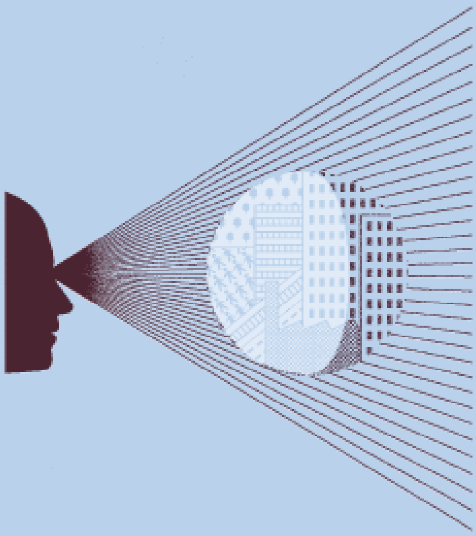
Oxera

Review of the NERA/Imperial impact assessment of introducing a uniform transmission charge

Prepared for ScottishPower and ScottishPower Renewables

November 14th 2011



Executive summary

The objective of Ofgem's Project TransmiT is to provide an independent review of transmission charging and associated connection arrangements. As set out in Ofgem's launch statement in July, a key element of the review is reform of the electricity transmission network use of system (TNUoS) charges under a Significant Code Review (SCR).[1]

In its launch statement, Ofgem reported that the SCR would focus on charging options ranging from 'socialised' charging to an improved 'incremental cost related pricing' (ICRP) approach. Within these two high-level options, there is the possibility of varying the extent to which costs are shared among network users, and the strength of locational price signals, both over time and between different types of generator.[2] The debate over the merits or otherwise of decreasing the strength of locational price signals has been an important consideration since the inception of Project TransmiT in September 2010.[3]

One contribution to this debate was made in a report prepared for RWE npower by NERA and Imperial College (hereafter, the 'NERA/Imperial report'), which presents analysis of the economic impact of introducing a particular model of uniform charging relative to the existing (ie, locational) TNUoS charging methodology.[4] Based on a modelling approach to assess the dynamics of the wholesale power market, transmission network investment and TNUoS charges, the NERA/Imperial report presents an assessment of total power sector and consumer costs.

The starting point for the NERA/Imperial report is its definition of a uniform charge—a single capacity-based charge that is levied on all generators and in which all costs, including local asset charges, are 'socialised' (ie, shared across all network users). (Local asset charges can be significant in the existing charging arrangements, and create a tariff differential of up to £5.6/kW between regions.[5]) This particular form of uniform charge removes all price signals relating to the differences in transmission costs between locations.

The key findings of the NERA/Imperial report are as follows.

– Power sector costs (ie, the costs of conventional and renewable generation, transmission investment, losses and constraints) are estimated to increase in the particular uniform scenario analysed by around £7.5 billion in the period up to 2030.[6] More than half of these costs relate to increased transmission losses driven by significant relocation of conventional generation.

– Consumer costs (ie, wholesale prices, renewables subsidies and network costs recovered from demand charges) are estimated to increase in the uniform scenario by

[1] Ofgem (2011), 'Project TransmiT: electricity transmission charging Significant Code Review launch statement', July 7th.

[2] As discussed in more detail in this report, locational signals can be retained to some degree under certain uniform charging models by applying local asset charges.

[3] Ofgem (2010), 'Project TransmiT: A Call for Evidence', September 22nd.

[4] NERA and Imperial College (2011), 'Project TransmiT: Impact of uniform generation TNUoS', report prepared for RWE npower, March 31st.

[5] Local asset charges to offshore developments can be significantly higher than this.

[6] NERA and Imperial College (2011), 'Project TransmiT: Impact of uniform generation TNUoS', report prepared for RWE npower, March 31st, p. 88.

around £19.8 billion over the same period.[7] Over 70% of the estimated increase in costs is due to the modelled increase in wholesale power prices.

