



The Impact of Changes in Access Charges on the Demand for Coal

Report for ORR

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Executive Summary

This report, by NERA Economic Consulting for the Office of Rail Regulation (ORR), examines the likely impact of increased track access charges on electricity supply industry (ESI) demand for coal, nuclear fuel and biomass. Previous work commissioned by ORR has suggested that these are market segments that may be able to pay higher track access charges, and thus make a greater contribution to Network Rail's freight-specific costs, with relatively little impact on demand.

The immediate context for this study is the review of freight charges that ORR is carrying out as part of Periodic Review 2013 (PR13), which will determine the level and structure of track access charges to apply for the five year period from April 2014 ("CP5"). ORR also asked us to consider certain wider impacts, including any increase in electricity bills, impacts on current or planned investments, and the implications for Scottish open cast coal mining.

ESI demand for different types of fuel is determined by the demand for electricity at different times and the mix of electricity from coal, nuclear, gas and other sources that can meet these different levels of demand at the lowest cost. In theory, therefore, an increase in the delivered cost of coal could reduce total ESI demand for coal if it moves some coal-fired power stations to a lower position in the "merit order" that ranks power stations by marginal cost. A reduced expectation of demand (or lower expected margins when a power station does operate) may also affect decisions about the working life of coal-fired stations, and whether they choose to opt in or out of the requirements of the EU Industrial Emissions Directive (IED).

To estimate the impact of higher track access charges on ESI demand for coal and nuclear fuel, we have used NERA's EESyM model, a detailed "fundamentals" model of the British electricity market that has been used in a wide range of previous projects for energy industry firms and investors. The model uses public domain information on the operating characteristics of individual power stations, together with forecasts (from external agencies) of coal, gas and other prices and details of future regulatory requirements, to provide detailed forecasts of plant dispatch, fuel use, prices and investment decisions.

Even if there is no change in track access charges, NERA's model predicts that, following an increase (due to projected commodity prices) in the short term, by 2014 ESI coal demand will fall back to the levels experienced in 2009 and 2010. This fall reflects both a significant amount of new and efficient gas generating capacity that will come online, and also the introduction of the UK Carbon Price Floor. Even though independent forecasters expect international gas prices to increase faster than coal prices over the next few years, this is more than offset by the impact of the higher CO₂ price.

ORR asked us to examine the impact of six different access charging options. From a situation where the average track access charge for ESI coal traffic is equivalent to £2.25 per thousand net tonne kms (plus a freight-only line charge of just over 60p per thousand net tonne kms), we have estimated the impact of:

- as the “central” option, an increase equivalent to £10 per thousand net tonne kms;¹
- alternative increases of £5 and £15 per thousand net tonne kms;
- a variant on the £10 increase that, absent any change in volumes or routes, would generate the same total revenues but where only half of the increase is distance-related. This is an increase of £0.765 per net tonne plus £5 per thousand net tonne kms
- a higher increase of £25 per thousand net tonne kms; and
- a much higher increase (we tested an increase of £100 per thousand net tonne kms) in track access charges for nuclear fuel.²

Rather than realistic policy options, the last two of these are simply designed to test the sensitivity of demand and the presence of tipping points, including the proposition that the demand elasticity for nuclear fuel with respect to track access charges is very low indeed. As transport costs are a very small proportion of the costs of nuclear power generation, and the marginal cost of nuclear power is low compared with the costs of coal or gas generation, even such a high increase does not have a material impact on the predicted demand for, or transport of, nuclear fuel.

For almost all model runs, we have assumed that all of the cost increase is passed on in full to generators, and that the proportions of coal that each power station sources from and transports via different routes remain unchanged. Thus the increase in the delivered price of coal at each power station is simply the increase in track access charge (per net tonne km) multiplied by the average distance coal travels to that power station.

There are a number of possible changes that could mean that not all of the increase is passed on to generators. These include decisions by coal producers, freight operating companies (FOCs) or port operators to absorb some of the increase themselves, or by generators to change certain transport routes so as to reduce the average distance that coal travels. To illustrate the potential impact of such changes, we carried out a sensitivity test that shows how demand would be affected if Scottish coal producers were to absorb the additional cost increase relative to imports, and if generators were to complete the process of rationalising port usage in order to eliminate long distance rail journeys (eg from Hunterston to Aire Valley and Trent Valley stations) for imported coal.³

We also carried out a sensitivity test to investigate whether the impact of higher track access charges is different if gas prices are significantly lower than assumed in our base case

¹ Throughout this report these options, and the resulting impacts on Network Rail revenues, are expressed in October 2010 – September 2011 prices. In practice, if this or another option were implemented, the increase would be introduced as a change in the access charge per gross tonne mile. An increase of £10 per thousand net tonne kms is equivalent to an increase of £8 per thousand gross tonne miles.

² To provide a sense of scale, we estimate that an increase in track access charges of £100 per thousand net tonne kms would increase the variable cost of nuclear generation by up to £1.40 per MWh of electricity generated. However, in practice the impact depends on the distance that nuclear fuel is transported, and for most power stations the impact is lower.

³ It is possible that some further rationalisation could occur before 2014, regardless of decisions on future track access charges. In this case, the risk that increases in track access charges will lead to a significant reduction in the average distance that coal travels by rail (and therefore a reduction in tonne kms) will be lower.

forecasts. While lower gas prices could lead to a very substantial reduction in both coal-fired generating capacity and ESI demand for coal, the proportionate impact of an increase in track access charges is still similar to that predicted in our base case.

Table 1 summarises the estimated reduction in ESI coal demand over the five years from 2014 to 2018, showing the impact on both rail freight lifted (net tonnes) and rail freight moved (net tonne kms). A £10 increase would reduce total demand by around 5 per cent, with correspondingly smaller or larger impacts for increases of £5, £15 or £25.

Compared with the impact of a simple increase of £10 per 1000 net tonne kms, an increase that is only partly distance-related would have a slightly higher impact on total ESI demand for coal, and a slightly lower impact on the volume of rail freight moved (ie net tonne kms), but the differences are small. And the results confirm that the impact on total coal demand will be reduced if other parties (such as Scottish coal producers) absorb some of the increase, however the impact on freight tonne kms could be exacerbated if the increase in track access charges leads to a greater reduction in long distance coal flows.

**Table 1
Change in ESI Coal Demand 2014-18**

	<i>Increase in charge per 1000 gross tonne miles (£)</i>	Change in net tonnes lifted	Change in net tonne kms moved
£10 increase (per 1000 net tonne kms)	8	-4.6%	-5.0%
£5 increase	4	-2.1%	-2.4%
£15 increase	12	-7.4%	-8.7%
£10 increase – only 50% distance related	8	-5.1%	-4.7%
£10 increase – partial pass through + route changes	8	-3.6%	-14.8%
£10 increase – with lower gas price forecasts	8	-5.8%	-6.3%
£25 increase	20	-12.6%	-16.2%

Assuming no change in the proportions of coal that each power station obtains from different sources, the £10 increase would generate average additional revenues of £53 million per year during CP5,⁴ which would reduce the amount of subsidy that Network Rail requires from the Department for Transport and Transport Scotland. The £5 and £15 increases would generate average additional revenues of, respectively, £27 million and £76 million per year.

The increase in track access charges would have only a modest impact on customers' electricity bills. We estimate that the £10 increase in track access charges would lead to a less than 1 per cent increase in bills for the majority of electricity customers, with most customers experiencing a much smaller proportional increase in electricity costs.

⁴ This does not take account of the impact of lower traffic volumes on Network Rail's income from variable track access charges, as this should be offset by a corresponding reduction in Network Rail's costs. But it does include the impact on income from the current freight-only line charge.

Over the last few years, Scottish coal producers have maintained a relatively constant level of output, despite very significant fluctuations in international coal prices, which are now substantially higher than they were in 2009. In the short to medium term, therefore, it seems plausible that producers would adjust their prices as necessary so that they can continue to sell to power stations in England, rather than accepting a reduction in demand caused by increased transport costs. In the longer term, however, it is possible that increased track access charges could lead to some slow down in the development of future open cast sites.

It is more difficult to assess the possible impact of higher track access charges on ESI use of biomass. There are different forms of biomass generation, not all of which involve rail transport. And, importantly, the impact of any increase in track access charges will depend on the extent to which government subsidies are also adjusted in order to ensure that biomass generation continues to make its expected contribution to helping the UK meet its renewable energy targets.

Our analysis confirms that increasing track access charges would have a negligible impact on demand for the transport of nuclear fuel. Even if track access charges for nuclear fuel were to increase by £100 per thousand net tonne kms, we find no impact on the modelled output from nuclear generators. This is not surprising, as nuclear plants have low variable costs of production relative to competing technologies, so it is typically economic for them to produce in as many hours of the year as possible.

1. Introduction

This report, by NERA Economic Consulting for the Office of Rail Regulation (ORR), examines the likely impact of increased track access charges on electricity supply industry (ESI) demand for coal, nuclear fuel and biomass. It also considers certain wider impacts, including any increase in electricity bills, impacts on current or planned investments, and the implications for Scottish open cast coal mining.

The immediate context for this study is the review of freight charges that ORR is carrying out as part of Periodic Review 2013 (PR13), which will determine the level and structure of track access charges to apply for the five year period from April 2014. Alongside ORR's work, Network Rail is carrying out analysis to examine the variable costs associated with freight traffic and the costs of freight only lines.

As reported in the Command Paper *Reforming our Railways*, published earlier this month, the UK Government is supporting rail freight through the continuation of the mode shift revenue support scheme, a clear planning policy framework and consideration of further investment in the Strategic Freight Network. In return, it is looking to freight operators to continue to pursue cost savings, "go anywhere" access rights are being reviewed, and ORR is considering possible changes to track access charges so that they cover a greater share of the infrastructure costs associated with rail freight.⁵

The formal framework within which higher access charges might be introduced is set out in Schedule 3 of The Railways Infrastructure (Access and Management) Regulations 2005, which implements the charging and capacity allocation provisions of Directive 2001/14/EC. This states that mark-ups based on "efficient, transparent and non-discriminatory principles" may be added to charges in order to allow greater cost recovery. However, the effect of this should not be "to exclude the use of infrastructure by market segments which can pay at least the cost that is directly incurred as a result of operating the railway service, plus a rate of return which the market can bear".

ORR has already commissioned an initial study from MDS Transmodal that considers the likely impact of higher track access charges across all rail freight market segments, and some follow-up work addressing, among other things, substitution between modes and port choice. Based on the findings of the initial study, ORR commissioned NERA to carry out a more detailed analysis of ESI demand for coal, nuclear fuel and biomass, and how this might be affected by track access charges.

To carry out this analysis, we have made extensive use of NERA's detailed model of the British electricity market. This model is described in Section 2.5, along with details of the specific track access charging options that ORR asked us to examine, and a general description of the factors that influence ESI demand for different types of fuel. Section 3 then describes our modelling of ESI demand for coal and nuclear fuel, and Section 4 considers certain wider impacts. Section 5 sets out our conclusions.

⁵ See paragraphs 4.46 and 4.47 of Department for Transport, *Reforming our Railways: Putting the Customer First*, Cm 8313, March 2012.

During the course of this project, we have benefitted from discussions with a number of energy and rail industry stakeholders, as well as participating in rail industry meetings on the development of track access charges. We would like to thank all those who assisted us in this way. A list of stakeholders we consulted is at Appendix A.

2. Summary of Key Assumptions

In this section we discuss the charging options examined and our modelling approach. We also present the key commodity price assumptions used in our power market modelling tool.

2.1. Options Examined

At present, freight train operators (also known as freight operating companies, or “FOCs”) pay track access charges that are based on the estimated variable costs of using the rail network. For ESI coal traffic, the current charge is equivalent to an average of £2.25 per thousand net tonne kms.⁶ In addition, both ESI coal and spent nuclear fuel traffic pays an additional charge based on the cost of freight only lines. For ESI coal this is equivalent to just over 60p per thousand net tonne kms.

ORR asked us to examine six different options for an increase in the track access charges for ESI coal, nuclear fuel and biomass traffic:⁷

- as the central option, an increase of £10 per thousand net tonne kms;⁸
- an increase of £5 per thousand net tonne kms;
- an increase of £15 per thousand net tonne kms;
- a variant on the £10 increase that, absent any change in volumes or routes, would generate the same total revenues but where only half of the increase is distance-related. This is an increase of £0.765 per net tonne plus £5 per thousand net tonne kms
- a higher increase of £25 per thousand net tonne kms; and
- a much higher increase (we tested an increase of £100 per thousand net tonne kms) in track access charges for nuclear fuel.

Rather than realistic policy options, the last two of these are simply designed to test the sensitivity of demand and the presence of tipping points, including the proposition that the demand elasticity for nuclear fuel with respect to track access charges is very low indeed

We estimated the likely impact of each of these options under our base case forecasts, as described in Section 3.2 below.

In addition, we carried out two sensitivity tests to examine the impact of the £10 increase in cases where:

⁶ In practice, track access charges are levied on the basis of gross tonne miles, which include both empty workings and the weight of locomotives and wagons. For ESI coal traffic, the average charge of £2.25 per thousand net tonne kms is equivalent to a charge of £1.80 per thousand gross tonne miles (Source: MDS Transmodal, *Impact of changes in track access charges on rail freight traffic – Stage 1 Report*, February 2012).

⁷ Throughout this report these options, and the resulting impacts on Network Rail revenues, are expressed in October 2010 – September 2011 prices

⁸ This is equivalent to an increase of £8 per thousand gross tonne miles.

- not all of the increase is passed on to generators, and if it also leads to the elimination of some longer distance flows. Some of the reasons why this could happen are discussed in Section 3.3 below; and
- future gas prices are lower than assumed in our base case forecast.

2.2. Modelling Approach

The effect of the options described above on demand for ESI coal depends on how the increased cost of rail freight feeds into the production decisions of coal-fired generators. In this chapter, we describe how the electricity market works in order to identify the range of factors, including freight charges, that drive the production decisions of power stations. We also outline the approach we take to modelling the impact of the options and describe the input assumptions to this modelling process.

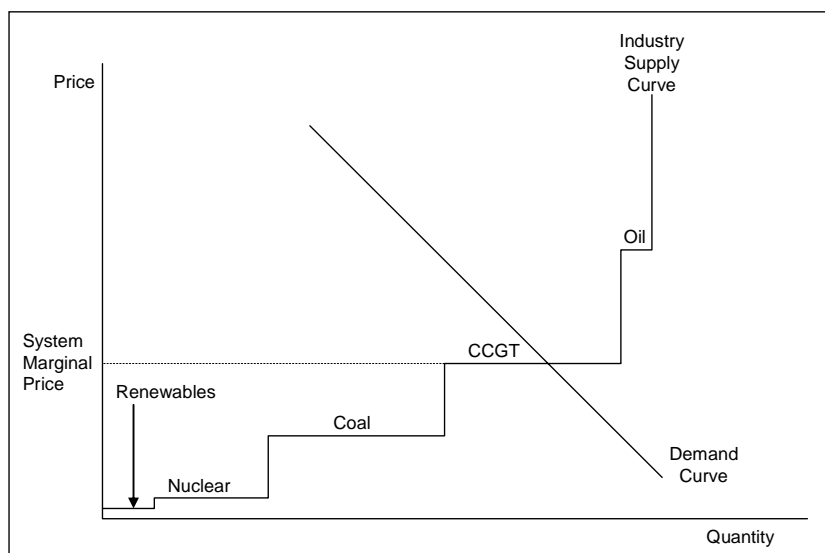
2.3. The GB Generation Market

Generators in GB compete within a market framework known as the British Electricity Transmission and Trading Arrangements (BETTA), which includes rules for accessing the GB transmission system and making generation sales. A variety of market places exist within the BETTA framework that provide alternative outlets for generation, including power exchanges such as APX Power UK, over the counter (OTC) markets and the balancing market for last minute adjustments operated by National Grid. However, the possibilities for market participants to trade in any or all of these alternative markets means that in practice they are closely integrated, and hence we treat these markets as comprising a single wholesale market for the purpose of our analysis.

