NOx and SOx in the subsequent section.

6.6.11.2 SOx and NOx emissions

Emissions for sulphur and nitrogen oxides (SOx and NOx) form some of the most important emissions from the production of electric power, the primary damage from these emissions being acid rain.

The results shown in Figure 6-44 and Figure 6-45 present the change minus the base case for NOx and SOx emissions in the alternative nuclear development scenario, respectively.

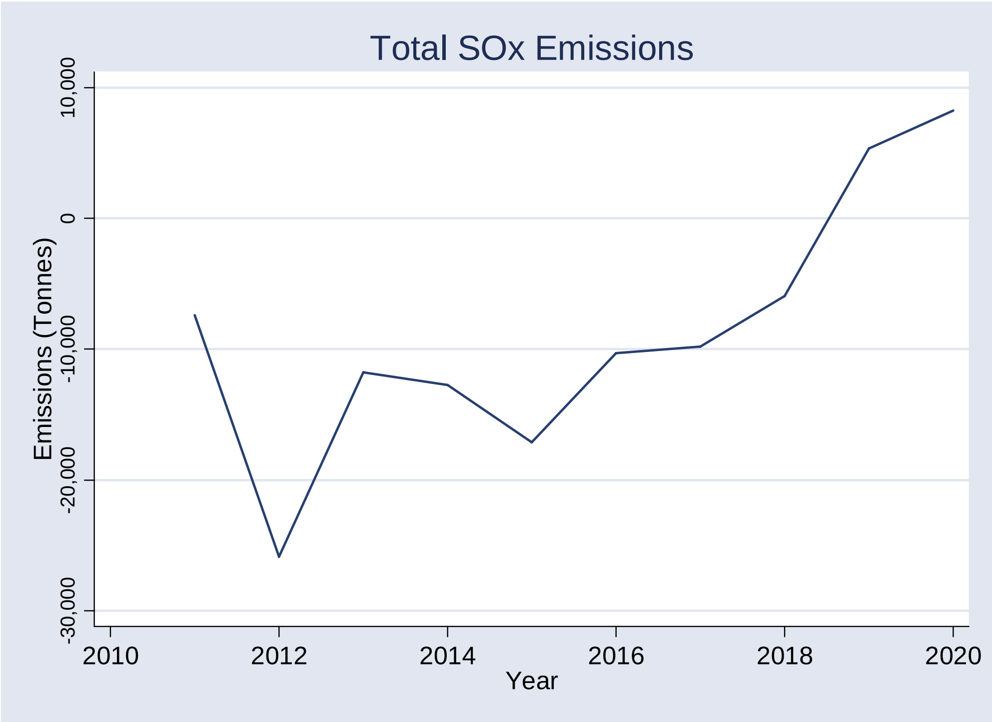
Figure 6-44: Total NOx Emissions – Alternative Nuclear Scenario



Source: LE/Ventyx

The results of our analysis on total NOx emissions show the largest savings in 2012, with almost 7,000 tonnes being saved. As with the case of total CO_2 emissions, this trend then goes from a sharp to a gradual decline in the levels of savings until 2019. In the final year of the study the level of savings increases to almost 2,000 tonnes.

Figure 6-45: Total SOx Emissions – Alternative Nuclear Scenario



Source: LE/Ventyx

As with NOx and CO_2 the largest levels of savings in SOx emissions, of approximately 25,000 tonnes, are in 2012. Again, the SOx emissions are strongly correlated with the NOx emissions but are of a differing magnitude. For example, SOx emission savings exceed NOx emission savings by a factor of 3 in almost all years.

Again, given that the SOx and NOx marginal abatement costs are £1,000 - £2,000, this will result in emissions savings values from SOx being one of the most important determinants of benefits from P229.

7 Comparison across scenarios and impact assessment

7.1 CBA comparison

As has been highlighted in previous sections of the report, there are significant differences in the relative net benefits across the 5 scenarios as a result of implementing the proposed modifications from P229. Before a comparison of scenarios can be made, however, it must be determined whether the cost of the change in emissions production should be factored into the analysis. Including the value/cost of emissions reduction into the CBA can impact on the final result by up to £230 million[52]. Table 7-1 and Table 7-2 show the respective tables for the CBA calculations, without and with NOx and SOx estimates, for each scenario.

[52] Based on a discount value of 4.42% and NOx and SOx emissions costs of £2,493 and £1,319 per tonne.

Table 7-1: Summary of CBA Values across Scenarios (without NOx and SOx impacts)

Year	Reference	High Gas	Low gas	Fuel Volatility	Aggressive Wind	Alt Nuclear
2011	£2.74	£3.69	-£1.63	£3.76	£3.25	£2.74
2012	£6.35	£11.99	£1.83	£7.03	£6.56	£6.35
2013	£5.47	£9.34	-£1.04	£2.14	£5.77	£5.47
2014	£4.06	£7.41	£0.71	£6.04	£5.63	£4.06
2015	£2.86	£3.98	£0.04	£1.45	£4.12	£2.86
2016	£3.58	£4.12	£0.55	£0.45	£3.37	£3.52
2017	£2.55	£8.81	-£0.25	£2.27	£3.15	£1.33
2018	£6.19	£12.74	£1.44	£9.87	£5.92	£1.81
2019	£5.60	£13.54	£1.76	£0.89	£7.03	£3.89
2020	£6.73	£22.13	£0.88	£12.59	£7.32	£6.73
Total	**£46.12**	**£97.77**	**£4.30**	**£46.48**	**£52.13**	**£38.76**
Discounted Loss Savings	**£1.74**	**£3.23**	**£0.36**	**£1.73**	**£1.82**	**£1.59**
Total + Discounted Loss Savings	**£47.86**	**£101.00**	**£4.66**	**£48.21**	**£53.95**	**£40.35**

Source: LE/Ventyx

As the total discounted values in the above table show, when the impact of NOx and SOx emissions are not considered, there are positive net benefits to implementing P229 across all 5 scenarios. Under the reference scenario, an estimated benefit of £47.86 million is derived from the P229 modifications, over the 2011-2020 period. The lowest benefit accruing from the proposed modifications occurs under the Low gas Price scenario, with a benefit of £4.66 million over the 10 year period. Against this, the High Gas Price Scenario provides the greatest benefit from implementing the changes in P229, with a present-value saving of £101.00 million.

With the addition of the impact of NOx and SOx estimates on generation costs, some significant changes are made to the CBA values. In scenarios with changing fuel prices (High Gas, Low Gas and Fuel Volatility), this impact is most pronounced. If the fuel price rises, it is estimated that there will be a partial switch between low emission and high emission fuels, resulting in an increase in the volume and value of emissions. The converse also holds true with a reduction in prices.