– Renewables output is estimated to remain the same in the uniform scenario and the locational scenario, while support costs increase in the uniform scenario. Deployment is sufficient to meet the UK's 2020 renewables targets under both scenarios, and no further support is given to promote investment beyond 2020.[8]

This report sets out a high-level review of NERA/Imperial's assessment of the impact of introducing a uniform TNUoS charge (ie, a charge that does not vary by location) on power sector costs and consumers within the context of Project TransmiT. The report assesses two key themes in NERA/Imperial's analysis: the impact of NERA/Imperial's modelling assumptions on renewables deployment and thermal plant dynamics, as summarised below.

Renewables deployment

The main conclusions of the NERA/Imperial report in relation to renewables deployment, and the assumptions that lead to these results, are as follows.

Introducing a uniform TNUoS charge—the impact on the UK's performance in meeting its 2020 renewables target

The NERA/Imperial report concludes that the introduction of a uniform charge would not improve the UK's performance in meeting its 2020 renewables target.

The analysis in the NERA/Imperial report assumes technology-specific build rates and resource potential that imply that the UK's renewables target would be met under either locational charges or a uniform charge. The analysis also assumes that, once these targets have been met, no additional renewables generation receives support. Taken together, these assumptions automatically imply that renewables deployment does not increase with the introduction of uniform charging, even though project economics may improve across a number of resource-abundant TNUoS zones as a result.

Introducing a uniform TNUoS charge—the impact on the renewables generation mix

The NERA/Imperial report concludes that a uniform TNUoS charge with socialised local asset charges could lead to an increase in offshore wind deployment and displacement of onshore wind deployment, particularly in South Scotland, and to an associated increase in renewables subsidy costs due to the relatively higher costs of offshore wind. These results are driven by two assumptions—NERA/Imperial assume that:

– both local asset and the wider zonal charges are socialised within the uniform charge, which significantly improves offshore wind economics relative to onshore wind (because offshore wind currently faces relatively high local asset charges);

– projects are developed in strict order of profitability. This implies that, with socialisation of local asset charges, a number of offshore projects are preferred to onshore projects in South Scotland or England and Wales. While this may be a correct starting point in project appraisal in practice, and given the wide variety of renewables technologies and developers vying to participate in the market, it is likely that a number of projects that exceed the relevant developer's hurdle rate would be built in order of deliverability (which is affected by planning, development/construction timescales, risk, and scale of investment), instead of all projects being built in strict order of profitability.

[7] NERA and Imperial College (2011), p. 86.
[8] Ibid., pp. i and 23.

Summary of assessment on renewables deployment

The evaluation in this Oxera report suggests that the results of NERA/Imperial's analysis in relation to renewables deployment are a function of the modelling assumptions used, rather than the general wider effects of introducing a uniform charge.

It is plausible that a lower overall renewable deployment growth rate will be realised than that assumed in NERA/Imperial's analysis. If so, a move away from locational charging by improving project economics in resource-abundant areas, and thereby stimulating additional renewables investment, could increase the likelihood of the UK meeting its 2020 renewables target.

An alternative analysis that considers a uniform charge that retains the locational signal within local asset charges alongside a uniform wider charge might also be expected to stimulate a greater share of onshore deployment relative to offshore wind than that reported in the NERA/Imperial analysis, with correspondingly lower support costs.

Thermal plant dynamics

The key conclusions and assumptions of the NERA/Imperial analysis on thermal plant dynamics, and the assumptions underlying these conclusions, are as follows.

Introducing a uniform TNUoS charge—the impact on the location of new thermal plant

The NERA/Imperial report concludes that a change from the existing charging arrangements to the specific uniform charge it considers would result in the relocation, to Scotland or northern England, of more than 12GW of potential thermal plant that would otherwise have been built in southern zones.[9] This result is driven by the following dynamics.