As in any market, prices in the GB wholesale electricity market adjust to match available supplies to demand, as illustrated in Figure 2.1, with the market price set by the marginal cost of the most expensive generator operating at a given demand level. Figure 2.1 shows that differences in the marginal cost of plants define a ranking or “merit order” of generators, in which plants are ranked in order of increasing marginal cost, with the lowest marginal cost plants on the left-hand side of the graph. In this simplified example, renewable and nuclear generators produce first. Then if more electricity is demanded, coal generators produce, then Combined-Cycle Gas Turbine (CCGT) plants, then oil-fired generators provide “peaking” capacity.⁹

⁹ In this simplified example, the marginal cost of coal fired generation is lower than the marginal cost of generation from a CCGT plant, but this ranking is just a schematic illustration.

**Figure 2.1
Stylised Industry Supply and Demand Curve**



In practice, the GB wholesale electricity market effectively operates by each plant making an “offer” stating the lowest price at which it is willing to supply a given quantity of electricity in each half hour period, with the set of all offers making up the industry supply curve. The intersection of this industry supply curve with the market demand curve (constructed based on demand “bids”) determines the market price.

2.4. Competition between Coal and Gas Generators

Coal-fired power stations in Great Britain (GB) mainly compete with gas-fired CCGT power stations to supply electricity in the GB wholesale market. The ranking of these sources of generation capacity depends mainly on the relationship between gas, coal and CO₂ prices. Historically, production from coal plants has tended to be cheaper than production from CCGTs *in the winter*, when gas prices are high due to the high levels of winter gas demand, and more expensive *in the summer*, when gas prices are low due to low summer demand for gas. Hence, historically coal plants tended to operate as baseload plant in the winter (i.e., 24 hours a day and 7 days a week), and as mid-merit or peaking plant in the summer (day-time on working days).

The impact of an increase in track access charges on production from coal plant depends on the size of the increase, and the extent to which this affects the ranking of plants in the merit order as illustrated in Figure 2.2 and Figure 2.3, based on the historical demand pattern seen in the UK.

As illustrated in Figure 2.2, in winter a small increase in freight costs may reduce the profits captured by coal-fired power stations without affecting their level of production. In the summer, when coal plants are the marginal source of supply, the increase in freight costs increases the price coal-fired power stations need to charge and hence the market price, but

again, without materially affecting the level of production from coal-fired plants – because electricity demand (depicted by the vertical line D) is effectively inelastic.

With a large increase in track access charges, the picture in summer is similar to the one we saw with a small increase in freight charges, as illustrated in Figure 2.3. However, in winter the large increase in track access charges leads to a switch in the merit order, with coal-fired plant becoming the marginal source of supply. In this case, as shown in Figure 2.3, *the production from coal plants falls as a result of the increase in freight charges.*

Figure 2.2
The Impact of a *Small* Increase in Track access Charges

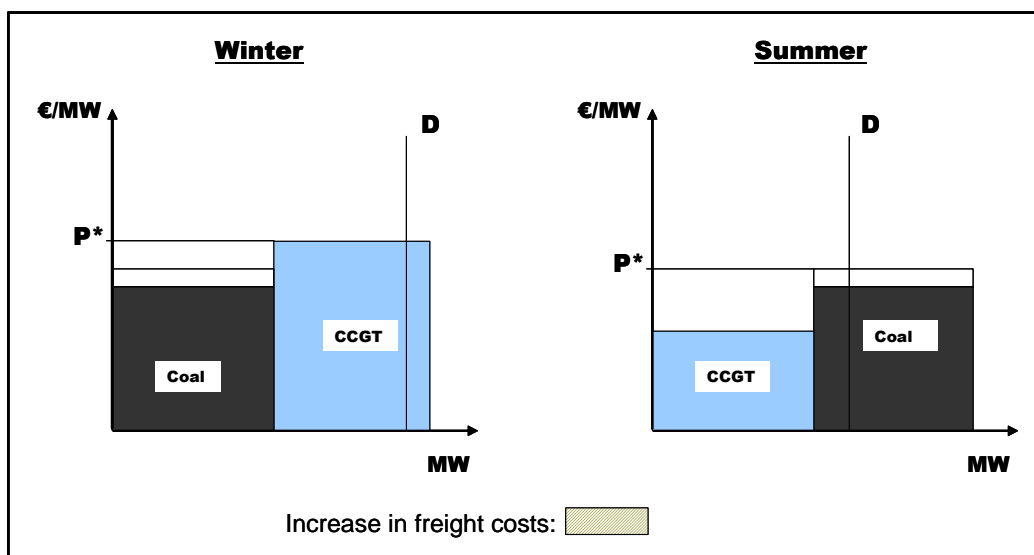
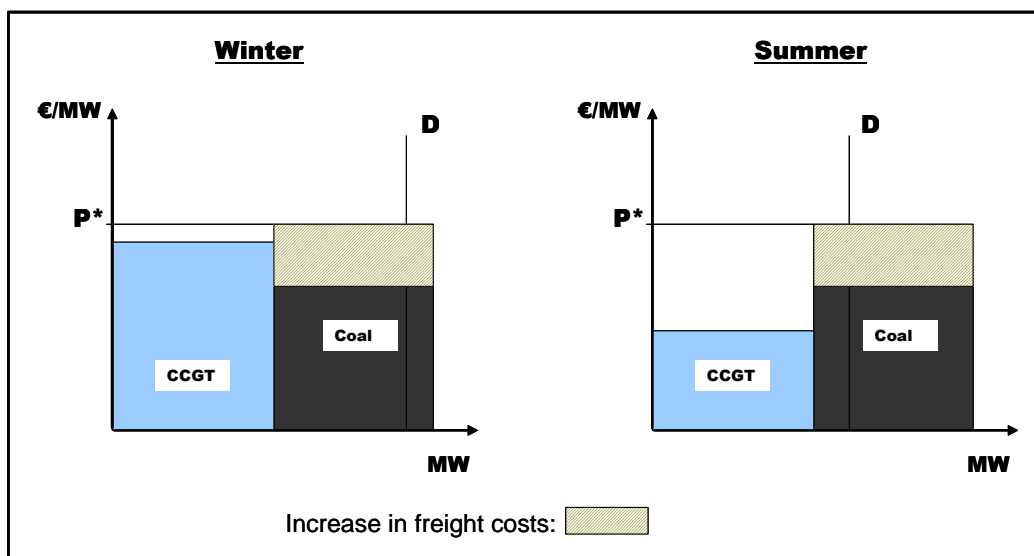


Figure 2.3
The Impact of a *Large* Increase in Track access Charges



Hence, within the schematic framework illustrated in Figure 2.2 and Figure 2.3, an increase in track access charges may affect production from coal-fired power stations depending on the scale of the increase.

The charts above are stylised representations of reality. In practice, the likely impact of a given increase in track access charges is more complex than depicted above. For instance, the thermal efficiency of coal-fired and CCGT plants (i.e., the efficiency with which they convert fuel to electricity) varies on a spectrum, which may create an overlap between the marginal costs of these plant both in winter and summer, and both plant types also compete at the margin with other sources (e.g., open cycle gas turbines, oil plant, imports). Also, regulations impose running constraints on many plants, particularly coal plants.

In addition, gas and carbon price fluctuations mean that the relationship between coal and gas plants differs from one year, quarter, or day to the next, and there have been changes in the historical seasonal patterns in gas prices.¹⁰ However, gas and coal-fired generators still compete within the British wholesale electricity market, and changes in delivered commodity prices can affect their relative positions in the merit order.

In summary, the coal demand depends on a variety of factors:

- **relative trends in underlying coal and gas prices:** gas prices have been very volatile over the past five years, placing coal plants in varying positions in the merit order;
- **trends in CO₂ prices:** the EU Emission Trading Scheme (ETS) means fossil fuel generators pay for emitting CO₂. Coal-fired power stations emit approximately three times more CO₂ per unit of output than CCGTs, so changes in CO₂ prices have a larger impact on coal plants' marginal costs than CCGTs. Since the introduction of the EU ETS, CO₂ prices have varied considerably and are currently at a relatively low level in a historical perspective. However, the UK Treasury has recently announced a Carbon Price Floor (CPF), which will, starting from 1 April 2013, increase the cost of carbon emissions by UK power generators considerably, bringing the cost of carbon emissions in the UK to more than three times the current level by 2020¹¹;
- **trends in investment:** government subsidy schemes are currently driving new investments in new renewable generation capacity, particularly in the form of wind. These developments create both threats and opportunities for coal plants. Renewable generation capacity is offered to the market at very low marginal cost, and therefore tends to push coal and gas generation down in the merit order. Investments in renewables may therefore displace existing coal and gas plants. However, wind generation also has a very volatile output pattern, so coal plants may also benefit from high electricity prices in periods of relative scarcity caused because there is, for example, little or no wind. Other new investments that may displace existing coal plants in the merit order include new

¹⁰ For instance, National Balancing Point (NBP) gas prices fell substantially around 2009-10, coinciding with the economic downturn and a relative surplus of gas in Europe. Recent volatility in crude oil prices has also contributed to swings in gas prices.

¹¹ Current prices are around £7-9/tCO₂. The carbon price floor is set to increase to £30/tCO₂ by 2020 (in real 2009 prices).

CCGTs which are already in various stages of development, as well as the possibility of new Carbon Capture and Storage (CCS) power stations;

- **constraints imposed by the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED):** Since 2008, some existing coal plants have accepted limits on their operating hours imposed by the LCPD which tightened restrictions on SO₂, NO_x and dust emissions from large combustion plants. From 2016, all GB coal plants will also face tighter restrictions from the IED, and will need to decide whether to make investments in emissions control equipment or accept limited running hours in the following period.¹² Plants operating with limited running hours may find it most profitable to conserve their running hours for times when power prices are particularly high, rather than running power plants even if the price is above their direct dispatch cost.¹³

These factors affect the relative competitiveness of coal plants compared to competing technologies, the size of the market within which they compete, and/or the availability of coal plants to supply electricity to the system. Thus they each potentially influence the impact of changes to freight track access charges on production from coal plants.

2.5. NERA's EESyM Model

To take into account the factors discussed above, we have examined the impact of an increase in freight track access charges using our model of the GB electricity market, EESyM.¹⁴ EESyM is a fundamentals model of the electricity market, which in essence captures the interaction of detailed supply and demand curves for the GB (and neighbouring) electricity markets to forecast market outcomes, as illustrated schematically in Figure 2.1 above. The structure of EESyM is illustrated in Figure 2.4.

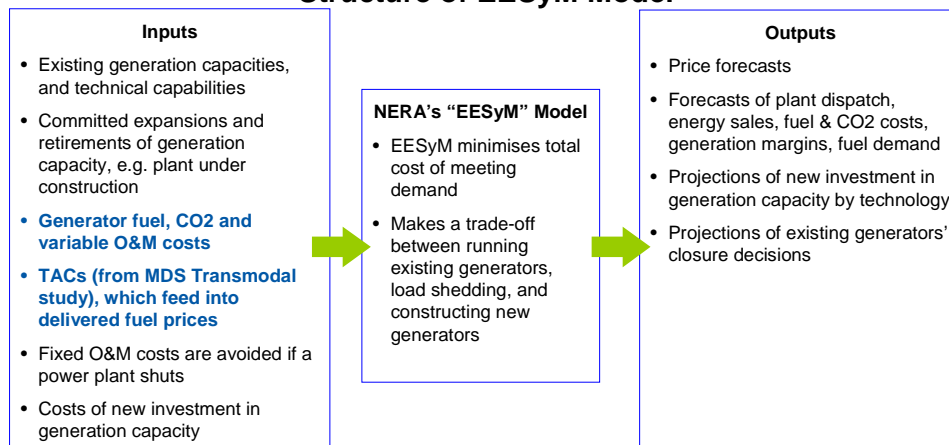
As the figure shows, EESyM also optimises investment in new thermal power generation capacity, which will come online if it can be profitably developed. It also selects the timing of closures of existing thermal generators, by comparing their earnings with their avoidable fixed costs. It also selects the investment decisions coal plants need to make when deciding whether to “opt-in” or “opt-out” of the IED, as we describe further below.

¹² LCPD opted out plants are constrained to run a maximum of 20 000 hours from 2008-2015 when they have to close. LCPD opted-in plants have the option of complying with emission legislation (which means installing SCR at a substantial cost) or “opting out” of the IED. Plants opted out of the IED are constrained to a maximum of 17500 running hours from 2016-2023 following which they have to close.

¹³ Energy-constrained plants (i.e. those with limited operating hours) will only run when the power price exceeds their *opportunity* cost of production, i.e. what they would have gained from producing at a different point in time, plus their avoidable fuel and CO₂ costs.

¹⁴ EESyM is a tested and proven proprietary model of the UK and European electricity markets, which we have used extensively on a range of regulatory, litigation, due diligence and competition policy assignments. It uses a standard economic framework widely recognised in the literature on electricity markets, and it is populated by objective data drawn from published sources.

**Figure 2.4
Structure of EESyM Model**



As the first step of our analysis, we used EESyM to construct a realistic baseline projection of GB power market evolution based on assumptions regarding key drivers (including forecasts of fuel and CO₂ prices, investment, demand, etc). This baseline projection accounts for the cost of delivering coal to power stations, where the average track access charge for ESI coal traffic is equivalent to £2.25 per thousand net tonne kms (plus a freight-only line charge of just over 60p per thousand net tonne kms). Taking these assumptions, EESyM dispatches GB power stations in “merit order” to meet power demand in every hour of the modelling horizon, and computes a range of outputs, including total ESI coal demand.

In practice, the data we feed into EESyM’s dispatch algorithm represents the GB power market at a high level of granularity. For example, we model each individual coal plants separately with separate estimates of each plant’s efficiency and the transportation costs it faces to obtain coal. For gas plants, we group plants with similar characteristics into seven bands according to efficiency. Other types of generation capacity are grouped by generation technology. We also account for how demand varies over the year by calculating patterns of dispatch for 100 levels of demand within each quarter to represent the range of demand variation. We then aggregate results from these 100 levels of demand per quarter to obtain annual outputs.

2.6. Factors Affecting Future Electricity Industry Demand

2.6.1. Plant efficiencies

We used historic plant production and emissions data, published as part of the National Allocation Plan (NAP), to derive plant-level efficiencies for GB thermal power stations.¹⁵

¹⁵ For emissions data, we used NAP Phase I data from Defra’s *Installation Level Allocations* spreadsheet: <http://www.defra.gov.uk/environment/climatechange/trading/eu/nap/install.htm>. For historic generation data we used NAP Phase II data from the DTI. See: <http://www.dti.gov.uk/energy/environment/euets/phase2/allocation/page27064.html>.

Where NAP data were unavailable for individual plants, we extrapolated efficiency for these plants using information on the efficiencies of similar types of plant.