Table 7-2: Summary of CBA Values across Scenarios (with NOx and SOx impacts)

Year	Reference	High Gas	Low Gas	Fuel Volatility	Aggressive Wind	Alt Nuclear
2011	£17.20	-£1.81	£4.58	-£1.21	£19.04	£17.20
2012	£58.41	-£1.74	£19.18	£63.57	£59.03	£58.41
2013	£30.26	-£2.09	-£5.46	£26.53	£29.81	£30.26
2014	£28.07	-£4.87	£0.49	£4.14	£26.95	£28.07
2015	£33.75	-£8.79	-£0.83	£36.32	£30.86	£33.75
2016	£22.05	-£1.44	£8.59	£21.98	£20.11	£22.06
2017	£19.05	-£1.49	£7.94	-£0.81	£17.81	£19.69
2018	£22.27	£1.11	£16.36	-£3.71	£24.17	£13.14
2019	£22.73	£2.55	£13.54	£24.18	£20.54	-£2.20
2020	£21.38	-£1.39	£8.82	£1.83	£17.63	£1.97
Total excl. demand	**£275.16**	**-£19.97**	**£73.19**	**£172.82**	**£265.94**	**£222.36**
Discounted Demand Side Loss Savings	**£1.74**	**£3.23**	**£0.36**	**£1.73**	**£1.82**	**£1.59**
Total + Discounted Demand Side Loss Savings	**£276.90**	**-£16.74**	**£73.55**	**£174.55**	**£267.76**	**£223.95**

Source: LE/Ventyx

As can be seen in Table 7-2, there is a much greater variance in the aggregate CBA values with the introduction of NOx and SOx estimates. The total present-value benefit to adopting P229 rises to £276.9 million under the reference scenario (an increase of almost £230 million over the CBA without NOx and SOx values). The most noticeable change between the inclusion/exclusion of NOx and SOx is the reduction in the benefit accruing from the High Gas Scenario, down from £101.00 million to -£16.74 million.

7.2 Other variables

In addition to the overview of the Cost-Benefit Analysis by scenario, it is important to examine the effect of implementing the proposed P229 modifications across the 5 scenarios for a number of other factors. To assess the impact on the electricity generation sector, Generation, Production Cost Savings, Transmission Losses, and both On-Peak and Off-Peak Prices is discussed below. In addition, the external impacts of these changes should also be assessed. To this end, the net changes to CO_2, NOx and SOx emissions by scenario are also presented in this section.

Table 7-3: Overview of P229 Impacts

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Generation (GWh)	**Reference**	-210	-307	-205	-214	-197	-134	-138	-217	-252	-282
	High Gas	-151	-219	-214	-217	-194	-118	-155	-215	-333	-381
	Low Gas	-71	-104	-72	-112	-89	-64	-25	-69	-86	-102
	Wind	-227	-312	-207	-226	-192	-134	-147	-217	-261	-277
	Volatility	-173	-330	-151	-162	-205	-97	-94	-172	-141	-243
	Nuclear	-210	-307	-205	-214	-197	-132	-86	-95	-111	-179
Transmission Losses (GWh)	**Reference**	-203	-308	-202	-212	-195	-121	-133	-211	-245	-282
	High Gas	-157	-226	-214	-217	-194	-119	-156	-217	-329	-378
	Low Gas	-69	-101	-88	-111	-89	-61	-24	-72	-85	-103
	Wind	-220	-313	-202	-223	-183	-118	-141	-221	-264	-276
	Volatility	-175	-328	-147	-165	-201	-89	-92	-172	-136	-244
	Nuclear	-203	-308	-202	-212	-195	-120	-87	-93	-103	-159
Production Cost Savings (£million)	**Reference**	6.87	7.09	6.40	5.00	3.72	4.82	3.63	8.98	8.49	10.63
	High Gas	7.87	13.26	10.82	9.00	5.12	5.53	12.16	18.30	20.31	34.59
	Low Gas	2.31	2.15	-1.03	1.01	0.20	0.87	-0.18	2.21	2.77	1.53
	Wind	7.41	7.32	6.75	6.88	5.30	4.55	4.45	8.59	10.63	11.54
	Volatility	7.93	7.83	2.60	7.37	1.97	0.74	3.25	14.21	1.48	19.75
	Nuclear	6.87	7.09	6.40	5.00	3.72	4.75	1.97	2.74	5.94	10.62

NOx Reduction (kt)	**Reference**	1.65	6.95	3.87	3.34	4.27	2.79	3.04	2.42	2.60	2.84
	High Gas	-0.99	-2.94	-2.36	-2.32	-2.58	-0.72	-1.50	-1.99	-1.59	-3.53
	Low Gas	0.70	2.24	-0.49	-0.21	0.07	1.77	3.44	4.91	3.58	2.73
	Wind	1.80	7.00	3.67	2.96	3.73	2.68	2.79	2.69	2.17	2.20
	Volatility	-0.78	7.54	3.22	-0.21	6.02	3.66	0.07	-2.19	4.58	-1.46
	Nuclear	1.65	6.95	3.87	3.34	4.27	2.79	3.20	2.18	-0.10	2.01
SOx Reduction (kt)	**Reference**	7.41	25.86	11.79	12.73	17.13	10.23	8.50	9.69	10.74	8.40
	High Gas	-2.13	-4.73	-4.34	-5.35	-5.54	-3.30	-6.05	-6.56	-7.03	-15.44
	Low Gas	3.20	8.78	-2.49	0.22	-0.84	3.40	0.56	3.96	4.00	2.29
	Wind	8.10	26.07	11.58	11.31	14.75	8.99	7.37	11.11	8.23	5.53
	Volatility	-2.14	28.11	12.71	-1.11	17.05	11.14	-2.78	-7.91	12.61	-7.36
	Nuclear	7.41	25.86	11.79	12.73	17.13	10.28	9.79	5.94	-5.36	-8.27
CO_2 Reduction (kt)	**Reference**	885	3,257	1,511	1,458	1,848	1,153	1,205	782	948	818
	High Gas	67	-25	22	13	22	32	-151	-426	-301	-1,043
	Low Gas	590	1,071	208	321	258	479	787	845	624	470
	Wind	967	3,254	1,426	1,350	1,619	1,058	1,090	907	808	635
	Volatility	158	3,531	1,622	58	3,046	1,536	-219	-578	1,784	-556
	Nuclear	885	3,257	1,511	1,458	1,848	1,149	1,310	601	-347	-295
Off Peak LMP (£)	**Reference**	0.18	0.38	0.06	0.15	0.15	0.29	0.40	0.39	0.19	0.51
	High Gas	0.00	0.20	0.12	0.30	0.16	0.33	0.44	0.74	0.58	1.38
	Low Gas	0.21	0.12	0.03	0.18	0.15	0.22	0.21	0.17	0.25	0.22
	Wind	0.19	0.45	0.07	0.03	0.27	0.27	0.37	0.26	0.24	0.68
	Volatility	0.28	0.37	0.23	0.45	0.09	0.18	0.37	0.65	0.10	0.82
	Nuclear	0.18	0.38	0.06	0.15	0.15	0.28	0.19	0.30	0.54	0.81
On Peak LMP (£)	**Reference**	0.07	-0.03	0.38	0.26	0.34	0.44	0.23	0.27	0.25	0.24
	High Gas	0.09	0.40	0.08	-0.02	-0.01	-0.02	0.31	0.20	0.16	-0.14
	Low Gas	0.20	0.23	0.23	0.31	0.14	0.18	0.47	0.42	0.55	0.15
	Wind	0.10	0.05	0.33	0.36	0.33	0.30	0.23	0.35	0.39	0.12
	Volatility	-0.03	0.01	0.33	0.49	0.42	0.29	0.26	0.31	0.44	0.20
	Nuclear	0.07	-0.03	0.38	0.26	0.34	0.43	0.29	0.19	0.33	-0.01