– New build shifts to Scotland and northern England as a result of lower gas transmission costs in northern regions, where potential power plant sites are close to the gas National Transmission System (NTS) entry terminals.[10] This is despite the fact that the differences in NTS exit charges that drive the NERA/Imperial model to locate virtually all new capacity in Scotland are relatively small,[11] and that NTS exit charges might be expected to change over time in response to new gas infrastructure investment. Indeed, recognising the unlikely nature of this result, the NERA/Imperial analysis itself imposes an exogenous assumption on the geographic distribution of new plant to attenuate this result, although the majority of it is still assumed to be located in Northern England and Scotland.[12]

– NERA/Imperial's analysis of investment decisions does not take account of a number of qualitative siting factors, as acknowledged in their report. For example, NERA/Imperial do not consider the impact of planning constraints, the availability of suitable sites in particular regions, or the availability of cooling water. Such effects are not straightforward to include in a modelling framework, and the NERA/Imperial report notes that 'a wider geographic dispersion of new conventional generators may emerge than

[9] NERA and Imperial College (2011), pp. 41 and 62.

[10] Ibid., p. 61.

[11] Ibid., p. 62.

[12] The geographical spread across these zones has been determined by spreading new investment equally across zones where new entrants are estimated to have fixed O&M costs within £2/kW/year of the lowest fixed O&M. Around 50% of new CCGT and OCGT plant are assumed to be built in Scotland and northern England. See NERA and Imperial College (2011), pp. 62–63.

suggested by our modelling, which may reduce the differences between the scenarios and hence the welfare impacts of a move to uniform TNUoS.'[13]

Introducing a uniform TNUoS charge—the impact on consumer costs

The NERA/Imperial report concludes that consumer costs (including wholesale electricity prices and transmission losses) could increase substantially due to the introduction of a uniform charge.

The prices required to stimulate new investment are higher in the specific NERA/Imperial uniform scenario than under existing locational charges. This is because the NERA/Imperial analysis assumes that new plant locate in regions that have negative charges under the existing locational TNUoS regime, but are no longer incentivised to locate in these regions under a uniform charge. The NERA/Imperial report suggests that this would increase the long-run marginal cost of price-setting, new-entrant CCGTs, thereby significantly increasing wholesale electricity prices, as well as exacerbating transmission losses.

However, in practice, under the existing arrangements, not all new investment is observed in zones with negative charges. For instance, recent investment has taken place in transmission zones with positive charges (eg, West Burton B and Staythorpe C). This is likely to reflect factors in project developers' siting decisions other than TNUoS charges, such as the availability of existing transmission connections.

Any difference in electricity prices due to the introduction of a uniform charge, as defined by NERA/Imperial, may therefore not be as significant as the authors suggest if, under the current locational TNUoS charging regime, marginal new investment is not currently taking place in zones with negative TNUoS charges.

Introducing a uniform TNUoS charge—the impact on plant retirement

The NERA/Imperial report concludes that around 3.6GW of existing capacity in England and Wales would retire more quickly under a uniform charge, as project economics deteriorate for existing plant that face relatively low charges under the current charging arrangements compared with the possible level under a uniform charge.[14]

It is not clear from the NERA/Imperial report how plant retirement decisions have been derived, or how sensitive these results are to changes in the assumptions about underlying commodity price and demand growth. Modelling retirement decisions is not straightforward, since keeping plant capacity open may have an option value if electricity prices are expected to rise, in addition to other diversification and portfolio benefits.

Oxera's analysis of plant retirement decisions using its GB Wholesale Power Model suggests that, under central commodity price assumptions, the introduction of a uniform TNUoS charge may not induce early closure of existing coal or CCGT plant relative to their closure decisions under the existing arrangements. This suggests that further sensitivity testing of the NERA/Imperial analysis may be warranted.

Summary of assessment on thermal plant dynamics

The NERA/Imperial conclusion that a uniform charge could significantly increase consumer costs rests on an exogenous assumption about the location of new thermal plant and its subsequent price impacts. NERA/Imperial assume that long-run wholesale prices would rise to reflect the increase in transmission costs of new plant that might otherwise have been located in zones with negative transmission charges, even though new plant have been

[13] NERA and Imperial College (2011), p. ix.

[14] Ibid., Appendix G.

observed to locate in zones with positive transmission charges even under locational charges, for the siting reasons set out above.

Conclusions

This Oxera review of the NERA/Imperial report on the impact of introducing a uniform charge suggests that the report's conclusions are driven in large part by the particular assumptions used in the NERA/Imperial analysis, rather than being representative of the effects of all potential models of introducing a uniform charge.