As noted above, we model the effect of increasing freight track access charges on each GB coal-fired generator separately. For other types of plant, we group similar types of generator together. To account for the differing efficiencies (and hence marginal costs) of CCGT plants, we group CCGT generators into seven efficiency bands, ranging from 41 per cent to 52 per cent (sent-out, gross calorific value). We assume all new plants that are due to come on line over the modelling period have an efficiency of 52 per cent.¹⁶

2.6.2. Plant capacities

We source plant capacity information from the Platts Powervision database for all plants connected to the GB transmission network, which are currently online or which Platts lists as “under construction”. Platts also contains information on planned capacity that is not yet under construction. However, because generating companies often announce new generation projects that do not come to fruition, this is likely to provide an upper limit on the amount of new capacity. Due to this uncertainty over what capacity will come online, we programme only that plant which is online or under construction, and allow EESyM to select investment in other new entrant capacity endogenously.

As described further below, we also make assumptions regarding the deployment of the renewable generation capacity that is expected to come online in the coming years to achieve the government target of sourcing 30 per cent of generation from renewables by 2020. We do not endogenously model investment in renewable generation within EESyM, as it is driven by government policy and encouraged through subsidies, and not by underlying conditions in the power market.

2.6.3. Fuel and CO₂ Prices

In our central case, we construct gas, oil, coal and CO₂ price forecasts using forward curve information (as at January 2012) for the first two years of the modelling horizon, as beyond that period forward markets are illiquid and so may not provide a reliable basis for forecasting commodity prices.¹⁷ From then, we assume that fuel prices converge to the long run levels projected in the World Energy Outlook 2011, published by the International Energy Agency (IEA).¹⁸

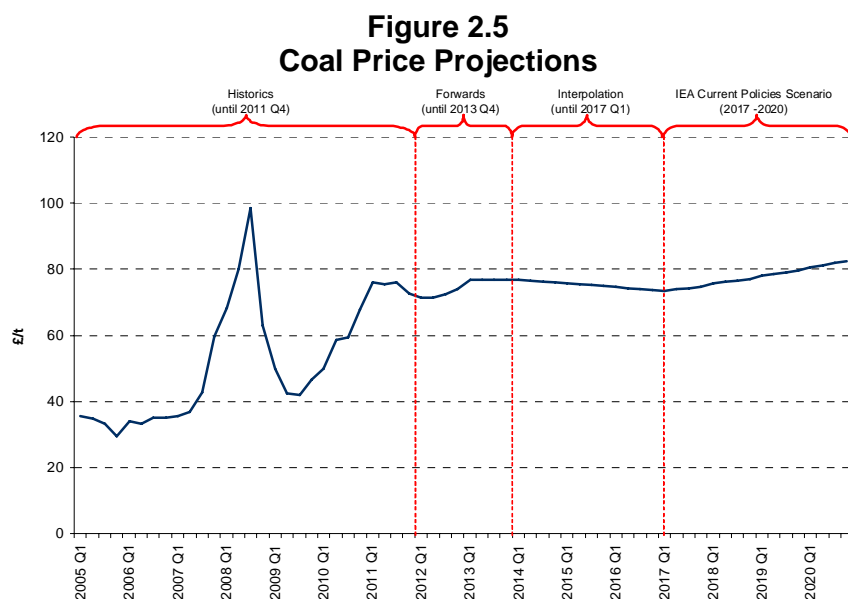
¹⁶ For all categories of generation plant, our EESyM model uses “full load” thermal efficiencies to construct a merit order. That is, it assumes that the cost of running each generation unit is determined by the costs incurred on a per MWh basis when that plant is running at full load. Being a load duration curve model, it does not explicitly account for unit commitment costs (start-up costs, no load costs, or part-loading inefficiencies) when it decides which plants are “in merit”. For this study, the main driver of our estimated impact on ESI coal demand from increasing track access charges is the extent to which coal plants compete with gas plants. Because our model excludes start-up costs for both coal and gas, this simplification is unlikely to have a material impact on our results as it does not bias the model’s decision between the two technologies.

¹⁷ Gas and oil forward prices from Bloomberg. Coal forward prices from Heren. CO₂ forward prices from Point Carbon. In constructing our forecasts, we have used forward curve information for exchange rate forecasts from Bloomberg. We have also used forecasts of US and Eurozone inflation, drawn from Consensus Forecasts Global Outlook: 2006-2015, Consensus Economics Inc., 2006.

¹⁸ International Energy Agency, World Energy Outlook, November 2011.

Our approach to forecasting coal prices essentially assumes that the cost of coal obtained from international markets sets the market price for coal within Great Britain (i.e. import price parity). Hence, we base our coal price forecast on historic and forward ARA API#2 coal prices, to which we add £6/tonne to reflect the extra costs of shipping coal to Britain as compared to the Netherlands, and the costs of accessing port infrastructure in Great Britain.¹⁹ From the end of the liquid forward curve for ARA coal, we use IEA coal price forecasts as a guide to future ARA prices.

As shown in Figure 2.5, falling coal demand across Europe due to the impact of decarbonisation policies, offset by rising coal demand in emerging markets such as China, means the IEA’s long-term forecast for coal prices is relatively flat overall.²⁰



Source: Short term: Bloomberg historics and forwards. Long term: IEA World Energy Outlook 2011, Current Policies scenario (p64). Converted using quarterly average FX rate

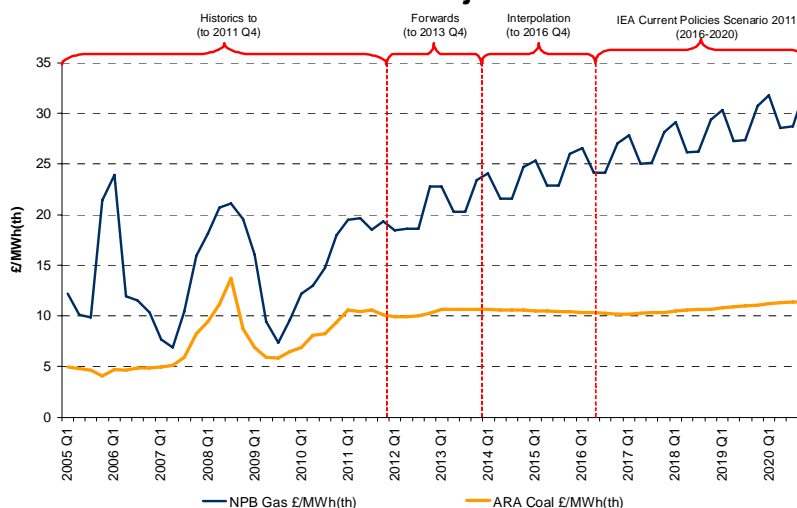
In contrast, Figure 2.6 shows an upward trend in gas prices, which is driven by the link between gas and oil pricing built into the IEA’s price forecasts, and the IEA’s projection of continued growth in international crude prices out to beyond 2020.²¹ However, the impact of this widening gap between the prices of coal and gas on the electricity merit order will be mitigated in the coming years by the expected upward trend in CO₂ prices in the UK, driven largely by the UK government’s decision to impose the CPF, as illustrated in Figure 2.7.

¹⁹ UK Electricity Generation Costs Update, Mott MacDonald, June 2010, Section 6.3.

²⁰ IEA World Energy Outlook 2010, page 200.

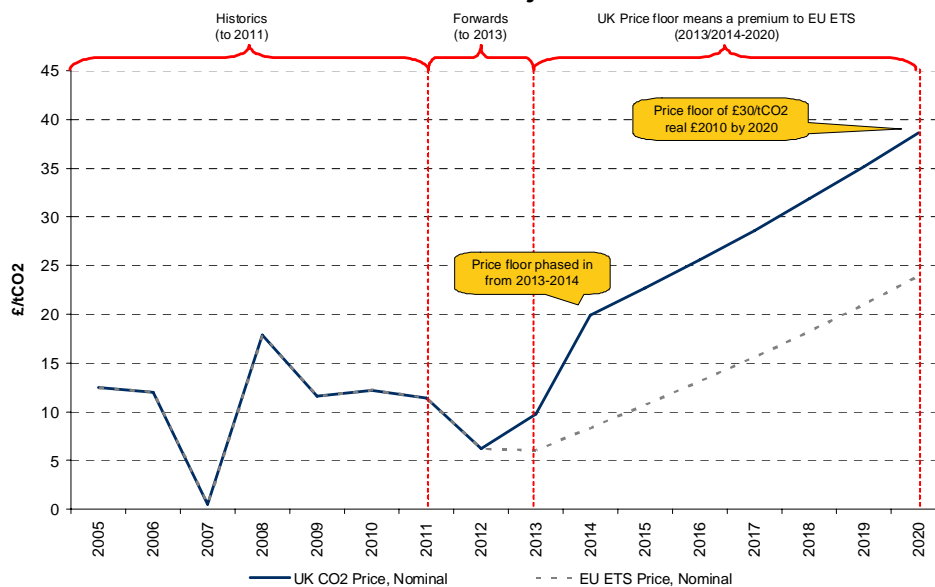
²¹ As well basing our gas price projection on forward prices and long-term IEA price forecasts, we also assume a season spread in gas prices based on the current forward curve, and a daily gas price shape to capture within-year gas price volatility that we calibrate to historic (2009) National Balancing Point price data.

Figure 2.6
Gas Price Projections



Source: Short term: Bloomberg historics and forwards. Long term projection of \$12.6/mmbtu: IEA World Energy Outlook 2011, Current Policies scenario (p64). Converted using quarterly average FX rate. Note: £1/MWh~2.9p/therm.

Figure 2.7
CO₂ Price Projections



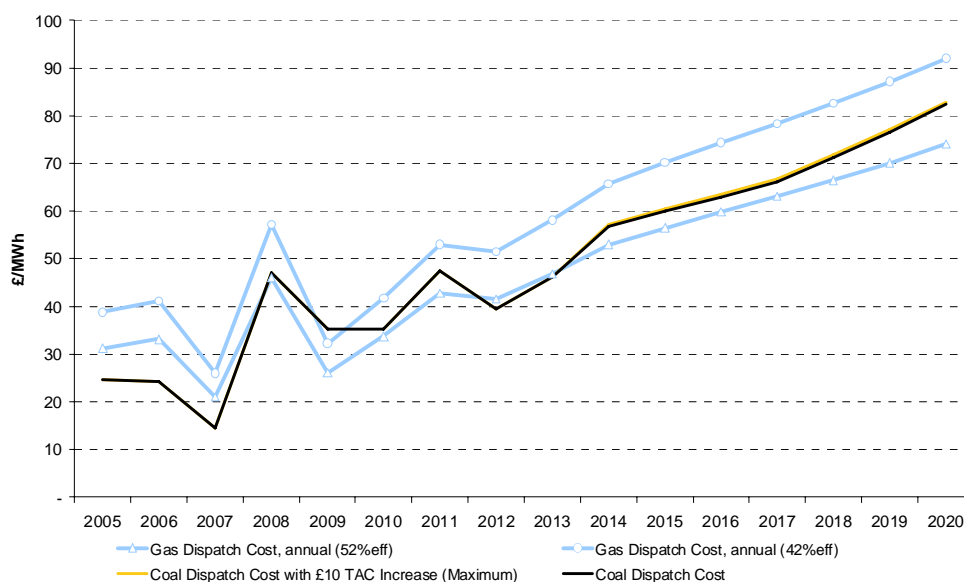
Source for EU ETS: Short term: Bloomberg historics and forwards. Long term projection of \$30/tCO₂ and \$40/tCO₂: IEA World Energy Outlook 2011, Current Policies scenario (p64). Converted using annual average FX rate. Source for UK Carbon price floor: DECC

The overall impact of these coal, gas and CO₂ price projections is shown in Figure 2.8. It shows that in 2012 coal-fired generators tend to have a lower marginal cost than gas-fired CCGTs across the year. However, as CO₂ prices rise in 2013 and 2014, driven by the CPF,

coal generators' position in the merit order falls, and from then on their marginal cost of production sits in the middle of the range of the gas-fired CCGTs on the British system.

To provide a sense of the magnitude of rail freight costs as a proportion of the overall marginal cost of coal generation, Figure 2.8 also shows the impact of increasing freight track access charges faced by ESI coal traffic by £10 per thousand net tonne kms, as compared to the current charge of around £2.25 per thousand net tonne kms. Our estimates show that this change would increase the cost of delivered coal by around £0.5/MWh(th), and hence increase the cost of electricity production in a representative coal station by around £1-£1.5/MWh(e). Given a marginal production cost of around £60/MWh(e), this range corresponds to between 1.7 per cent and 2.5 per cent of total dispatch costs.

**Figure 2.8
Implied Dispatch Cost**



Source: NERA Analysis using data from Bloomberg and IEA World Energy Outlook 2011. The TAC increase is illustrated for the increase of fuel cost for Rugeley B. The effect for other plants is smaller. The marginal cost of gas-fired generation also accounts for gas transport costs.²²

2.6.4. Restrictions on coal generation (LCPD and IED)

As mentioned above, fossil fuel generators are subject to two important EU directives which require them to either comply with emissions limits by making investments in emissions abatement equipment, or limit their running hours, as illustrated in Figure 2.9.

²² Large gas users (such as CCGT operators) pay for gas transport on the British gas transmission network through capacity and commodity charges for use of the transportation network. Under current arrangements, the capacity charge is invariant to utilisation, and so does not affect the short-run marginal cost of generation. The commodity charge is levied on a volumetric basis, and so does affect the marginal cost of generation. We include the commodity charge of gas transport in our model as indicated in recent charging statements published by National Grid's.

See <http://www.nationalgrid.com/uk/Gas/Charges/statements/>.

The Large Combustion Plants Directive (“LCPD”)²³ stems from 2001 and so any opt-in decisions have already been made. Plants could either “opt in” by fitting extra equipment (flue gas desulphurisation, or FGD) to reduce SOx emissions or “opt out” of this directive. Plants which have opted out have to close by end of 2015 and can run for a maximum of 20,000 hours over the period 2008-2015.

The Industrial Emissions Directive (“IED”)²⁴ will supersede the LCPD, and applies only to plants “opted in” to the LCPD (and therefore not closed by 2016). These plants have the option of either (i) “opting in” to the IED by meeting strict emission limits, particularly on NOx emissions, or (ii) “opting out”, which means they have to close by the end of 2023, and face maximum running hour constraints. We assume that coal plants can comply with these emission limits by fitting extra equipment (selective catalytic reduction equipment, or SCR).²⁵ Else they accept a limit of 17,500 running hours between 2016 and 2023, and have to close by end of 2023. We assume that newer gas plants already comply,²⁶ or can fit additional equipment at limited cost.²⁷

In practice, other compliance options are available to coal plants under the IED. In particular, rather than opting in immediately, plants can enter the “Transitional National Plan” (TNP), a UK-wide arrangement under which the IED emission limits are phased in, and which allows for trading of emissions permits between participants. In practice, the NOx limits are likely to be the most important. If they can purchase sufficient NOx permits, the TNP may allow participating coal generators to comply with the IED in the short-term, without incurring SCR investment costs or reducing their running hours. Hence, the impact of the TNP on GB coal generators will depend on the pricing and availability of NOx permits, so its impact is somewhat uncertain.

For the purpose of market modelling, we therefore make the simplifying assumption that coal plants face a binary choice between opting into the IED and fitting SCR, or opting out and accepting limited running hours. As noted above, each coal plant’s “opt-in” or “opt-out” decision is endogenised within the modelling framework.

²³ Directive 2001/80/EC.