Source: LE/Ventyx

Table 7-3 above shows the impact on annual values for the 8 previously listed variables across the 2011-2020 sample period, by scenario. In all cases, values refer to the estimated difference between implementing the P229 proposed modifications and retaining the current market regulations. One may note that by design, the results for the reference and alternative nuclear cases are the same until 2016, following which there is a change in portfolio of installed capacity.

7.2.1 Impacts of P229 on Generation

Table 7-4: Overview of Base/Change Case Differences: Generation

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Generation (GWh)	Reference	-210	-307	-205	-214	-197	-134	-138	-217	-252	-282
	High Gas	-151	-219	-214	-217	-194	-118	-155	-215	-333	-381
	Low Gas	-71	-104	-72	-112	-89	-64	-25	-69	-86	-102
	Wind	-227	-312	-207	-226	-192	-134	-147	-217	-261	-277
	Volatility	-173	-330	-151	-162	-205	-97	-94	-172	-141	-243
	Nuclear	-210	-307	-205	-214	-197	-132	-86	-95	-111	-179

Source: LE/Ventyx

At an annual level, implementing the proposed P229 modifications reduces generation in each year and across all scenarios, as can be seen in Table 7-4. The average (arithmetic mean across the sample years) reductions are highest in the High Gas Price Volatility Scenario, at 213.7GWh per annum on average, while the Low Gas Price Scenario experiences the lowest reductions in generation, at an average of 76.9GWh per annum.

7.2.2 Impacts of P229 on Transmission Losses

Table 7-5: Overview of Base/Change Case Differences: Transmission Losses

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Transmission Losses (GWh)	Reference	-203	-308	-202	-212	-195	-121	-133	-211	-245	-282
	High Gas	-157	-226	-214	-217	-194	-119	-156	-217	-329	-378
	Low Gas	-69	-101	-88	-111	-89	-61	-24	-72	-85	-103
	Wind	-220	-313	-202	-223	-183	-118	-141	-221	-264	-276
	Volatility	-175	-328	-147	-165	-201	-89	-92	-172	-136	-244
	Nuclear	-203	-308	-202	-212	-195	-120	-87	-93	-103	-159

Source: LE/Ventyx

As can be seen in Table 7-5, there is a strong association between the reduction in generation and the reduction in transmission losses. Across all scenarios, the reductions in transmission losses due to P229 changes account for at least 88% of the reductions in annual generation. For the Reference Scenario, the average annual reduction across the sample years in transmission losses amounts to 211.2GWh, almost 5.8% of existing grid losses. As was the case with generation, the Low Gas Price Scenario shows the lowest estimates in the average reduction in transmission losses, with an average annual decrease of 80.3GWh. Losses are reduced on average most under the High Gas price Scenario, where average annual values fall by 220.7GWh relative to retaining prevailing market regulations.

7.2.3 Impacts of P229 on Production Cost Savings

Given that the purpose of P229 is to minimise transmission losses, it is unsurprising that all 5 of the modelled scenarios show significant cost savings as a result of implementing the proposed modifications.

Table 7-6: Overview of Base/Change Case Differences: Production Cost Savings

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Production Cost Savings (£million)	Reference	6.87	7.09	6.40	5.00	3.72	4.82	3.63	8.98	8.49	10.63
	High Gas	7.87	13.26	10.82	9.00	5.12	5.53	12.16	18.30	20.31	34.59
	Low Gas	2.31	2.15	-1.03	1.01	0.20	0.87	-0.18	2.21	2.77	1.53
	Wind	7.41	7.32	6.75	6.88	5.30	4.55	4.45	8.59	10.63	11.54
	Volatility	7.93	7.83	2.60	7.37	1.97	0.74	3.25	14.21	1.48	19.75
	Nuclear	6.87	7.09	6.40	5.00	3.72	4.75	1.97	2.74	5.94	10.62

Source: LE/Ventyx

As Table 7-6 indicates, with just two exceptions, there are positive net production cost savings in every year of each scenario. The table above shows the total annual net present value of savings. Totals in net present value savings (the sum across all the years) range from £11.7 million in the Low Gas Scenario, to £137.0 million in the High Gas Scenario. Average annual production cost savings over the 2011-2020 period across all scenario are estimated at £71 million. The average NPV across scenarios was £6.8m.

7.2.4 Impacts of P229 on NOx Reductions

In addition to the cost savings attributable to a reduction in generation, there are also positive social benefits to decreasing the transmission losses from electricity generation. Table 7-7 below shows the reduction in kilotonnes of NOx per annum.

Table 7-7: Overview of Base/Change Case Differences: NOx Reductions

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
NOx Reduction (kt)	Reference	1.65	6.95	3.87	3.34	4.27	2.79	3.04	2.42	2.60	2.84
	High Gas	-0.99	-2.94	-2.36	-2.32	-2.58	-0.72	-1.50	-1.99	-1.59	-3.53
	Low Gas	0.70	2.24	-0.49	-0.21	0.07	1.77	3.44	4.91	3.58	2.73
	Wind	1.80	7.00	3.67	2.96	3.73	2.68	2.79	2.69	2.17	2.20
	Volatility	-0.78	7.54	3.22	-0.21	6.02	3.66	0.07	-2.19	4.58	-1.46
	Nuclear	1.65	6.95	3.87	3.34	4.27	2.79	3.20	2.18	-0.10	2.01

Source: LE/Ventyx

With the exception of the High Gas Scenario (where NOx emissions rise by 2.1 kilo-tonnes per annum), NOx emissions are, in general, reduced as a result of the introduction of P229. Under the reference scenario, NOx emissions levels fall by an annual average of 3.4 kilotonnes. Using estimates of Best Available Technology Emissions Control Technology (BATECT), the cost of reducing this level of emissions is estimated at £76.04 million[53]. The average annual reductions across the remaining scenarios, High Gas, Low Gas, Wind, Volatility, Nuclear, are: -2.05, 1.87, 3.17, 2.05, 3.02 kilotonnes.