The NERA/Imperial report highlights that its analysis is particularly sensitive to certain assumptions, such as relative NTS exit charges, and notes that it omits other siting factors. The analysis in this Oxera review raises further questions about the robustness of some of the other assumptions in the NERA/Imperial analysis, including the impact of alternative renewables build rates; the availability of renewables support after 2020; the impact of the existing structure of locational charges on long-term wholesale electricity prices; and the dynamics behind plant retirement decisions.

It would not appear possible to conclude from the NERA/Imperial analysis that all potential variants of TNUoS charges that reduce the strength of locational signals would increase consumer costs, especially given the possibility of introducing a uniform charge that retains some locational signals through the local asset charge.

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1 Introduction

The objective of Ofgem's Project TransmiT is to provide an independent review of transmission charging and associated connection arrangements. As set out in Ofgem's launch statement in July, a key element of the review is reform of the electricity transmission network use of system (TNUoS) charges under a Significant Code Review (SCR).[15]

In its launch statement, Ofgem reported that the SCR would focus on charging options ranging from 'socialised' charging to an improved 'incremental cost related pricing' (ICRP) approach. Within both of these high-level options, there is the possibility of varying the extent to which costs are shared among network users, and the strength of locational price signals, both over time and between different types of generator.[16] The debate over the merits or otherwise of decreasing the strength of locational price signals has been an important consideration since the inception of Project TransmiT in September 2010.[17]

One contribution to this debate was made in a report prepared for RWE npower by NERA and Imperial College (hereafter, the 'NERA/Imperial report'), which presents analysis of the economic impact of introducing a particular version of a uniform charge relative to the existing (ie, locational) TNUoS charging methodology.[18] NERA/Imperial's analysis is based on a modelling approach to assess the dynamics of the wholesale power market, transmission network investment, and TNUoS charges.

The NERA/Imperial report concludes that the uniform TNUoS charge, as presented in its analysis, would increase generation and transmission costs due to its impact on investment decisions, while having no significant impact on the achievement of the UK's 2020 renewables targets.[19]

The starting point for the NERA/Imperial report is its definition of a uniform charge—a single capacity-based charge that is levied on all generators and in which all costs, including local asset charges, are 'socialised' (ie, shared across all network users). (These local asset charges can be significant in the existing charging arrangements, and create a tariff differential of up to £5.6/kW between regions.)[20] This particular form of uniform charge removes all price signals relating to the differences in transmission costs between locations. The NERA/Imperial report does not examine the sensitivity of its results to changes in these assumptions.

This report sets out a high-level review of NERA/Imperial's assessment of the impact of introducing a uniform TNUoS charge on power sector costs and consumers, and its implications for Project TransmiT. In particular, the analysis focuses on the reasons why the NERA/Imperial report concludes that the introduction of a uniform charge:

– would not improve the effectiveness of efforts to meet the UK's carbon budgets or 2020 renewables target;

[15] Ofgem (2011), 'Project TransmiT: electricity transmission charging. Significant Code Review launch statement', July 7th.

[16] As discussed in more detail in this report, locational signals can be retained to some degree under certain uniform charging models, by applying local asset charges.

[17] Ofgem (2010), 'Project TransmiT: A Call for Evidence', September 22nd.

[18] NERA and Imperial College (2011), 'Project TransmiT: Impact of uniform generation TNUoS', report prepared for RWE npower, March 31st.

[19] Ibid., p. i.

[20] Local asset charges to offshore developments can be significantly higher than this.

– would increase wholesale electricity prices, as well as accelerate the closure of some 3.6GW of generating capacity in England and Wales.

The analysis in this Oxera report examines the assumptions that lead to these results, and provides additional analysis to consider whether the results might change under alternative assumptions and whether they are applicable to alternative uniform transmission charging arrangements.