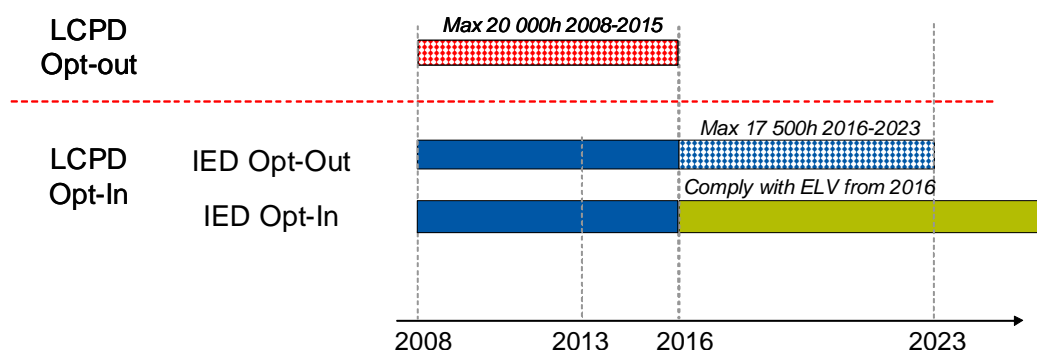
²⁴ Directive 2010/75/EC.

²⁵ We assume the cost of fitting SCR for coal is £79.6/kW in 2009 prices. Source: DEFRA.

²⁶ We assume CCGTs do not need to fit SCR to reduce their NOx emissions to a level that complies with the directive as they can fit low-NOx burners, which are relatively cheap.

²⁷ In our modelling we have assumed a decision has to be made by 2013. We assume that plants with SCR take outages in connection with the retrofits and have slightly lower efficiencies after fitting SCR.

Figure 2.9
Overview of Coal Plant Environmental Constraints



Source: NERA Analysis. Note: ELV = Emissions Limit Value, i.e. the limits on emissions imposed under the IED

2.6.5. Changes in transport costs

Transport costs account for a relatively small proportion of the delivered cost of coal, and an even smaller proportion of the costs of nuclear power generation.²⁸ For this reason, NERA’s model does not feature detailed assumptions about the current transport costs relevant to individual power stations. This is consistent with the overall approach of the model, which is necessarily based on public domain information about the characteristics of individual power stations, and uses generic assumptions about the delivered cost of electricity and gas.

Nevertheless, a significant change in track access charges, if this is passed on to generators, might still be sufficient to change a power station’s position in the merit order. It could increase the cost of coal-fired generation relative to gas, and it might also have a more significant impact on those power stations that transport coal over relatively long distances.

For most of the model runs reported in Section 0, we assume that the increase in the track access charge is passed on, in full, to each generator. Furthermore, we assume that there is no change in coal sourcing and transport decisions, so that each generator faces an increase in the cost of coal equal to the increase in the track access charge multiplied by the average distance that coal travels to the power station.

This approach will provide an upper bound on the likely reduction in ESI demand for coal. In practice, there are two types of change that may protect generators from some of the impact of higher track access charges, and thus lessen the impact on the total ESI demand for coal.

The first possible change is that some of the cost increase might be absorbed at other points in the supply chain. This could occur either

²⁸ We estimate that track access charges account for less than 1% of the total variable costs of a nuclear generator, and in turn the variable costs of nuclear plants tend to be a very small proportion of total costs. However, as described below, the variable cost of a nuclear generator are somewhat uncertain, because it is difficult to derive a reliable estimate of the additional cost that a nuclear plant incurs by producing an incremental MWh of output, or avoids by deciding to produce one less MWh of output.

- because some firms could be placed at a competitive disadvantage as a result of increased transport costs, and therefore take a deliberate decision to reduce their margins in order to retain their current business. This might apply to Scottish coal producers, whose sales to English power stations typically travel significantly longer distances than coal that is imported through English ports, or to ports (notably Hunterston, but also some ports in the far North East of England) that still handle some imports that travel a long distance to the destination power station; or
- as a result of pressure from generators and/or competition between FOCs. In the short term, existing contracts may give FOCs different abilities to pass on external cost increases (such as higher track access charges) to their end customers. Regardless of the formal contractual position, it is possible that a FOC might make a deliberate decision to absorb some of the extra cost if it thought that a particular long distance flow was in danger of being withdrawn (especially if the contract for transporting coal from an alternative source might go to a competing FOC). And it is possible that a FOC might decide to absorb some of the cost increase in an attempt either to maintain or to increase its market share;

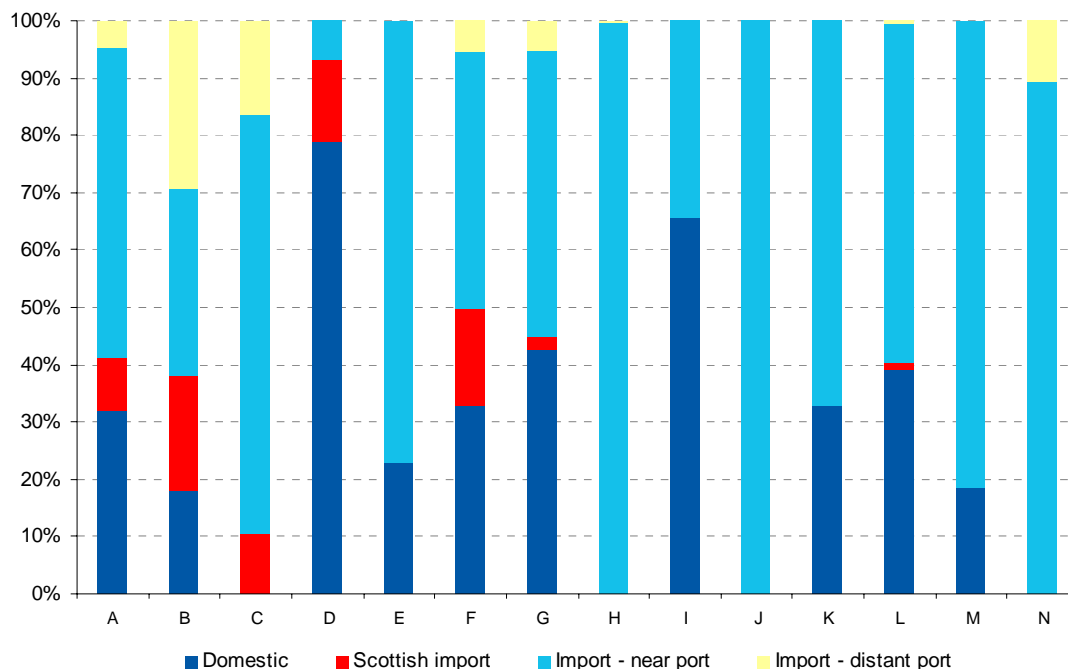
In addition, generators might choose to change their coal sourcing and/or transport decisions in order to reduce their reliance on coal flows that are particularly strongly affected by higher track access charges. This might lead English power stations, for example, to consider a switch from Scottish coal to imported coal if it can be delivered through a nearby port, and also to review any cases where imports are not routed through the nearest suitable port.

Either of these types of change would result in less than the full increase in track access charges being passed on to generators, and would therefore moderate the likely impact on total ESI coal demand. However, there is an important difference, because changes in coal sourcing or transport decisions could also lead to significant reductions in the distance that coal is transported by rail. Even if the reduction in freight volumes lifted (ie net tonnes) is relatively small, there could be a large reduction in the volume of freight moved (ie net tonne kms). The sensitivity test described in Section 3.3.2 illustrates the potential impact that such changes could make.

Figure 2.10 summarises the proportion of coal transported by rail to individual power stations in the year to September 2011.²⁹ This shows that there are substantial differences between power stations in their sources of coal (though not visible in the chart, in some cases there are differences between the coal sources used by power stations that are close to each other). Much imported coal is now transported through major ports (such as Immingham, Liverpool and Bristol for English power stations, and Hunterston for Scottish power stations) that are among the most suitable in terms of minimising distances travelled. And there are five main English power stations that source a significant proportion (between 10 and 20 per cent) of their coal from Scottish open cast mines.

²⁹ Proportions are measured by tonnes (rather than tonne kms). “Domestic coal” is defined as coal sourced from the country (ie England, Scotland or Wales) in which the power station is located. “Scottish imports” refers to Scottish coal used by English power stations. “Distant” ports are defined on a case-by-case basis for each power station (in practice there is usually a clear break point between one or more ports that are closest to each power station and those that are a significantly greater distance away).

**Figure 2.10
Coal Sourced in 2010/11**



With the sourcing decisions summarised in Figure 2.10, in the year to September 2011 ESI coal travelled an average distance of 153 kms by rail. If the coal imported through distant ports was switched to nearby ports, this would reduce the average distance travelled by rail to 136 kms. And if Scottish imports were also eliminated (and replaced by imports through nearby ports), this would reduce the average distance travelled to 109 kms.

It is possible that some further rationalisation of port usage could occur before 2014, regardless of decisions on future track access charges. If some distant ports are used at present simply because there is insufficient capacity at closer ports to cope with current demand, then such problems might be lessened if the total demand for ESI coal is lower in future (which we expect will be the case - see Section 3.1 - though the impact on traffic at particular ports will depend on how the reduction in demand is distributed between power stations). Clearly, if further rationalisation of port usage occurs before April 2014, then there will be less risk that increases in track access charges will lead to a significant further reduction in the average distance that coal travels by rail to each power station.

3. Estimated Impact on Demand

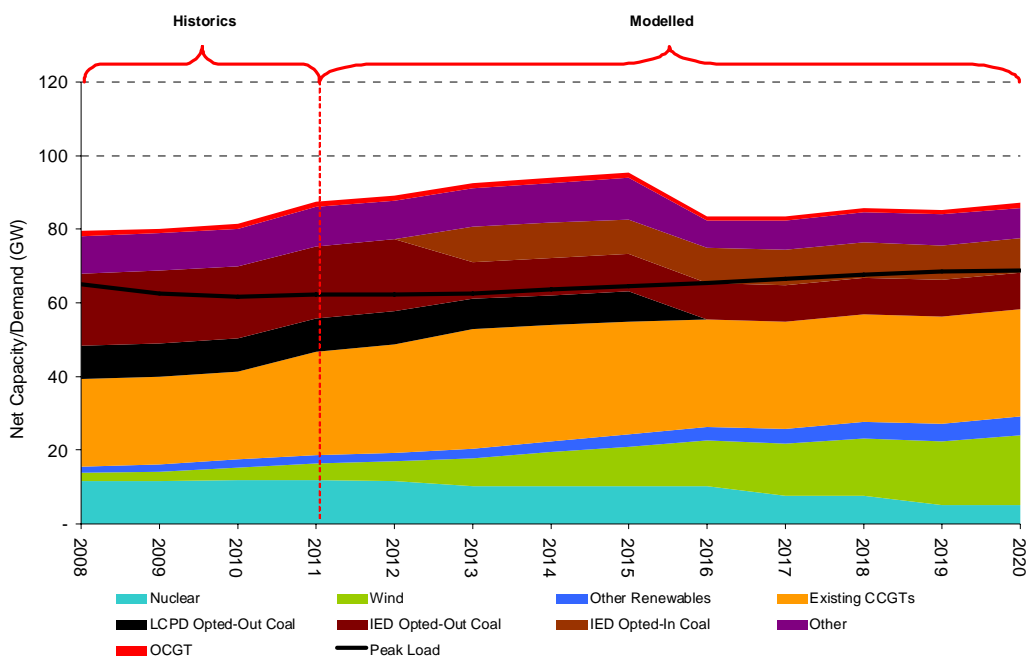
3.1. Base Case Forecasts

In this section, we consider the likely ESI demand for coal at the current level of track access charges.

Figure 3.1 shows our projected mix of installed capacity on the GB power system, as compared to peak demand. It shows that by 2015 all LCPD opted-out coal plants will close, reducing the quantity of coal-fired generation on the GB system, as required by the directive. It also shows that in our base case scenario, our model predicts that around half of the remaining coal-fired generation fleet will opt into the IED, and the other half will opt out.³⁰

Offsetting the tightening of the supply-demand balance caused by coal plant closures, we assume that some gas-fired CCGTs that are already under construction will come online by 2013, and that investment in new renewable generation capacity will continue, in line with government targets.³¹ Our model does not predict any investment in new non-renewable generation capacity over the period to 2020, other than that which is already under construction.

Figure 3.1
Installed Capacity vs. Peak Demand (no change in track access charges)



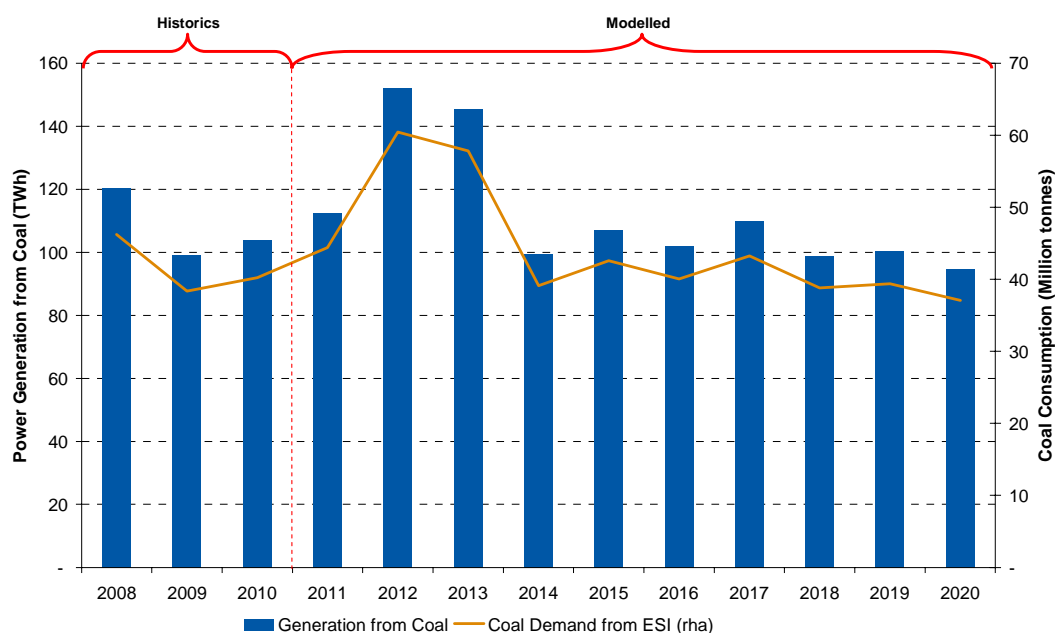
³⁰ As described above in Section 2.6.4, our model optimises each plant’s decision over whether to opt in to the IED, or opt out and accept limited running hours.

³¹ Note, reflecting the delays typically experienced by renewables developers, we assume that the government’s target of sourcing 30 per cent of generation from renewables will be achieved with a delay of five years.

Figure 3.2 shows our base case projection of ESI coal demand. Between 2011 and 2012, the model indicates an increase in generation from coal caused by an increase in the gas price and a reduction in the CO2 price. Both effects improve the position of coal plants in the merit order relative to gas plants, as shown in Figure 2.8.

Between 2013 and 2014, however, coal generation falls due to the impact of the CPF, the closure of some coal plants that have opted-out of the LCPD, and new CCGT and renewable generators coming on stream. These effects all worsen the position of coal plants in the merit order relative to gas. Hence, even assuming no change in track access charges, our model predicts that by 2014 coal-fired generation output, and hence ESI coal demand, will fall back to the levels experienced in 2009 and 2010. After 2014, coal generation fluctuates from year to year, reflecting the net impact of expected increases in gas prices (which improves coal’s position in the merit order) and in the CPF (which worsens it).

Figure 3.2
Coal Generation (TWh) and Coal Demand (t) (no change in track access charges)



Source: NERA Analysis. Historical generation and coal demand data from DUKES (DECC) 2010³²

The main purpose of these base case projections, generated using our detailed bottom-up model of the power market, is to provide a starting point for assessing the impact on coal demand following changes in certain fundamental assumptions. Hence, Figure 3.2 does not necessarily present a central forecast of ESI coal demand, and any such forecast would be highly sensitive to changes in commodity prices and other changes in market conditions. The sensitivity test described in Section 3.3.1 below shows how the starting point (ie before

³² http://www.decc.gov.uk/en/content/cms/statistics/energy_stats/source/electricity/electricity.aspx

taking account of any increase in track access charges) may be significantly affected by different assumptions about the relative prices of coal and gas.