[53] Based on estimates from Barrett, M., "The Costs And Health Benefits Of Applying Reducing Emissions From Power Stations In Europe", for the Swedish NGO Secretariat on Acid Rain, November 2007

7.2.5 Impacts of P229 on SOx Reductions

Table 7-8: Overview of Base/Change Case Differences: SOx Reductions

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
SOx Reduction (kt)	Reference	7.41	25.86	11.79	12.73	17.13	10.23	8.50	9.69	10.74	8.40
	High Gas	-2.13	-4.73	-4.34	-5.35	-5.54	-3.30	-6.05	-6.56	-7.03	-15.44
	Low Gas	3.20	8.78	-2.49	0.22	-0.84	3.40	0.56	3.96	4.00	2.29
	Wind	8.10	26.07	11.58	11.31	14.75	8.99	7.37	11.11	8.23	5.53
	Volatility	-2.14	28.11	12.71	-1.11	17.05	11.14	-2.78	-7.91	12.61	-7.36
	Nuclear	7.41	25.86	11.79	12.73	17.13	10.28	9.79	5.94	-5.36	-8.27

Source: LE/Ventyx

Similar to the effect on NOx emissions, average annual reductions in SOx emissions are observed across all but one of the scenarios. The average annual reductions for each of the scenarios, Reference, High Gas, Low Gas, Wind, Volatility, Nuclear, are: 12.25, -6.05, 2.31, 11.30, 6.03, 8.73, kilotonnes. The average (arithmetic mean) reduction level across all scenarios estimated at 5.7 kilotonnes per annum. The most significant single year impact is observed in the Reference and Wind Scenarios, where total reductions of 122.47 kilotonnes and 113.05 kilotonnes are predicted. Using BATECT reduction costs, the cost of controlling these emissions would amount to £152.96 million and £141.19 million respectively.

7.2.6 Impacts of P229 on CO_2 Reductions

Table 7-9: Overview of Base/Change Case Differences: CO_2 Reductions

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
CO2 Reduction (kt)	Reference	885	3,257	1,511	1,458	1,848	1,153	1,205	782	948	818
	High Gas	67	-25	22	13	22	32	-151	-426	-301	-1,043
	Low Gas	590	1,071	208	321	258	479	787	845	624	470
	Wind	967	3,254	1,426	1,350	1,619	1,058	1,090	907	808	635
	Volatility	158	3,531	1,622	58	3,046	1,536	-219	-578	1,784	-556
	Nuclear	885	3,257	1,511	1,458	1,848	1,149	1,310	601	-347	-295

Source: LE/Ventyx

The estimated impact on the reduction in CO_2 emissions as a result of the proposed P229 modifications retains the trend observed in NOx and SOx estimates, with all scenarios bar "High Gas Price" showing significant reductions in annual levels. Under the Reference Scenario, values are predicted to fall by a total of 13,865 kilotonnes, representing a 0.97% reduction in total estimated CO_2 emissions, based on current market regulation.

7.2.7 Impacts of P229 on Off-Peak Prices

The final set of variables to be analysed in this section are Off-Peak and On-Peak Prices. Estimates of the change in off-peak prices across all scenarios are show in Table 7-10

Table 7-10: Overview of Base/Change Case Differences: Off-Peak LMP

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Off Peak LMP (£)	Reference	0.18	0.38	0.06	0.15	0.15	0.29	0.40	0.39	0.19	0.51
	High Gas	0.00	0.20	0.12	0.30	0.16	0.33	0.44	0.74	0.58	1.38
	Low Gas	0.21	0.12	0.03	0.18	0.15	0.22	0.21	0.17	0.25	0.22
	Wind	0.19	0.45	0.07	0.03	0.27	0.27	0.37	0.26	0.24	0.68
	Volatility	0.28	0.37	0.23	0.45	0.09	0.18	0.37	0.65	0.10	0.82
	Nuclear	0.18	0.38	0.06	0.15	0.15	0.28	0.19	0.30	0.54	0.81

Source: LE/Ventyx

The greatest change in Off-Peak prices occurs under the High Gas Price Scenario, with increases estimated at £0.47 per MWh. The average increase across all scenarios is predicted to be £0.30 per MWh, representing an increase of 0.80% in baseline prices.

7.2.8 Impacts of P229 on On-Peak Prices

The impact on on-peak prices from implementing the P229 changes is similar to the effect on off-peak prices, but differs in the magnitude of the effect. The greatest change is observed in the Low Gas Price Scenario, with prices increasing by an annual average of £0.29 per MWh. The average increase across all scenarios is predicted to be £0.23 per MWh (£0.07 lower that the comparative on-peak price change), representing an increase of 0.57% in baseline prices. Table 7-11 below shows the annual trends in on-peak prices across all scenarios.

Table 7-11: Overview of Base/Change Case Differences: On-Peak LMP

		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
On Peak LMP (£)	Reference	0.07	-0.03	0.38	0.26	0.34	0.44	0.23	0.27	0.25	0.24
	High Gas	0.09	0.40	0.08	-0.02	-0.01	-0.02	0.31	0.20	0.16	-0.14
	Low Gas	0.20	0.23	0.23	0.31	0.14	0.18	0.47	0.42	0.55	0.15
	Wind	0.10	0.05	0.33	0.36	0.33	0.30	0.23	0.35	0.39	0.12
	Volatility	-0.03	0.01	0.33	0.49	0.42	0.29	0.26	0.31	0.44	0.20
	Nuclear	0.07	-0.03	0.38	0.26	0.34	0.43	0.29	0.19	0.33	-0.01

Source: LE/Ventyx

7.3 Impacts on Demand

We have estimated the impacts on demand using the TLFs for the full period. Overall, the impacts on demand are expected to be small, but perhaps not insignificant. One would expect incentives to locate/relocate demand from high loss charge zones (Southern and London for demand) to low loss charge zones (Northern) would result in some small changes in consumption via power price changes.

In addition, the demand-side estimates, while as robust as possible using the available data, time and resources, are in our opinion subject to more uncertainty than some of our other estimates. This is because detailed elasticity estimation was not possible as it would have required collecting locational (i.e., by zone) and time-series data on demand levels and drivers (e.g., domestic versus industrial and commercial, population, GDP, income across GSP zones, business types by location, weather/seasonal variables by zone). There also could be more in depth investigation of time-lags for demand-side response. Deeper estimation of these factors was not possible within the time and budget of the project[54]. What was done was to apply aggregate elasticity numbers to aggregate demand within the zone. (In other words, a single elasticity number was applied to zonal price changes to generate quantity demanded changes in all zones).