The report is structured as follows:

– section 2 gives an overview of the modelling approach used in the NERA/Imperial report;

– section 3 presents Oxera's assessment of the conclusions in the NERA/Imperial report in terms of the potential impacts on renewables deployment;

– section 4 presents Oxera's assessment of the conclusions in the NERA/Imperial report in terms of the impact on wholesale electricity prices and conventional plant retirement; and

– section 5 concludes.

2 Overview of NERA/Imperial's approach and impact assessment

The NERA/Imperial report compares the current system of locational transmission charges with a particular model of a uniform charge, and examines the impact on several elements of power sector costs and the overall costs to consumers.

The starting point for the NERA/Imperial report is its definition of a uniform charge—a single capacity-based charge levied on all generators and in which all costs, including local asset charges, are socialised (ie, shared across all network users). This uniform scenario therefore removes all price signals related to the differences in transmission costs between locations.

NERA/Imperial's modelling framework integrates several models covering the dynamics of the wholesale power market, transmission network requirements, and TNUoS charges. This includes a wholesale power model, a renewables investment model, a transmission investment model, and a transmission charging model.

The models are integrated, in that they are 'solved' by completing several iterations that provide the feedback between generation investment decisions, network investment decisions, and the transmission charging model. However, as the NERA/Imperial report identifies, this process does not lead to a single, stable equilibrium, but one in which location decisions 'flip' between regions in alternate iterations.[21]

The high-level findings of the NERA/Imperial report on power sector costs and consumer costs are summarised in Table 2.1.

Table 2.1 NERA/Imperial estimate of the impact on power sector costs of moving to a uniform charge, 2010–30

Power sector costs	NPV (£m, 2010 prices)	Consumer costs	NPV (£m, 2010 prices)
Generation costs	1,557	Wholesale purchases	13,899
Renewables costs	399	Renewables subsidies	262
Losses	4,082	Losses	4,082
Constraints	344	Constraints	344
Transmission investment costs	1,181	Demand TNUoS charges	1,181
Total	**7,564**		**19,768**

Note: All figures are in 2010 prices. Net present values (NPVs) assume a discount rate of 3.5%.
Source: NERA and Imperial College (2011).

The key findings and dynamics within the NERA/Imperial analysis that lead to these results are as follows.

– Power sector costs (ie, the costs of conventional and renewable generation, transmission investment, losses and constraints) are estimated to increase in the uniform scenario modelled, by around £7.5 billion in the period up to 2030. More than half of these costs relate to increased transmission losses, driven by a significant relocation of conventional generation.

[21] NERA and Imperial College (2011), p. ix.

– Consumer costs (ie, wholesale prices, renewables subsidies and network costs recovered from demand charges) are estimated to increase in the uniform scenario modelled, by around £19.8 billion over the same period. More than 70% of the estimated increase in costs is due to the modelled increase in wholesale electricity prices.

  – The prices required to stimulate new investment are higher in the NERA/Imperial uniform scenario than under its locational scenario. This is because new plant is assumed no longer to locate in regions with negative TNUoS charges. The NERA/Imperial report estimates that this could increase the long-run marginal cost of a CCGT at a 60% load factor by around £2.5/MWh.[22]

  – The NERA/Imperial analysis suggests that the uniform charges modelled would accelerate the retirement of conventional plant in southern England, reducing capacity margins compared with the existing arrangements, in turn leading to increased costs from load shedding and from dispatching plant with higher variable costs. The NERA/Imperial report estimates that this could increase costs by as much as £450m per annum in 2015,[23] equivalent to around £1.4/MWh using an annual electricity requirement of 315TWh as per National Grid's Seven Year Statement.[24]

– Renewables output is estimated to remain the same in the uniform scenario modelled and the locational scenario, while support costs are estimated to increase in the uniform scenario. Renewables generation potential is based on the 'high case' scenario in the SKM study produced for the Department for Energy and Climate Change (DECC), which helps achieve the renewables target under both scenarios.[25] The most profitable renewables technologies and sites are assumed to be developed first, which leads to changes in the generation mix between scenarios.

The NERA/Imperial analysis is based on some important model dynamics that are described in the following sections, which also form the main drivers of the report's findings.

– Investment decisions respond to small changes in the relative returns of projects in different locations. This sensitivity to changes in transmission charges is highlighted by the instability between model iterations.