3.2. Impact of Increased Access Charges

As noted above, ORR asked us to examine the impact of six different access charging options over the duration of the next control period (“CP5” – the five years from April 2014).³³ From a situation where the average track access charge for ESI coal traffic is equivalent to £2.25 per thousand net tonne kms (plus a freight-only line charge of just over 60p per thousand net tonne kms), we have estimated the impact of:

- as the “central” option, an increase equivalent to £10 per thousand net tonne kms,³⁴ and alternative increases of £5 and £15 per thousand net tonne kms; and
- a “revenue neutral” variant on the £10 increase that, absent any change in volumes or routes, would generate the same total revenues but where only half of the increase is distance-related. This is an increase of £0.765 per net tonne plus £5 per thousand net tonne kms.

For these model runs, we have assumed that all of the cost increase is passed on in full to generators, and that the proportions of coal that each power station sources from and transports via different routes remain unchanged. Thus the increase in the delivered price of coal at each power station is simply the increase in track access charge (per net tonne km) multiplied by the average distance coal travels to that power station.

3.2.1. The impact on ESI coal demand

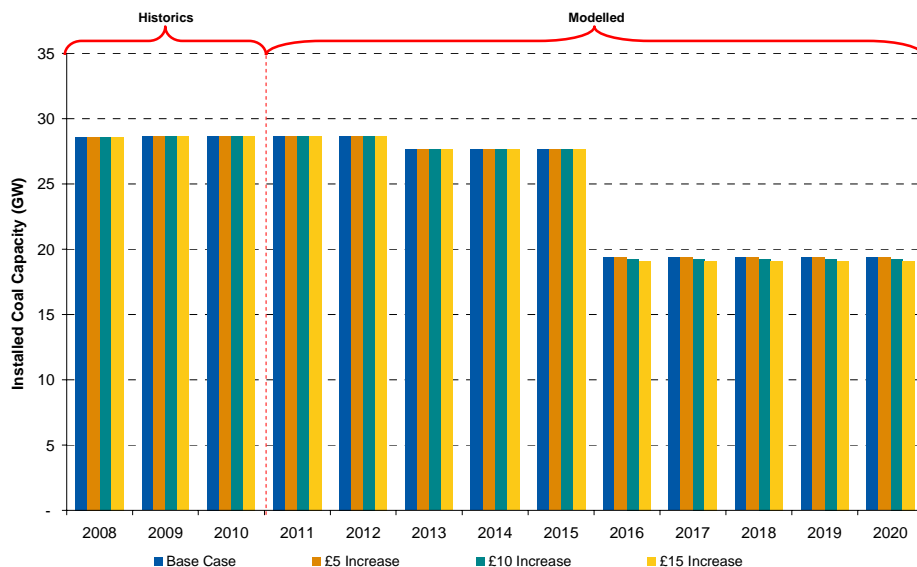
Figure 3.3 shows that across the scenarios where we increase freight track access charges by between £5 and £15 per thousand net tonne km, we see only a minor impact on the quantity of coal-fired generation capacity installed on the system in the period to 2020. Hence, the increase is not sufficient to force any significant early closure of the existing fleet of coal-fired generators, as compared to the base case.³⁵

³³ For simplicity and ease of interpretation, we have modelled an increase in track access charges that applies from January 2014.

³⁴ In practice, if this or another option were implemented, the increase would be introduced as a change in the access charge per gross tonne mile.

³⁵ As noted above in Section 2.5, our model represents each GB coal plant as a separate entity, and it simulates separate decisions regarding the timing of closure for each of these plants.

Figure 3.3
Impact of TAC increases on Installed Capacity

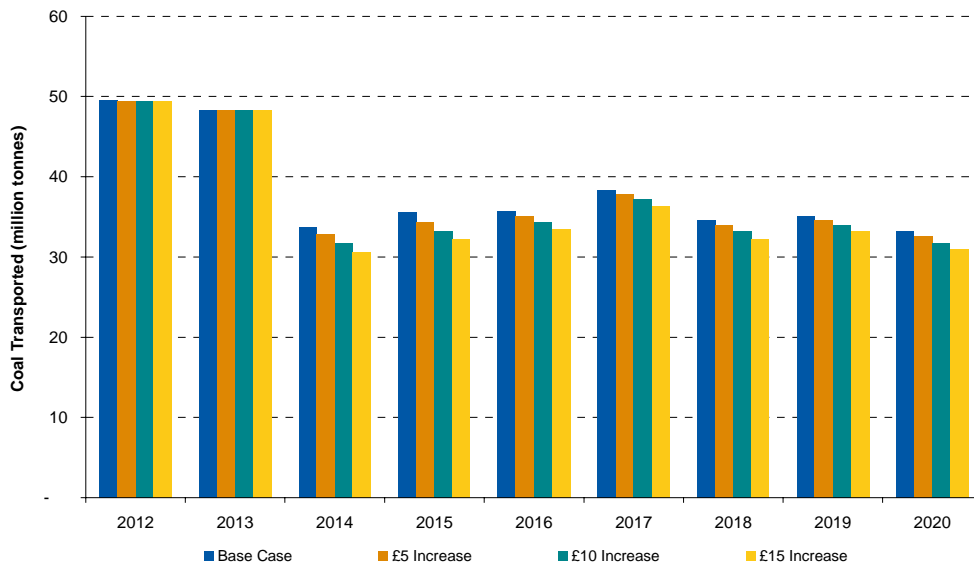


Source: NERA Analysis

However, Figure 3.4 shows that the impact on demand for ESI coal, as measured by coal lifted, is proportionately larger, indicating that the coal-fired generation that remains on the system runs less frequently than in the base case. The change in coal moved (tonne kms) is somewhat larger, as Figure 3.5 shows, as the impact on demand is highest for those coal stations that source coal from more distant locations (for these model runs we have assumed there is no change in the proportions of coal that each power station obtains from different sources).

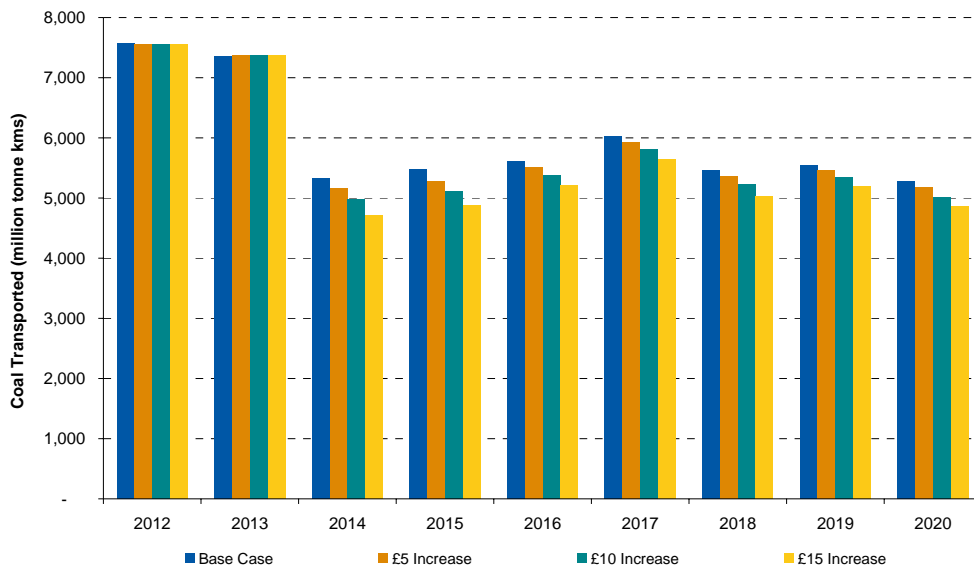
As Table 3.1 illustrates, over the period between 2014 and 2018, which approximately corresponds to the upcoming control period, coal lifted falls by 4.6 per cent and coal moved falls by 5 per cent following the central case increase in access charges of £10 per thousand net tonne km, as compared to the base case assumption of £2.25.

Figure 3.4
Impact of TAC increases on Coal Lifted



Source: NERA Analysis

Figure 3.5
Impact of TAC increases on Coal Moved



Source: NERA Analysis

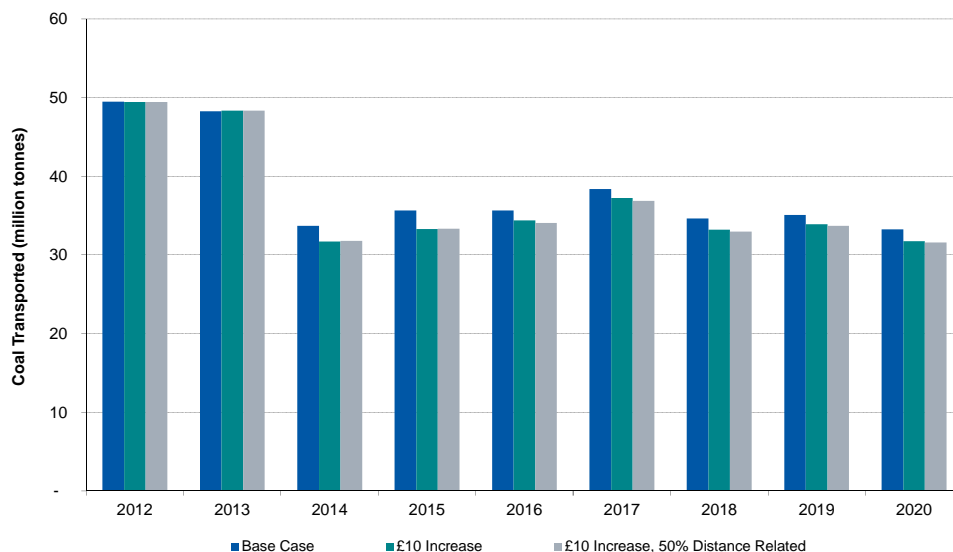
**Table 3.1
Overall Impact on Coal Transportation (2014-18)**

	Coal Lifted		Coal Moved	
	<i>million tonnes</i>	<i>% Change</i>	<i>million tonne kms</i>	<i>% Change</i>
Base Case	178	0.0%	27,889	0.0%
£5 Increase	174	-2.1%	27,221	-2.4%
£10 Increase	170	-4.6%	26,501	-5.0%
£15 Increase	165	-7.4%	25,466	-8.7%

Source: NERA Analysis

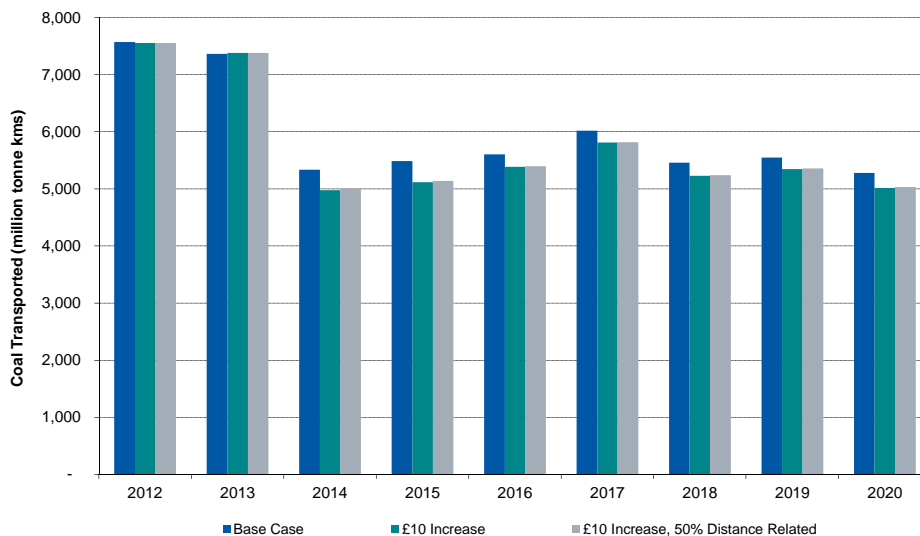
In the “revenue neutral” variant, we find a very slightly higher impact on coal lifted as compared with the case where the whole £10 increase is distance related, as Figure 3.6 shows. However, the impact on coal moved is somewhat less, as Figure 3.7 illustrates. Table 3.2 shows that coal lifted falls by 5.1 per cent, and coal moved falls by 4.7 per cent if the £10 increase is only partly distance-related.

**Figure 3.6
Impact of TAC increases on Coal Lifted**



Source: NERA Analysis

Figure 3.7
Impact of TAC increases on Coal Moved



Source: NERA Analysis

Table 3.2
Overall Impact on Coal Transportation (2014-18)

	Coal Lifted		Coal Moved	
	million tonnes	% Change	million tonne kms	% Change
Base Case	178	0.0%	27,889	0.0%
£10 Increase, 50% Distance Related	169	-5.1%	26,584	-4.7%

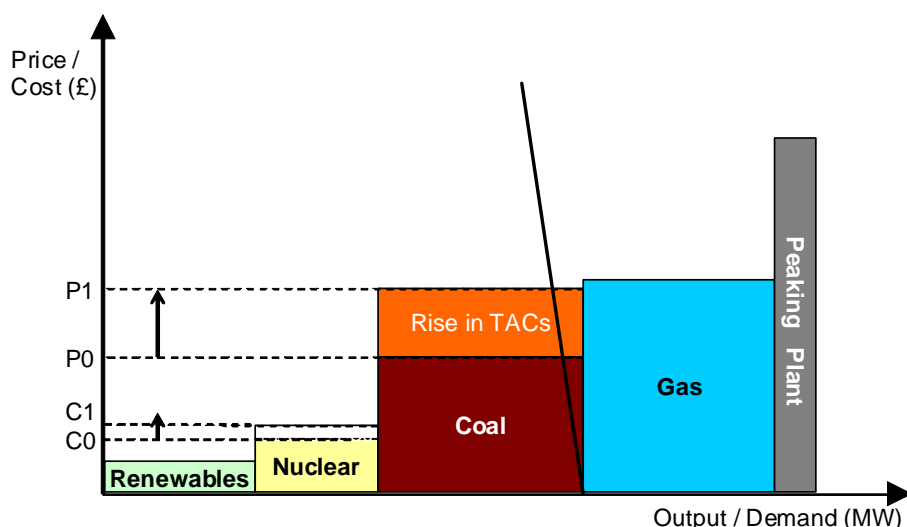
Source: NERA Analysis

3.2.2. Impact of a change to nuclear charges

As Figure 3.8 illustrates schematically, nuclear plants have a very low *marginal* cost of production. Hence, they run whenever they are technically capable of doing so, i.e. when they are not undergoing a planned or forced outage.³⁶ In other words, nuclear plants are always “inframarginal”, so they sell their output at the wholesale electricity price, which is usually set by coal or gas-fired generators. Moreover, track access charges levied on nuclear traffic account for a very limited share of the overall variable costs of a nuclear plant. Even a very significant increase in £/t of nuclear fuel transported would make a very small difference to the variable/marginal cost of generation.

³⁶ Additionally, it is often argued that nuclear plants do not have the flexibility to change generation output, so the avoidable cost of scaling down generation, i.e. the short-run marginal cost of dispatch, may therefore effectively be negative.