7.4 Other impacts

One of the more significant impacts of P229 is its potential to reduce emissions. This occurs through a number of ways; reductions in overall generation and demand; reductions in losses; incentives to shift generation across zones.

There is also some concern of how P229 might impact on environmental variables in secondary ways. For example, it might give different incentives for renewables generation, perhaps the implicit assumption being that some types of renewables would be more likely to locate in certain regions (e.g., wind in the west/northwest, hydro in Scotland, embedded generation more likely to be renewables, etc).

[54] We note that a similar approach was used in previous proposals.

7.4.1 Environmental impacts and renewables generation

It is our opinion that, in general, P229 is not predicted to have any discernable impact on renewables, and especially the capacity/energy of renewables going forward. There are a number of reasons for this conclusion. First, it cannot be assumed with any real certainty that any one region is that much 'better' for renewables. So for example, while it is true that the North and west and Scotland have better wind speeds, more available sites for hydro, etc, the site location and the available ambient conditions for power generation are often highly site-specific and idiosyncratic. Currently, large scale offshore wind is going in the Southeast as well as other locations.

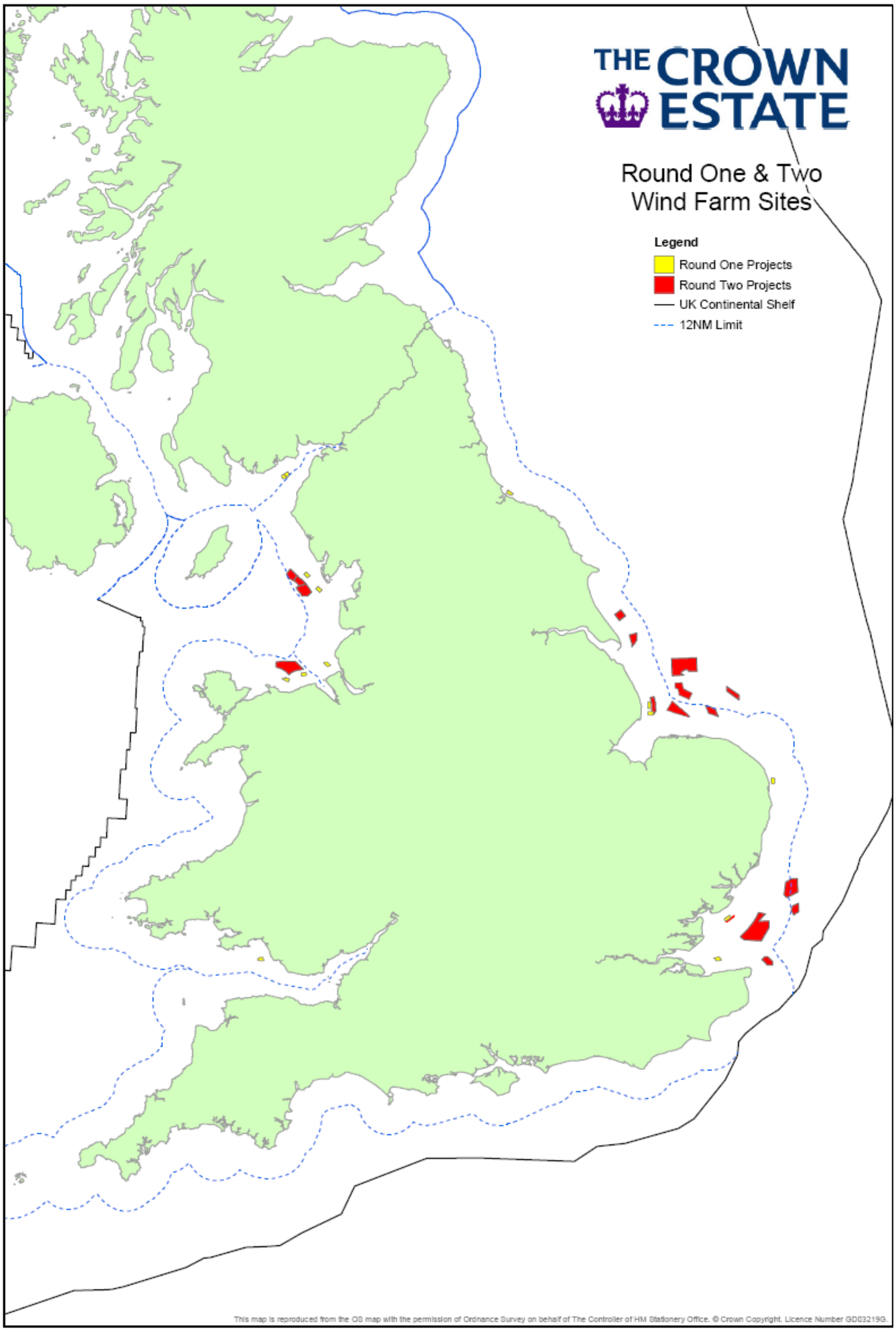
According to data from the Crown Estates, there are more offshore wind projects planned under the Round 1 and 2 schemes for the East and Southeast, than the North and west. Additional sites at Lynn and Inner Dowsing are under construction, and a count shows a total of 17 sites operational or under construction offshore in the East and 10 sites in the west; zero in northern Scotland. According to data on offshore projects under planning from the BWEA, a total of 4 projects are planned for the east, while 3 are planned for the west, with one project planned for northwest Scotland (Bettyhill).

Further, given the analysis comparing TNUoS charges with TLF zonal charges, it is apparent that other concerns, such as land, other charges, other factors, will have a more important impact on locational decisions for generators than will TLFs.

We do not believe that there will be any predictable, measurable, or significant impact from P229 on fuel transportation costs for generation from generation plants moving location as a result of locational signals produced from P229.

The figure below shows the Crown Estate data on current R1 and R2 offshore wind farms.

Figure 7-1: Round 1 & 2 Wind Farm Sites



Source: The Crown Estate (website)

It should also be reiterated that there are additional environmental benefits expected from P229, as we have only quantified the main emissions reductions. These impacts include: soot, ash and particulates; heavy metals such as mercury; the smog impacts of SOx and NOx and other emissions. Since the overall impact of P229 is predicted to reduce losses, this would overall reduce emissions of all types.

7.4.2 Embedded generation

Embedded generation is, in general, generation that is connected to the distribution system rather than the transmissions system. As such, it is naturally more likely to be small scale generation. Embedded generation is often more likely to involve renewables, including small wind, small scale hydro, biomass, and small CHP. It is expected that embedded generation will be increasing over the next decade.