Figure 3.8
Impact of TAC increase on Nuclear



Source: NERA Analysis

These two effects combined mean that the elasticity of demand for the transport of nuclear fuel with respect to changes in track access charges is likely to be very limited. We have confirmed this by running a scenario where we increase freight track access charges faced by nuclear generators by £100 per thousand net tonne km. Rather than a realistic policy option, this was simply designed to test the proposition that the demand elasticity for nuclear fuel with respect to track access charges is very low.

We have found that even such a high increase has no impact whatsoever on the predicted demand for, or transport of, nuclear fuel in the short and medium term. We also note that nuclear has effectively no option of substitution of mode of transport due to safety concerns, which makes transportation demand for nuclear fuel very inelastic. However, in the longer term there may be effects related to nuclear decommissioning or life-extensions due to the impact of freight access charges on the overall profitability of nuclear plants.

On the other hand, as Figure 3.8 shows, increasing track access charges to coal plants, and the resulting impact on the power price, will increase the revenues earned by nuclear generators from sales into the power market, which will offset at least to some extent any increase in costs nuclear plants face due to increases in their own track access charges. In practice, this effect means that nuclear plants may *benefit* from industry-wide increases in track access charges, as our modelling indicates their margins increase by up to 0.9 per cent, depending on the scenario, as Table 3.3 shows.

**Table 3.3
Change in Nuclear Plant Margins vs. Baseline (2014-18)**

Change in Nuclear Margins vs. Baseline	
<i>% Change, Undiscounted Margins</i>	
£5 Increase	0.3%
£10 Increase	0.6%
£15 Increase	0.9%

Source: NERA analysis. Note, margins are defined as power market revenue, less variable costs of production, including fuel commodity and transport costs.

3.2.3. Impact of a change to biomass charges

3.2.3.1. The use of biomass in power generation

Biomass includes a range of fuels, including landfill gas, sewerage gas, waste combustion, animal and plant biomass products, liquid biofuels, and wood pellets.³⁷ Biomass is widely classified as a renewable energy source. As such, biomass plants do not pay for their emissions of CO₂. Even so, the costs of producing electricity using biomass is often substantially higher (on a £ per MWh basis) than the costs of using fossil fuels such as coal.

Because the UK has a legally binding target under the EU Renewable Energy Directive to increase the share of renewables in final energy consumption, the UK government subsidises power generators that use biomass through the Renewables Obligation (RO) scheme. For every MWh of output they produce using biomass, power generators are awarded Renewables Obligation Certificates (ROCs). Generators can sell ROCs to electricity suppliers, who buy them to comply with their obligation to present a certain number of ROCs to Ofgem each year.³⁸ Hence, the RO provides additional revenue to renewable generators, which is paid for initially by suppliers and ultimately by electricity users.

3.2.3.2. The impact on biomass demand

At present, biomass is largely used in power generation in coal-fired power stations through “co-firing”, whereby a small quantity of wood pellets or other forms of biomass are blended with coal in the combustion process. In this process, biomass usually makes up only a small proportion of fuel burned.³⁹ The change in demand for biomass for use in co-firing following an increase in track access charges is therefore determined largely by the impact on demand for coal, which we assess in Chapter 3.

However, the precise impact will depend on the way that the increase in track access charges is calculated. Biomass has a lower calorific value than coal, which means a larger amount of

³⁷ Digest of UK Energy Statistics, Table 7.1.

³⁸ If electricity suppliers present too few ROCs as compared with their obligations, they must pay a “buy-out” on a £/ROC basis.

³⁹ Even Drax, which we understand co-fired more biomass than other coal plants on the GB system, is only capable of co-firing using 12.5% biomass and 87.5% coal. (Source: Drax website, visited on 28 March 2012, URL: http://www.draxpower.com/biomass/cofiring_plans/)

biomass (in tonnes) needs to be transported to power stations for every unit of energy produced than if the same unit of energy were produced using coal. And its different mass means that the relationship between net and gross tonne kms will be different from that for coal. As a result:

- if the increase in track access charges for biomass is calculated so that it has the same impact on generation costs (ie £ per MWh) as the increase in charges for coal traffic, then the impact on the ESI's demand for biomass for co-firing should be the same as the impact on its demand for coal; or
- if track access charges for biomass increase by the same amount per net or gross tonne km as track access charges for coal, then we would expect generators to reduce the proportion of biomass that they use and therefore the ESI's demand for biomass for co-firing might fall by more than our modelled reduction in demand for coal.

For dedicated biomass facilities, the impact on demand from increasing access charges depends on the change in plants' position in the merit order, and their marginal cost as compared to other competing technologies. Like nuclear plants, biomass generators are likely to be high in the merit order, so we would not expect an increase in track access charges to affect the output (and therefore the demand for biomass) of existing facilities. Indeed, the impact of the RO scheme means that dedicated biomass generators' marginal cost of production may be close to zero, or even negative, at present.⁴⁰ However, it is possible that an increase in track access charges could affect decisions about the future development of biomass plants.

Most existing biomass power stations have been developed on a small scale,⁴¹ and so are likely to purchase biomass from their local areas, and making little use of the rail network. In the coming years biomass demand is expected to grow to meet government targets, which may result in the development of large-scale dedicated biomass facilities that consume biomass products more suitable for transport by rail, such as imported wood chips. However, at present there is considerable uncertainty over where any new biomass generators will be located, or the extent to which they will rely on the rail network. For instance, a number of new biomass generation projects have been proposed near to ports, whereas others are inland, and so some of these would rely on rail transport to a greater extent than others. An increase in track access charges, therefore, might make inland locations relatively less attractive compared with locations near to ports.

⁴⁰ For example, a recent study by Mott MacDonald for DECC estimates that the variable cost of biomass generation is between £22/MWh and £41/MWh. Under recent DECC proposals, new dedicated biomass generators will receive 1 ROC/MWh. At the current market price for ROCs of £42/ROC, the net cost of generating a unit of electricity is negative, between -£1/MWh and -£20/MWh.

Sources: (1) UK Electricity Generation Costs Update, Mott MacDonald, June 2010, Table C.2; (2) Consultation on the Renewables Obligation Banding Review, Department for Energy and Climate Change, October 2011, page 26; (3) ROC market price based on results of the "e-roc" auction from 24 February 2012 – see <http://www.e-roc.co.uk/trackrecord.htm>.

⁴¹ For example, the "Platts Powervision" database, which contains data on GB power plants, lists only 7 operating dedicated biomass plants, all of which have capacity below 50MW. In contrast, most coal-fired generators in GB have capacities of 1,000MW or more.

The impact on demand for biomass, by both dedicated biomass plants and coal plants that use biomass for co-firing, is further complicated because the total effect will depend on the response of government to changes in the cost of generation using biomass. When setting biomass subsidy levels, the government aims to provide sufficient payment to generators to enable its targets to be met, while also minimising the additional costs placed on electricity consumers from providing subsidy revenues to renewable generators in excess of their costs. The government therefore accounts for the costs of generating electricity using biomass when setting subsidy levels.⁴² Hence, if biomass generators' fuel costs increase, they may benefit from an offsetting increase in subsidy payments that the government would need to offer in order to achieve its targets, albeit possibly with a lag as the government only reviews subsidy levels periodically.⁴³ If higher subsidies compensate biomass generators for an increase in access charges, demand for ESI biomass would be unchanged. However, any delay in adjustment means increasing access charges could still affect demand for a period.

Ultimately, therefore, the future demand for biomass from the ESI will depend on government policy regarding renewables subsidies, which it sets taking account of the costs of competing renewables technologies, as well as other factors such as its desire to meet renewable energy targets using a range of generation technologies.

3.2.3.3. The impact on subsidies

Although the uncertainties surrounding the location of new biomass stations means it is difficult to predict the precise effect of an increase in track access charges, we have conducted some simple calculations to illustrate the magnitude of the impact.

Assuming that biomass is transported, on average, 100 kms by rail, we estimate that an increase in access charges of £10 per thousand net tonne kms would increase the variable cost of biomass generation by around £0.6/MWh.⁴⁴ While this will not affect biomass generators' output, for the reasons set out above, our modelling suggests they will earn higher revenues from the power market due to the impact on prices from coal generators' increased variable costs. We estimate that they would earn an extra £0.3/MWh of revenue on average between 2014 and 2018.

The difference between the change in costs and revenues (£0.6/MWh - £0.3/MWh = £0.3/MWh) will manifest itself as either lower margins for biomass generators, or as a requirement for additional subsidies to maintain the profitability of new biomass plants. Assuming 3,900MW of new biomass capacity comes online by 2020,⁴⁵ an increased subsidy

⁴² Energy Act 2008, Section 32D, paragraph 4(a).

⁴³ The government is in the process of fixing subsidies for existing biomass plants through the "Renewables Obligation Banding Review" for the period from 2013-2017. However, new biomass generators may have the option of receiving subsidies under a new mechanism, proposed as part of the government's Electricity Market Reform process, that will replace the Renewables Obligation around the period 2014/15.

⁴⁴ This calculation assumes an HHV (net) calorific value for biomass of 16.5 GJ/tonne (based on the PIX Pellet Nordic Industrial Index Specification, see www.foex.fi), and that biomass generators have a sent-out HHV efficiency of 35%.

⁴⁵ Our calculations using data from the Government's 2011 "Renewable Energy Roadmap" suggest that, in a central case, the Government's projections imply around 3,900MW of new dedicated biomass generation capacity by 2020. Source: UK Renewable Energy Roadmap, Department for Energy and Climate Change, July 2011, page 67. This calculation assumes biomass generators run at an 80 per cent load factor.

requirement of £0.3/MWh would increase costs to customers by around £8 million per year which we estimate would increase residential electricity bills by around 0.02 per cent.

The increase in biomass generation costs (and therefore subsidy requirements) would be lower, however, if the increase in track access charges was less than £10 per thousand net tonne miles. One reason for a lower increase would be to ensure that the impact on generation costs (per MWh) is the same for biomass as for coal.

3.3. Sensitivity Tests

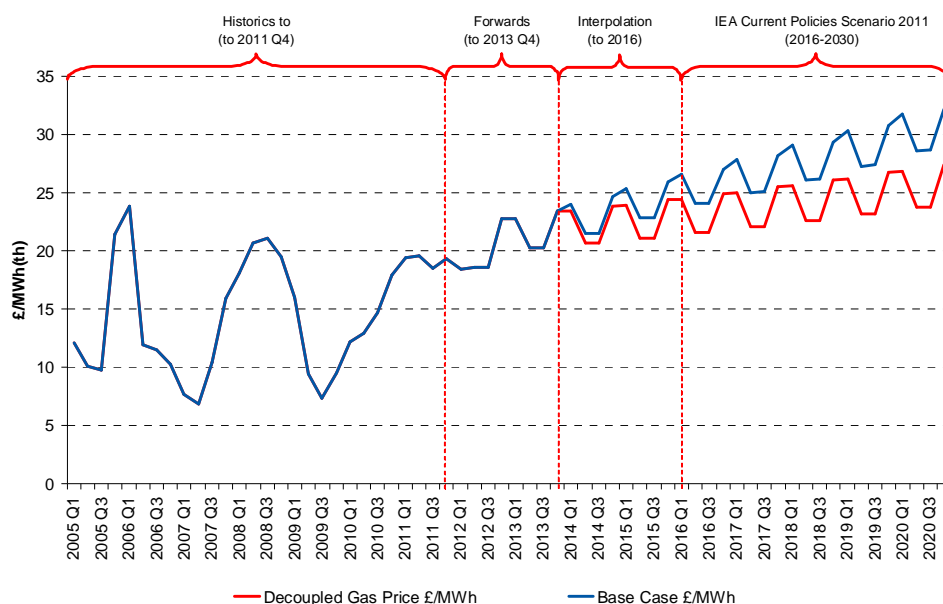
3.3.1. Low gas price scenario

The IEA's 2011 WEO gas price forecast, which underlies our baseline long-term gas price forecast, assumes that EU gas prices will remain at a constant ratio to the oil price over the period to 2030. This reflects an assumption that oil indexation will continue to dominate gas pricing in Europe for the coming years.

However, this assumption is subject to some uncertainty. For instance, in 2009/10 a surplus of upstream gas and LNG capacity caused a "decoupling" of gas and oil prices in Europe due to a surplus of upstream supplies. This "decoupling" may be repeated in future due, for example, to the further development of competition in downstream gas markets, expansion of global LNG trade, or the gradual discovery of shale gas supplies in Europe.

To reflect this uncertainty, we considered a low gas price scenario in which European gas prices remain constant in real terms from the end of the liquid forward curve, as shown in Figure 3.9.

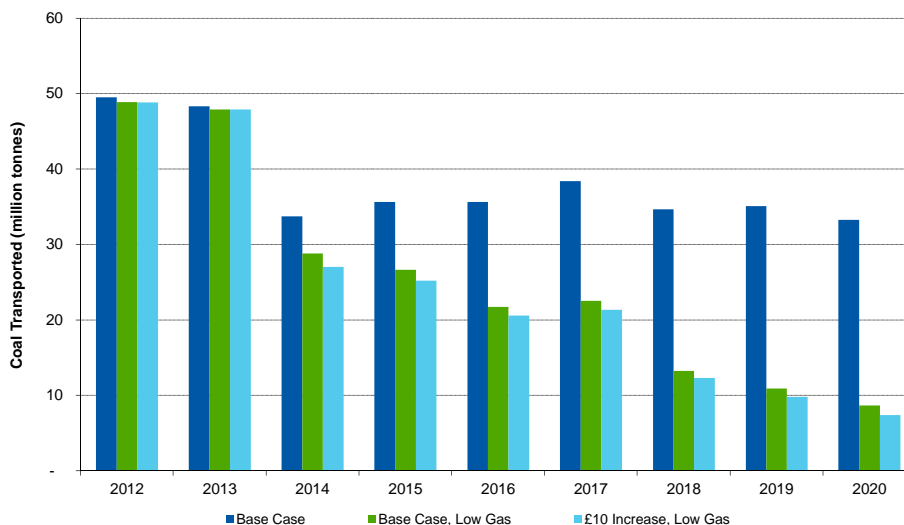
**Figure 3.9
Low Gas Price Sensivity Scenario**



Source: NERA Analysis

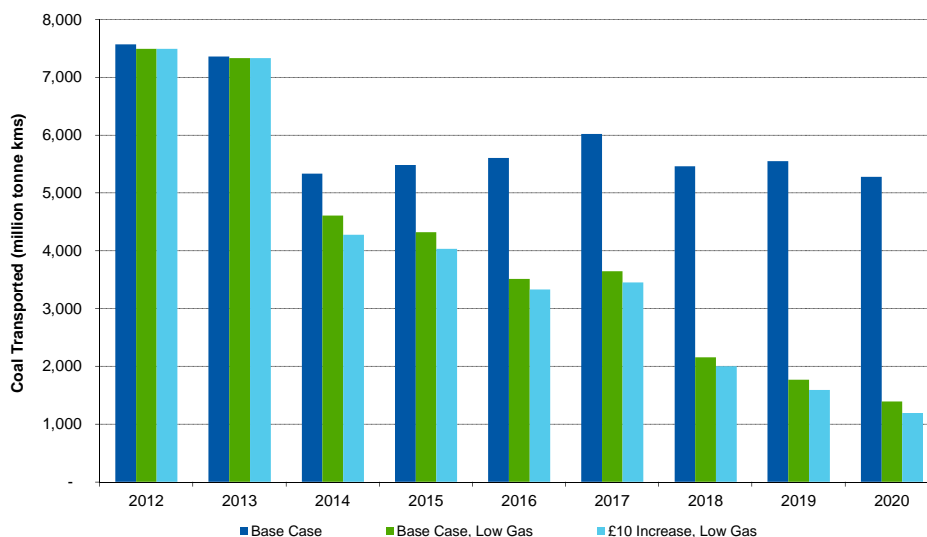
As the figures below illustrate, the low gas price sensitivity significantly reduces coal demand by more than 50 per cent relative to the base case. The figures also show that the central case increase in track access charges (£10 per thousand net tonne km) reduces coal lifted and moved by around 6 per cent, which is only a slightly larger proportional reduction than in the central case runs with the higher gas price.