One of the benefits of embedded generation is that it reduces line losses (potentially at the transmission and distribution level). The direction of the impact on transmission losses mostly depends on the location of the embedded generation (i.e., if it would tend to reduce demand in a zone, where that is beneficial to the transmission system in terms of reducing losses).

Direct modelling of embedded generation was not possible from this project, as we only received data from the transmission side of the GB electricity system. In other words, the demand data received was all net demand delivered from the transmission system to distribution systems.

Implicitly, however, embedded generation was modelled, to the extent that the current pattern of demand and existing embedded generation is already reflected in the current demand data. Further, our demand forecasts are for total demand net of embedded generation.

In order for P229 to have discernable and significant impacts on embedded generation, we would expect this to require: a) a pattern of embedded generation in zones that will have significant TLF changes, and b) the ability and likelihood of future embedded generation to respond. It is very difficult to say if these conditions would be met. If anything, we might posit the assumption that embedded generation would be more likely to locate in large demand zones (e.g., South and more populous areas) or in zones where transmission connections tend to be further away (Northern and more rural). This suggests it an ambiguous, if any, impact on embedded generation.

7.4.3 132kV generation

Generation at lower voltage but that is connected to the transmission system will be treated in the same way as any other voltage connected. Therefore, one would not expect a difference in impact on those generators connected to the 132kV element of the transmission system, when compared to geographically proximate[55] generators connected at higher voltages. We also note the analysis of line flow changes by voltage levels, which showed the major changes in flows by voltage are predicted to occur on the higher voltage lines.

7.4.4 Import/export via the interconnector

We have not modelled import and export over the interconnectors explicitly. The main drivers of import/export are the cost of power on either side of the interconnector and the cost/availability of capacity on the interconnector, along with other constraints. The impacts of P229 are very small price impacts. It is not likely that these price differentials are going to be larger than price differential that arise between countries. In addition, since a single price cannot be said to hold across the Northwest EU power interconnection, it can be reasonably assumed that significant barriers to trade over the interconnectors already exist (i.e., since price differentials have tended to persist).

[55] (we assume this means within the same zone)

7.4.5 Impact on capacity requirements

It is difficult to say precisely what the impact on capacity requirements within the system would be. On the whole, it should be noted that since total line losses should be reduced, this is akin to having additional generation and additional capacity at certain times. However, it should be noted that the total line losses are a small percentage of the total production (and a smaller percentage of available capacity). Further, it cannot be said with 100% certainty that this is the case as capacity only becomes an issue at system peak times or in times of rare events, the later of which would be very difficult to model in a meaningful way. It should be noted that our proposed solution did not include a full study of available capacity in the GB system at times of system peak or rare events and data on this was not known to be available. Therefore, we would predict a likely small and positive but somewhat insignificant impact on capacity requirements.

7.4.6 Cost of carbon emissions

The total cost of carbon emissions depends on the price of carbon, the quantity of carbon, and the quantity of carbon allowances issued to the power sector. The overall quantity of carbon emissions is predicted to fall, as losses reductions reduce total fuel burn.

While one of the impacts of P229 will be to reduce the "quantity" of carbon emissions, there is also the possibility, at least in theory, that it could impact the price of carbon emissions, and this point is mentioned in the P229 original terms of reference ("impact on the cost of carbon emissions to generators").

It is our expert opinion that P229 will have no discernible or estimable impact on the price of carbon. First, it should be noted that the EU ETS trading scheme is a pan-EU system covering many countries, sectors, and emissions that are far in excess of the power sectors emissions (let along just the bulk power system in GB). EU ETS currently covers over 11.500 energy-intensive installations across the EU, which represent close to half of Europe's emissions of CO_2. These installations include electric power and other combustion plants, oil refineries, coke ovens, iron and steel plants, and factories making cement, glass, lime, brick, ceramics, pulp and paper (and possibly aviation in the future). Secondly, the overall changes in MWh and emissions are quite small relative to the whole EU ETS sector. In previous work, we have built an all EU trading model of carbon emissions based on Eurostat and other EU ETS data. The model estimated marginal abatement cost functions and then solved the cost minimisation problem assuming quadratic abatement costs, with shift factors for each sector and each country. Casual inspection of the model confirms that a 1-4million tonne *reduction* per annum in C02 emissions (roughly the size of the changes per annum from P229) would have no significant impact on the price of carbon in EU ETS. It should be noted that there are roughly 2.1 billion tonnes of EU ETS allowances per annum.

Finally, it would be difficult to say if P229 (either adopting it, or not) would have any impact on the quantity of allowances allowed under the next round of EU ETS. It could be hypothesized that the next plan might seek to induce greater emissions savings, but whether P229 would have any impact on that is probably too uncertain to say.

On the whole then, since there will be no price impacts, the cost of carbon emissions to the generators in sector is predicted to fall, to the extent that generators have some shortfall in their carbon emissions allowances and given the fact that overall emissions are predicted to be reduced.

7.4.7 Impact on location of new generation plant

The introduction of a zonal loss regime may affect generators' locational decisions in relation to where to develop new generation capacity (also exit and mothballing decisions). Of the quantifiable factors affecting a generators locational decision, transmission system charges (TNUoS – Transmission System Use of System), fuel transportation charges and zonal loss charges are likely to be important to the financial returns from locating a generation asset at a specific location. To assess the impact of each of these factors, a comparative analysis of the related charges associated with locating a hypothetical 400MW CCGT unit in selected regions in the UK has been undertaken.

For NTS connected units buying gas at the NBP the only charge that varies on a region basis is the NTS exit charge. The charge relating to a hypothetical 400MW CCGT unit with an assumed efficiency of 55% and an assumed load factor of 85% is calculated using the average pence/peak day/kWh per day value reported by the NGC for the DN exit points in each of the relevant regions.

The TNUoS charges are charges levied on generators for use of the transmission system. Using the most recently publicised data from the NGC (2009/10), an estimate of the transmission costs of a 400MW CCGT unit with an 85% load factor were calculated. TNUoS charges are unrelated to loss charges but one would expect the two to be positively correlated.

The zonal loss charges are based on zonal TLMs derived from the modelled generation and TLFs arising from a system operating under the proposed regime. The competitive price of electricity is assumed to be the weighted average annual price in 2011 taken from the modelling of the proposed change, £37.66/MWh.

The selected regions were selected to represent a diverse mix of locations and are as follows:

- South East
- South West
- London
- North East
- South Scotland
- North Scotland

Table 7-12 presents a comparison of these costs allowing one to assess their relative importance in the locational decision process of generators and how this is likely to be altered by the introduction of P229. Of the three costs, the exit charges are likely to be the smallest in relation to locating a hypothetical 400MW CCGT unit in one of these regions. Due to the structure of the gas network and the entry points into the system, these charges are relatively low in Scotland and the North of England but increase as one considers locations in the South and particularly South West of England. Overall, the differential in these costs remains relatively small for such a hypothetical unit at just £1.33 million.