**Figure 3.10
Coal Lifted - Central Case, Low Gas Price Sensivity**



Source: NERA Analysis

Figure 3.11
Coal Moved – Central Case, Low Gas Price Sensitivity



Source: NERA Analysis

Table 3.4
Overall Impact on Coal Transportation (2014-18)

	Coal Lifted		Coal Moved	
	million tonnes	% Change	million tonne kms	% Change
Base Case	178		27,889	
Base Case, Low Gas	113		18,231	
£10 Increase, Low Gas	106	-5.8%	17,083	-6.3%

Source: NERA Analysis

3.3.2. A higher increase

ORR also asked us to examine the impact of an increase in track access charges of £25 per thousand net tonne kms (equivalent to £20 per thousand gross tonne miles). Rather than being a realistic policy option, this is simply designed to test the sensitivity of demand and the presence of tipping points.

Not surprisingly, as Table 3.5 shows, the £25 increase has a larger impact on coal demand than a £10 increase. The proportionate difference between the impacts on both coal lifted and coal moved is slightly larger than the proportionate difference between the £10 and £25 increases, but not by very much. Consistent with Table 3.1 above, this is suggestive of an impact on traffic volumes that gets gradually larger, rather than there being any specific tipping point, at least for increases of up to £25 per thousand net tonne kms.

**Table 3.5
Overall Impact on Coal Transportation (2014-18)**

	Coal Lifted		Coal Moved	
	<i>million tonnes</i>	<i>% Change</i>	<i>million tonne kms</i>	<i>% Change</i>
Base Case	178	0.0%	27,889	0.0%
£10 Increase	170	-4.6%	26,501	-5.0%
£25 Increase	155	-12.6%	23,383	-16.2%

Source: NERA Analysis

3.3.3. Partial pass through of cost increases

In all the scenarios described above, we assume that the increase in track access charges is passed on in full to generators, and that generators do not change their coal sourcing and transport decisions in response to the increase (even though it will affect some flows to a greater extent than others). Section 2.6.5 lists some of the changes that could occur in practice and might insulate generators from some of the impact of higher track access charges. It also identifies the risk that changes to coal sourcing and transport decisions could lead to a larger impact on freight tonne kms.

In order to illustrate the potential size of such impacts, we carried out a sensitivity test based on the central increase of £10 per thousand net tonne kms, but also assuming that:

- Scottish coal producers absorb some of the increase in order to maintain their competitive position relative to imported coal.⁴⁶ As a result, the cost increase faced by generators consuming Scottish coal is the same as that applying to imported coal (routed through a near port);
- generators that currently import coal through distant ports switch this traffic to closer ports in response to higher track access charges.⁴⁷

The combined impact of these changes is to reduce the increase in delivered coal costs by around 30 per cent. However, the change in ports used for coal imports also reduces the average distance that coal travels by more than 10 per cent.

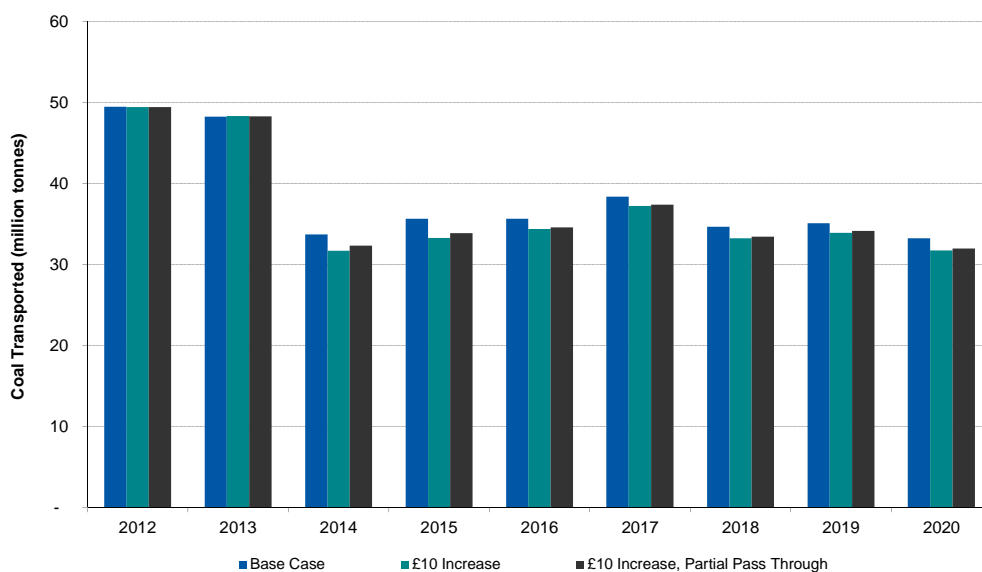
It is difficult to judge the likelihood that these or other changes might occur in practice. As noted in Section 2.6.5, some further rationalisation of transport routes might occur before 2014, in which case the risk of further rationalisation (and therefore a reduction in tonne kms moved, even if tonnes lifted remains the same) would be reduced. If the only change were that Scottish coal producers absorbed some of the increase (ie no change in use of ports), then we would expect both coal moved and coal lifted to fall by around 4 per cent.

⁴⁶ As discussed in Section 4.3, recent history shows that the use of Scottish coal has remained relatively constant, despite large changes in international coal prices.

⁴⁷ It is possible that capacity constraints at some ports are one factor that helps to explain the continued use of distant ports for coal imports. However, the total demand for coal is forecast to fall by 2014, thus reducing the risk that capacity constraints will prevent generators from routing all of their coal imports through the most conveniently located ports.

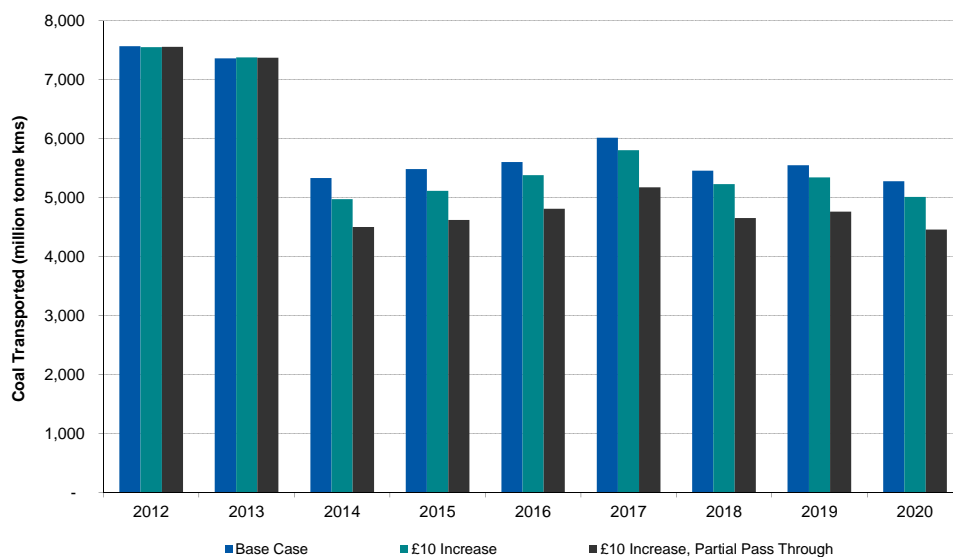
The purpose of this sensitivity test is simply to illustrate how much difference such changes could make to the estimated impact of higher track access charges on rail freight volumes, rather than necessarily describing a specific outcome that we think is likely to occur. As the figures below illustrate, the assumption that increased track access charges are only partially passed through to coal-fired generators reduces the impact on coal lifted due to a £10 per thousand net tonne km increase in freight access charges from 4.6 per cent (see Table 3.1) to 3.6 per cent. However, because coal generators source their fuel from closer ports or mines, we estimate a larger impact on coal transported of 14.8 per cent, relative to 5 per cent in the case where we assume a £10 per thousand tonne km increase in access charges.

**Figure 3.12
Coal Lifted - Central Case, Partial Pass Through**



Source: NERA Analysis

Figure 3.13
Coal Moved - Central Case, Partial Pass Through



Source: NERA Analysis

Table 3.6
Overall Impact on Coal Transportation (2014-18)

	Coal Lifted		Coal Moved	
	million tonnes	% Change	million tonne kms	% Change
Base Case	178		27,889	
£10 Increase, Partial Pass Through	172	-3.6%	23,760	-14.8%

Source: NERA Analysis

4. Wider Impacts

In this section we consider several wider impacts that ORR asked us to address, including the change in electricity bills, the implications for Scottish open cast coal mining, and any impact on current or planned investments. First, however, we briefly report the increase in Network Rail revenues that would result from the main options we have examined

4.1. Impact on Network Rail Revenues

An increase in track access charges could lead to a greater share of Network Rail’s total freight avoidable costs being recovered from train operators and ultimately from end users. This would reduce the amount of subsidy that Network Rail requires from the Department for Transport and Transport Scotland.

To assess the additional contributions that would be generated, we have calculated the net impact of:

- additional payments of £5, £10 or £15 per thousand net tonne kms for the coal traffic that continues running despite the higher level of charges;
- reduced revenues from the freight-only line charge as a result of the estimated reduction in total ESI coal traffic.

We have not taken account of the reduction in Network Rail’s income from variable track access charges, as Network Rail would also be expected to benefit from a similar sized reduction in its variable costs.

Table 4.1 shows the net increase in Network Rail’s revenues from coal traffic in each year. In addition, there would be a small increase in net revenues from nuclear traffic – with a £10 increase this is less than £300,000 per year.

**Table 4.1
Net Increase in Network Rail Revenues**

<i>£ million, 2010-11 prices</i>	2014	2015	2016	2017	2018	Total
Increase of £10 per 1000 net tonne kms	49.5	50.9	53.7	57.9	52.1	264.1
Increase of £5 per 1000 net tonne kms	25.7	26.2	27.5	29.6	26.7	135.7
Increase of £15 per 1000 net tonne kms	70.4	72.7	77.8	84.4	75.1	380.4

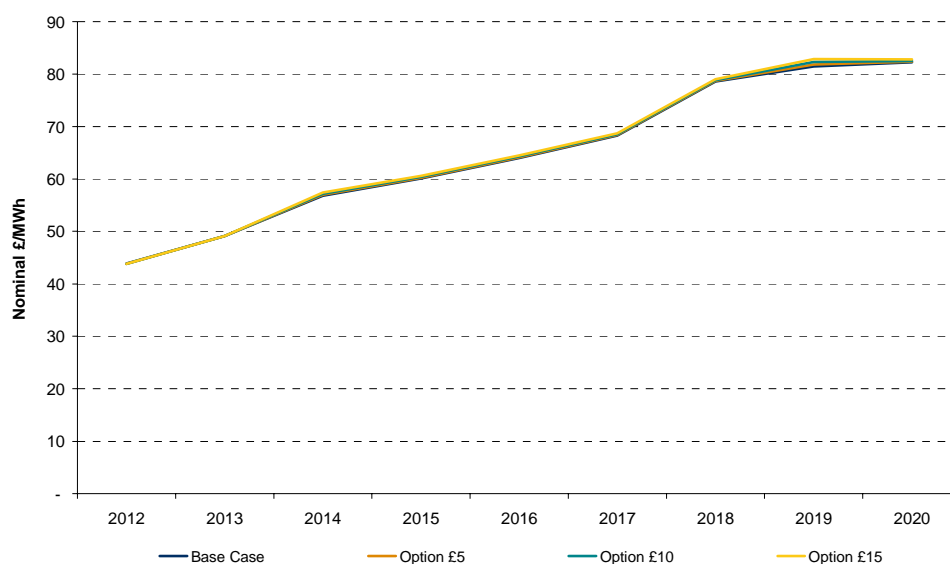
Source: NERA Analysis

4.2. Impact on Electricity Bills

An increase in track access charges can increase electricity bills, because when coal plants are on the margin, power prices will reflect their increased short run marginal cost of production. This increases the price that electricity retailers pay to procure power to serve end users, which raises customer bills.

Figure 4.1 shows that the increase in the demand-weighted wholesale electricity price⁴⁸ under the £5-£15 charging options is extremely small.⁴⁹ The average increase following a £10 per thousand net tonne km in access charges is about 0.5 per cent over the period 2015-2020, although the impact varies slightly from year-to-year. This percentage change in the costs of purchasing electricity on the wholesale market will tend to overstate the proportional impact on end-users' bills because customers also pay for other costs, such as network charges and supply costs, which are not included in wholesale prices. Hence, we would expect most end-users' bills to increase by less than 0.5 per cent on average under the central case increase in access charges.⁵⁰

**Figure 4.1
Wholesale Power Prices (£/MWh)**



Source: NERA Analysis

4.2.1. Impact on domestic customers' bills

As shown in Table 4.2, we estimate that an increase of 0.5 per cent in the demand weighted wholesale electricity price implies an increase in a typical domestic customers' annual bill of around 0.2 per cent, or less than £1 per year.⁵¹

⁴⁸ This is defined as the annual average of hourly prices over the course of the year, weighted according to the level of demand in each hour.

⁴⁹ The alternative charging options have a similar impact on prices so are not shown.

⁵⁰ Additionally, as described above, customer bills may also increase following an increase in track access charges because of the additional cost of subsidising biomass power stations.

⁵¹ In this calculation, we have assumed the increase in wholesale market costs to serve domestic users is determined by the increase in the demand weighted electricity price. This is consistent with domestic customers' tendency to consume more electricity during the peak hours than off-peak hours.

Table 4.2
Illustrative Impact on Domestic Electricity Bills of 0.5 per cent increase
(Domestic Direct Debit customer)

Item	Units	Pre Price Rise	Post Price Rise	Increase
Variable Cost	pence/kWh	10.98	11.01	0.23%
...Of which Energy	pence/kWh	5.00	5.03	0.50%
Fixed Cost	£/Year	35.98	35.98	0.00%
Total Bill	£/Year	398.36	399.18	0.21%

Source: NERA Analysis on data from DECC, Average variable unit costs and fixed costs for electricity in 2010 for selected towns and cities in the UK (QEP 2.2.4).⁵² Assuming annual consumption of 3,300 kWh per year.

4.2.2. Impact on other customers' bills

Due to the variety of large electricity consumers it is difficult to assess the impact on a typical large customer. While the impact on a typical small retail unit might be similar to the impact on a household, large industrial or commercial facilities may have quite different power purchasing arrangements, related to their different consumption patterns and the voltage level at which they connect to the electricity network. The impact of the increase in track access charges on these other types of customers (commercial, industrial) therefore depends on a range of factors specific to each company, and in particular at what time of year the customer consumes electricity (i.e. peak or off-peak).

Small business and residential electricity customers typically consume most power during “peak” periods, so as described above we can examine changes in the demand-weighted power price to assess the likely impact on these customers. In contrast, industrial customers often have flatter consumption profiles than average, i.e. they consume a similar quantity of electricity at all times of the year, and at all times of day. In principle, large industrial customers who use electricity in off-peak periods, when prices are more likely to be set by the marginal cost of coal-fired generation, may be hit harder by the increase than the average customer in some years.