The costs relating to transmission system charges and transmission losses follow a similar pattern and are typically inversely correlated with exit charges. From the table one can see that although zonal loss charges exhibit higher overall costs and a greater differential between zones than do the exit charges, the TNUoS charges are likely to be the greatest factor of the three driving the locational decisions of generators. A differential in costs of over £5.8 million per annum is significantly greater than the cost differential of both Exit charges and zonal loss charges combined. Therefore, the introduction of P229 is not expected to lead to a change in the locational decisions of generators favouring Southern regions due primarily to TNUoS charges.

Table 7-12: Comparison of costs relating to location of new capacity

Hypothetical CCGT plant	GSP Group	Generation Tariff Zone	NTS Exit Charge	TNUoS Charge	Regional Comparison (before zonal-seasonal loss charging)	Zonal-seasonal loss charging Payments	Regional Comparison (after zonal-seasonal loss charging)
					£ millions		
North East	NE	10	0.105	3.941	4.046	1.74	5.78
London	NT	16	0.827	-2.791	-1.964	-0.25	-2.21
North Scotland	SC	1	0.007	8.635	8.643	2.92	11.56
South Scotland	SC	7	0.007	5.441	5.448	2.57	8.02
South East	SE	17	0.983	0.102	1.085	0.21	1.29
South West	SW	19	1.336	-1.313	0.023	0.16	0.18

Source: LE/Ventyx

8 Conclusions

This report by London Economics and Ventyx (LE/Ventyx) estimates the costs and benefits for modification proposal 229 for Elexon. The proposed change involves changing the current system of charging for variable transmission losses, where transmission losses are charged to transmission system users geographically averaged and annualized basis, to a zonal and seasonal basis.

We conclude that the net benefits of P229 are predicted to be positive and significant on a net present value basis. The main benefit comes from production cost savings, reduced fuel consumption by power generators, which are the net fuel savings from the reduction in transmission line losses and changes to the despatch. For the reference scenario, the overall net discounted benefit, including CO_2 emissions reductions is predicted to be £47.86m.

An element of P229 that extended further previous analysis was explicit modelling and consideration of environmental benefits. Besides CO2 emissions reductions, major polluting emissions such as SOx and NOx are predicted to be reduced. Including the value of SOx and NOx reductions in the CBA yields much larger net benefits from P229. Including these emissions reductions values in the CBA for the reference scenario would give an overall NPV of the net benefit of £276.9. Since the SOx and NOx per unit reduction benefits are not priced as is the case with CO2 via EU ETS prices, we have used a marginal abatement cost estimate to price these emissions. While there is some additional uncertainty as to the value of the SOx and NOx via the use of the abatement cost to price the emission reductions, these estimates are conservative in that the "social value" of emissions reductions might be substantially higher.

A summary of the impacts predicted from the introduction of P229 are found in the table below.

Table 8-1: Overview of P229 Impacts - Reference Scenario Savings (Change Case – Base Case)											
		Year									
	Scenario	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Generation (GWh)	Reference	-210	-307	-205	-214	-197	-134	-138	-217	-252	-282
Transmission Losses (GWh)	Reference	-203	-308	-202	-212	-195	-121	-133	-211	-245	-282
Production Cost Savings (£million)	Reference	6.87	7.09	6.40	5.00	3.72	4.82	3.63	8.98	8.49	10.63
NOx Reduction (kt)	Reference	1.65	6.95	3.87	3.34	4.27	2.79	3.04	2.42	2.60	2.84
SOx Reduction (kt)	Reference	7.41	25.86	11.79	12.73	17.13	10.23	8.50	9.69	10.74	8.40
CO2 Reduction (kt)	Reference	885	3,257	1,511	1,458	1,848	1,153	1,205	782	948	818
Off Peak LMP (£)	Reference	0.18	0.38	0.06	0.15	0.15	0.29	0.40	0.39	0.19	0.51
On Peak LMP (£)	Reference	0.07	-0.03	0.38	0.26	0.34	0.44	0.23	0.27	0.25	0.24
%Change in Line Flow 400kV	Reference	-5.27%	-7.31%	-5.17%	-4.94%	-5.33%	-4.16%	-3.58%	-5.34%	-6.13%	-6.95%

*Source: **LE/Ventyx***

The table shows that P229 is expected to have a wide range of benefits across a range of different parameters from the reference scenario.

The distributional impacts of P229 are, in monetary terms, significantly larger than the overall net benefits. The predicted total value of generation transfers in the reference case, for example, goes up to £15.27m in South Scotland. The monetary value of distributional impacts, however, cannot be compared with the CBA values, as the appropriate "weighting" of distributional changes must be defined/judged by the policy maker. Further, there is additional uncertainty as to the distributional impacts since i) some companies have demand and generation in the same region/zones ii) some companies may have operations in multiple zones, iii) the extent to which cost increases can be passed on to final consumers may impact the overall distributional impacts of P229. It should be noted that the overall estimated distributional impact on suppliers is expected to be small. Since supply is close to a perfectly competitive business, and since demand changes in response to prices are very small in the short run, and small in the long run, then any additional costs to supply a customer in any particular zone would be passed on to consumers, as a supplier from another lower cost zone cannot come in and offer a lower cost electricity product—the zonal TLF charge will be payable by the location of the demand.

The impact of P229 on demand and on the demand side is expected to be small but positive, but beneficial to the transmission system, to line losses, to capacity needs and to emissions reductions, as the overall effect is expected to incentivise more efficient use of the transmissions system by demanders, in the same way P229 works for generators. There is significant uncertainty around the demand impact estimates, as precise elasticity estimates were not available. Nonetheless, a large body of evidence suggests aggregate elasticities are small but significantly different from zero.

The overall net impact on wholesale prices is expected to be small. As a measure of this, we predict that the system marginal cost (or competitive price) is expected to rise by about 0.59% for peak prices and by 0.71%p for offpeak prices. It should be noted that the total impact on wholesale prices should be a function of redespatch costs and net marginal cost reductions for system marginal generators (price setting) due to both TLF, line loss reductions, and redespatch costs. It should also be noted that any degree of less than perfectly competitive behaviour by generators could be expected to mitigate this effect.

The overall impact of P229 is expected to be beneficial to the transmission system in terms of reducing overall levels of line flows and capacity needs, with potential impacts on reduced congestion. Average line flow reductions are predicted to be most significant at the 400kV level.

P229 is not expected to have significant or measurable impacts on plant entry, exit or mothballing. Analysis showed that other locational charges and location-specific concerns form the majority of costs and concerns for plant locational decisions, and that P229 is not likely to re-order plant location decisions. In addition, most new entry or exit that might occur during the period is already scheduled, planned or under construction with major locational decisions already made. For plants that have already been sited, it is unlikely that they would have changed their decision, if P229 had been in place when they had made their locational decisions. Finally, TNUoS charges give a non-variable locational incentive to generators, and these, while substantially larger than the financial impact of the proposed TLFs have had seemingly little impact on changing overall plant location decisions.

Our study undertook six scenarios, five in addition to the 'reference' scenario, to assess the sensitivity of the conclusions to changes in the most important input forecasts. We should note that the reference case is believed to be the most probable or central scenario. The scenarios chosen were developed using inputs and suggestions from Elexon and the P229 Modification Group. The sensitivities included: high gas prices, low gas prices, volatile fuel price, aggressive offshore wind, and an alternative development of nuclear assets.

The total net CBA for each of the five scenarios was: £47.86, £101.00m, £4.66m, £48.21m, £53.95m, £40.35m, for the reference, high gas prices, low gas prices, fuel volatility, aggressive offshore wind, and alternative nuclear development scenarios, respectively. Including NOx and SOx emissions reductions gives: £276.90m, -£16.74m, £73.5m, £174.55m, £267.76m, £223.95m, respectively.

We conclude that the results and qualitative conclusions are not particularly sensitive to the main uncertainties surrounding the input data forecasts, although the one value for the high gas prices scenarios is slightly negative. The positive NPVs from the CBA are invariant to the scenarios assumption changes when excluding NOx and SOx, and invariant when including NOx and SOx but for the high gas prices scenario. This is even more pronounced when including NOx and SOx values. The values are substantial in all cases except the high gas including NOx and SOx and the low gas prices case when excluding NOx and SOx

The other conclusions about P229 impacts are also non-variant to the scenario assumption changes. The impacts on generation are largely expected to be similar. The distributional impacts are similar—some zones will see significant reductions in generation which could lead to significant financial impacts on some companies. Financial impacts of TLF charging favours generation in the South, demand in the North. Transmission system impacts are similar in that all cases are predicted to reduce line flows; congestion impacts are mostly positive across scenarios. Similarly, our conclusions plant entry and exit decisions are not predicted to be sensitive to the assumptions, as the overall level TLF related charges is small relative to TNUoS charging and other factors (local siting, planning) which would impact locational decisions.

The robustness of our analysis and its relationship to previous work on the subject should be noted. Qualitatively, and within a broad but reasonable tolerance, quantitatively, our results are similar to results obtained before.

The analysis undertaken for P229 has advanced the discussion and available information vis-à-vis previous similar BSC TLF related modification proposal studies in that it has undertaken full hourly modelling of the transmission system and despatch, such that the use of snapshot periods and needs for iterative modelling between despatch and loadflow have been eliminated. The modelling undertaken involved the full simulation of the market when estimating the TLFs *ex ante*, and the modelling of the transmission system under competitive despatch given the *ex ante* estimated TLFs from the previous year's data. While this was important in that it simulated as closely as possible the way TLFs will actually be implemented under P229, it should be noted that based on the modelling, even greater benefits from TLFs could be achieved by reducing the differentials between (due to time/uncertainty) the *ex ante* estimated TLFs and the TLFs that actually occur on the settlement period.

The potential mismatch between the TLFs estimated *ex ante* and the 'correct' TLF signals was a source of concern in previous work. Additional scenario analysis such as the fuel volatility case has also showed that while this might naturally reduce the overall benefits of P229, the qualitative conclusion that there is a positive net benefit is preserved.

A number of other concerns raised in previous efforts concerning TLFs have either been addressed or were not considered important or relevant. For example, we used a marginally higher WACC estimate (4.42%) as our discount rate to reflect some concern that the previous CBA, using HM Treasury guideline values of 3.5% might be too low. It should be noted that since the savings are predicted to be positive in almost all years, and since the implementation costs are low, the qualitative conclusions are not found to change substantially under the alternative discount rate scenarios. Given this result one can conclude that the overall results are not likely to be sensitive to a reasonable range of changes to the main underlying parameters.

9 Appendix A: List of Acronyms

CBA: Cost-Benefit Analysis

TLFs: Transmission Loss Factors

WACC: Weighted Average Cost of Capital

TPCR: Transmission Price Control Review

DPCR: Distribution Price Control Review

BATECT: Best Available Technique Emission Control Technologies

CO_2: Carbon Dioxide

NOx: Nitrous Oxide (urban smog, acid rain pollutant)

SOx: Sulphur Dioxide (acid rain pollutant)

PROMOD: Ventyx software modelling programme used for this report

NPV: Net Present Value

EU ETS: European Union Emission Trading System

TNUoS: Transmission Network Use of System

BSC: Balancing and Settlement Code

GSP zone: Grid Supply Point

TLM: Transmission Loss Multiplier

GBEM (Great Britain Electricity Market):

LMP: Locational Marginal Price

FTR: Financial Transmission Right

LP: Linear Programming

DEFRA: Dept. for Environment, Food and Rural Affairs

O&M: Operations and Maintenance

DC: Direct Current

TOR: Terms of Reference

IT: Information Technology

ONS: Office of National Statistics

BERR: Dept. for Business, Enterprise and Regulatory Reform

OFGEM: Office of Gas and Electricity Markets

OFT: Office of Fair Trading

CC: Competition Commission

CER: Commission for Energy Regulation (Ireland)

CAPM: Capital Asset Pricing Model

BOE: Bank of England

LIBOR: London Interbank Offer Rate

BB: Bloomberg

EdF: Electricité de France

E.ON: Energy ON (Germany)

GdF: Gaz de France

NEM: National Electricity Market (Australia)

OLS: Ordinary Least Squares

I&C: Industrial and Commercial

RECLAIM: Regional Clean Air Incentives Market (USA)

MethodEx: Methods and data on environmental and health externalities

ExternE: Methodology for generating external costs

CAFÉ-CBA: Clean Air For Europe Cost Benefit Analysis

WHO: World Health Organisation

GHG: Greenhouse Gas

BAU: Business As Usual

CCGT: Combined Cycle Gas Turbine

CHP: Combined Heat and Power

NGC: National Grid Company

NBP: National Balancing Point

GBEM: Great Britain Electricity Market

IEA: International Energy Agency

ECX: European Climate Exchange

CCS: Carbon Capture Storage

NII: Nuclear Installations Inspectorate

NDA: Nuclear Decommissioning Authority

LCPD: Large Combustion Plant Directive

FGD: Flue Gas Desulphurisation

UK NERP: UK National Emissions Reduction Plan

NGC SYS: National Grid Company

TEC: Total Export Capacity

TEC: Transmission Entry Capacity