To assess the impact on industrial customers, we examined changes in the “baseload” power price, which assumes a flat profile of consumption over the year. As shown in Table 4.3, we find no strong evidence to suggest that the impact of increased track access charges is larger for customers with a flat consumption profile (as measured by the baseload price) than for customers who consume more power in peak periods (as measured by the demand weighted price). Therefore, we would expect the increase in energy costs for industrial customers to be very similar to that shown above for residential customers.

Table 4.3
Energy Cost Increase (Baseload vs. Weighted customer), £10 option

	Average	2014	2015	2016	2017	2018	2019	2020
Demand Weighted Price	0.5%	0.7%	0.5%	0.4%	0.4%	0.3%	1.0%	0.4%
Baseload	0.5%	0.7%	0.6%	0.5%	0.4%	0.4%	0.9%	0.4%

Source: NERA Analysis

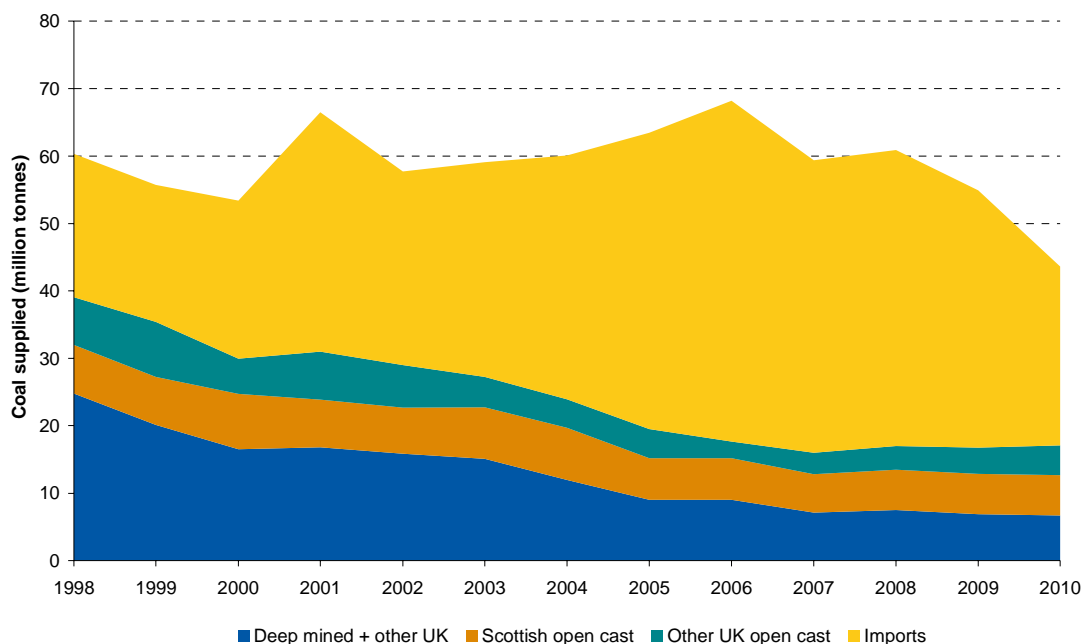
⁵² http://www.decc.gov.uk/en/content/cms/statistics/energy_stats/prices/prices.aspx#domestic

4.3. Scottish Open Cast Coal

Scottish open cast mines currently produce around six million tonnes of coal per year, most of which is used by power stations in either Scotland (notably Longannet) or England. After a steady increase during the late 1980s and early 1990s, production has remained between six million and eight million tonnes a year for most of the last 15 years. As the life of each open cast site is relatively short, this has required the development of a number of new sites, and we understand that further suitable sites have been identified and are at different stages of planning and development.

Currently, coal from Scottish open cast mines accounts for approximately one third of UK production. As shown in Figure 4.2, UK production from deep mines and open cast mines has followed a relatively smooth pattern over recent years, with fluctuations in total demand met by imports which have therefore varied quite significantly from year to year. The UK exports only a small quantity of coal, which has remained relatively constant over the last ten years.

Figure 4.2
Coal Supplied to UK



Source: NERA analysis of data published by DECC and BGS

Significantly, this relative stability of UK and Scottish production has continued despite the large changes in international coal prices shown in Figure 2.5 above. This is indicative, at least, of a situation in which UK producers are able to sell the coal they extract to power stations and other UK users, with imports making up the difference between total demand and domestic supply.

An increase in track access charges could lead to higher than average cost increases for Scottish coal supplied to English power stations. The average distance travelled by Scottish coal to English power stations is nearly 450 kms, whereas the average distance travelled by coal imported through nearby ports to the same power stations is just over 100 kms. If an increase in track access charges of £10 per thousand net tonne kms is passed on to these generators, the cost of Scottish coal will increase by nearly £4.50 per tonne, as compared with just over £1.00 per tonne for coal imported through nearby ports.

In the short to medium term, at least, we would expect Scottish coal producers to absorb as much of this additional cost increase as is necessary in order to continue to sell coal to English power stations. Two reasons for this are that:

- even with a £10 increase in track access charges, the impact on the delivered cost of Scottish coal is still relatively small compared with the changes in international coal prices shown in Figure 2.5. We also note that prices are expected to remain around current levels, which are significantly higher than the level of prices observed 5-7 years ago; and
- in any case, for existing open cast sites, continued extraction is likely to be worthwhile even at lower prices. In the case of a significant price reduction, there may be certain parts of existing sites that become uneconomic. But once a site has been developed and is operational, for the most part it will be worthwhile for extraction to continue even if prices are somewhat lower than expected.

There is probably a greater risk that increased track access charges could affect decisions about whether and when to develop future open cast locations that are next in the pipeline. In addition, however, we note that not all of the output of Scottish open cast mines is sold to power stations in England. Some is sold to power stations in Scotland, and we would expect this situation to continue in future (notwithstanding the closure of Cockenzie power station, which is already reflected in the modelling results reported above). This traffic will be less affected by any increase in track access charges.

4.4. Current and Planned Investment

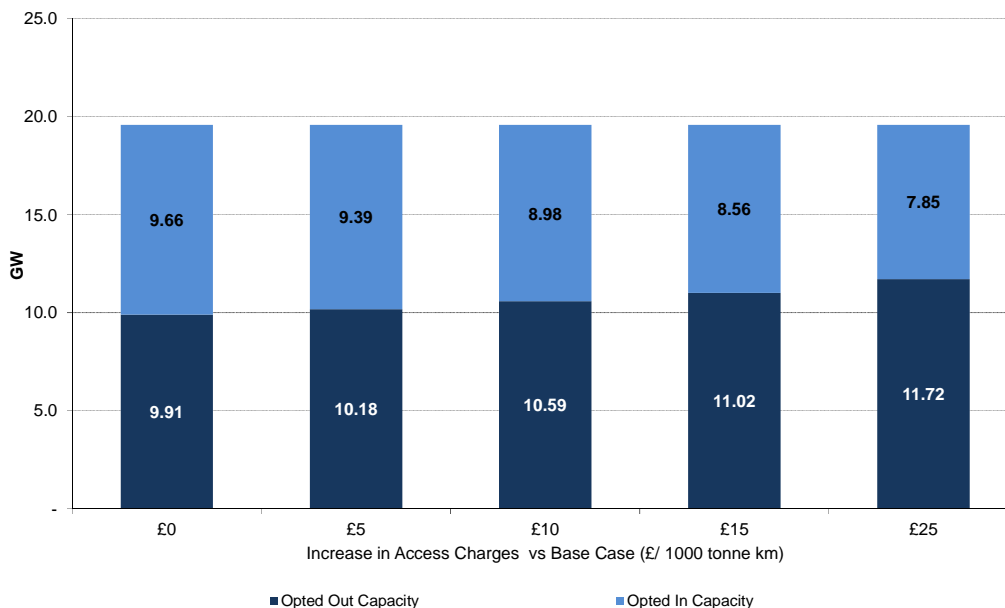
4.4.1. Investments by electricity generators

The main way that higher track access charges are likely to affect investment decisions by coal-fired generators is through their choice of whether to opt in or out of the IED. As described above, coal fired generators currently face a choice regarding whether to opt-in or opt-out of the IED. If they opt-in, they will need to make significant investments in SCR equipment to reduce their NOx emissions. As described above in Section 2.6.4, our model optimises coal-fired generators' opt-in/opt-out decisions endogenously. As Figure 4.3 illustrates, the range of charging options considered in this study (up to £25 per thousand net tonne km) reduces the quantity of coal capacity that our model predicts will opt into the IED by up to 2GW.

As described above, potential investments to develop new biomass fired generators, or to allow more extensive use of biomass at existing coal-fired stations may be affected by an increase in the cost of transporting biomass by rail. However, the extent of this effect will

depend on the response of government to the change when setting subsidy levels, and hence cannot be assessed objectively.

Figure 4.3
Impact of TAC increase on Opt-in decision to IED (MW)



Source: NERA Analysis

4.4.2. Investments by rail industry organisations

There are several potential ways in which an increase in track access charges could affect investment by rail industry organisations. The amount of coal moved by rail seems likely to fall over the next few years, and it is therefore unlikely that significant investment in locomotives, wagons or loading/unloading facilities would be required, irrespective of any change in track access charges. Among other things, this reflects the investments that individual FOCs have carried out in recent years as they have competed for market share, and also the investment made by several major ports so that they can handle large quantities of imported coal.

Biomass, in contrast, is a new market for rail, with only one major flow carried at present. Some investment in specialist wagons will be required in order for FOCs to serve this market in future, either purchasing new wagons or converting existing wagons. While it is certainly possible that such investment could be affected by changes in track access charges, we note that:

- as discussed in Section 3.2.3, the impact of increased track access charges on biomass traffic will depend, in part at least, on whether the Government takes further measures (such as increasing subsidies) to ensure that biomass continues to make its expected contribution to meeting the UK’s renewable energy targets; and
- the impact of changes in track access charges on investment decisions might in any case be relatively small, given the more extensive uncertainty that already exists about the

speed and way in which ESI use of biomass will increase in future, and the extent to which this will create opportunities for significant new rail freight flows.

An indirect but more far-reaching impact on rail industry investment might occur if increases in track access charges lead to changes in the nature of competition between FOCs. In theory, ESI coal traffic should be one of the market segments from which FOCs will aim to recover some of their fixed costs. However, the situation is potentially fragile, as each FOC risks being undercut on particular flows by a competitor willing to accept a lower margin (ie a margin that will make a smaller, but still positive, contribution to recovering the competitor's fixed costs). In the short term, FOCs could also be put under financial pressure if their existing contracts do not allow them to pass on the increase in track access charges to their customers.

In view of the reduction in coal demand that we expect to occur, even if there is no change in track access charges, competition between FOCs for the remaining coal traffic might intensify, perhaps leading to a reduction in margins and, if track access charges do increase, not all of the increase being passed on to generators.

If such developments were to lead a reduction in competition between FOCs, either because a FOC exits the market (either voluntarily or because of financial distress) or through consolidation, this could have far-reaching consequences both for rail freight customers and also for Network Rail, which benefits from competition between the existing FOCs for contracts to run infrastructure maintenance trains.

It is difficult to judge the seriousness of such risks, as the current market structure does not conform to a conventional economic model of competition, and future developments are heavily dependent on the actions and decisions of a relatively small number of key players, including both FOCs (who may have quite different long term strategies) and their customers. This uncertainty already exists, even without a change in track access charges, but could be exacerbated if an increase in track access charges reduces ESI coal demand even further and results in increased pressure on FOC margins.

5. Conclusions

Our main conclusion is that an increase in track access charges of £10 per thousand net tonne kms could reduce ESI demand for coal by around 5 per cent, assuming no change in the proportions of coal that each power station obtains from different sources. For rail freight, the impact on freight moved (net tonne kms) is slightly larger than the impact on freight lifted (net tonnes). While commodity prices movements might lead to a short term increase in ESI demand for coal, even without an increase in track access charges, based on current forecasts we would expect future demand to fall to levels closer to those observed in 2009 and 2010, mainly as a result of the increased CO₂ price floor and the introduction of new, efficient gas generation capacity. And demand might fall even further if the currently expected real increase in gas prices does not materialise.

If the increase in track access charges is larger or smaller than £10 per thousand net tonne kms, then the expected impact on demand rises or falls by a similar amount. We also tested a variant of the £10 increase which is only partly distance-related, which led to a slightly larger reduction in total ESI demand and a slightly smaller impact on the volume of rail freight moved, but the changes were relatively small.

In contrast, ESI demand for nuclear fuel is unlikely to be affected by even quite large changes in track access charges at least in the short-term, assuming no change in investment plans. And the impact on the emerging market for biomass is difficult to predict because it depends on whether (and how) government subsidies are adjusted in order to ensure that renewables targets are still met.

The results reported above are all based on an assumption that the cost increase is passed on in full to each generator. This might not happen if Scottish coal producers decide to absorb some of the increase in the effective cost of the coal they sell to English power stations. This could lead to a lower reduction in overall ESI coal demand, and would also help to limit the impact on the volume of freight moved, especially if long distance Anglo-Scottish flows continue and the expected reduction in demand affects imports instead. However, if the increase in track access charges leads to a reduction in either English power stations' use of Scottish coal or import flows that currently travel a long distance (assuming these have not already been rationalised), this could lead to a larger impact on freight tonne kms. And future rail freight volumes could also be reduced if the long term impact of higher track access charges is to slow down the development of future open cast sites in Scotland.

A further important uncertainty is whether one or more FOC might also absorb some of the cost increase. This might happen if some existing contracts do not allow such cost increases to be passed through, if a FOC makes a deliberate decision to reduce its margins (perhaps to protect particular flows), or perhaps as a result of future competition for contracts (especially if the overall market has also shrunk). In the short term, this might help to insulate generators from the full effect of higher track access charges and therefore moderate any adverse impact on total ESI demand. But the longer term implications will depend on whether such a move leads to any change in the level of competition between FOCs. If competition were reduced because of a market exit decision, consolidation or bankruptcy, this could have wide-ranging implications for both rail freight customers and also infrastructure maintenance costs.

Appendix A. Stakeholder Engagement

In addition to meetings with ORR, NERA presented its work to two meetings of the Variable Track Access Charges (VTAC) Developments Group, and had separate discussions with the following stakeholders:

- Associated British Ports
- Association of Energy Producers
- CoalImp
- CoalPro
- DB Schenker
- Department for Business, Innovations and Skills (BIS)
- Department for Transport
- Department of Energy and Climate Change
- Direct Rail Services
- Drax Power
- Freightliner
- GB Railfreight
- Rail Freight Group
- Scottish Government Energy Directorate
- Transport Scotland

We also received comments from RWE Supply & Trading and Scottish and Southern Energy Supply.

We are grateful to all of the above for their assistance with our study.

Appendix B. Glossary of Acronyms

BETTA	British Electricity Transmission and Trading Arrangements
CCGT	Combined-Cycle Gas Turbine
CP5	Control Period 5 (April 2014 – March 2019)
CPF	Carbon Price Floor
EESyM	European Electricity Simulation Model
ESI	Electricity Supply Industry
ETS	Emission Trading Scheme
EU	European Union
FGD	Flue Gas Desulphurisation
FOC	Freight Operating Company (ie a freight train operator)
GB	Great Britain
IEA	International Energy Agency
IED	(EU) Industrial Emissions Directive
IED	Industrial Emissions Directive
LCPD	Large Combustion Plant Directive
LNG	Liquefied Natural Gas
NAP	National Allocation Plan
NOx	Nitrogen Oxides
ORR	Office of Rail Regulation
OTC	Over the Counter
PR13	Periodic Review 2013
RO	Renewables Obligation
ROCs	Renewables Obligation Certificates
SCR	Selective Catalytic Reduction
SO2	Sulphur Dioxide
WEO	World Energy Outlook

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