– Investment decisions do not take account of a number of siting factors, as acknowledged in the report:

> we have omitted some factors that affect locational decisions, such as planning constraints on the availability of suitable sites for developing new generators in a particular region, or the availability of cooling water...Therefore a wider geographic dispersion of new conventional generators may emerge than suggested by our modelling, which may reduce the differences between the scenarios and hence the welfare impacts of a move to uniform TNUoS.[26]

– Renewables support costs increase due to a shift towards relatively more expensive renewables technologies, in which increased offshore wind deployment 'occurs primarily because we [NERA/Imperial] assume that the local asset charges faced by offshore wind developers are socialised in the uniform scenario'.[27]

[22] NERA and Imperial College (2011), p. 81.

[23] Ibid., pp. 79–80 and Figure 5.20.

[24] National Grid (2011), 'National Electricity Transmission System (NETS) Seven Year Statement', Table 2.4.

[25] SKM (2008), 'Quantification of Constraints on the Growth of UK Renewable Generating Capacity', June.

[26] NERA and Imperial College (2011), p. ix.

[27] NERA and Imperial College (2011), p. 69.

The remainder of this report examines these assumptions and their effects in more detail.

3 Renewables deployment and its impact on consumers

This section examines the assumptions and modelling approach within the NERA/Imperial report used to assess the impact of adopting a uniform charge on the location and volume of renewables investment.

The NERA/Imperial report concludes that the particular model of uniform charge considered in the report would not improve the likelihood of meeting the UK's 2020 renewables target. This is despite the fact that, according to analysis undertaken by Oxera, a uniform charge would reduce charges in the northern regions of Great Britain, where there is a relative abundance of more readily accessible onshore wind resource.[28]

The NERA/Imperial report also concludes that offshore wind deployment would increase with the introduction of a uniform charge, displacing potential onshore wind projects, and in turn representing a less cost-effective route towards meeting the 2020 renewables target.

This section reviews the extent to which the modelling methodology used in the NERA/Imperial report affects its estimate of the costs and benefits of introducing a uniform charge. Also examined here is whether the conclusions reached in the NERA/Imperial report are representative of other potential variants of uniform transmission charging.

The section is structured as follows:

– section 3.1 summarises NERA/Imperial's modelling results and how they relate to particular modelling assumptions;

– section 3.2 presents analysis to quantify the impact of NERA/Imperial's modelling assumptions on project economics, and to show the sensitivity of NERA/Imperial's findings to these assumptions;

– section 3.3 summarises the main findings.

3.1 NERA/Imperial's modelling assumptions and their implications

The NERA/Imperial analysis makes the following key modelling assumptions about renewables investment.

1. Renewables resource potential is based on the high-case assumption developed by SKM for DECC, and, as a result, the UK's 2020 renewables target is met under the locational charging scenario in the NERA/Imperial analysis. No further support is available to projects beyond those required to meet the targets, and this, in effect, places a cap on the level of deployment.

2. A uniform charge is defined to socialise the cost of local asset charges as well as wider TNUoS charges, the effect of which is to increase the level of the uniform charge by

[28] A report by Oxera in November 2010 examined the potential impact of introducing a uniform charge on onshore wind deployment. The report considered a model with a transmission charging approach that socialised the wider TNUoS charge, but retained the existing local asset charge. It concluded that the introduction of a more uniform charge could increase the deployment of onshore wind, and in turn reduce the need for relatively more expensive offshore wind deployment, in order to meet the UK's 2020 renewables target. See Oxera (2010), 'Principles and priorities for transmission charging reform', prepared for ScottishPower, November, available at www.oxera.com.

around £1/kW relative to a uniform charge that does not socialise local asset charges, thereby significantly altering offshore wind economics.[29]

3. Investment in renewable generation projects occurs in strict order of profitability. While this may be a correct starting point in project appraisal, in practice, and given the wide variety of renewables technologies and developers vying to participate in the market, it is likely that a number of projects that exceed the relevant developer's hurdle rate would be built in order of deliverability instead of projects being built in strict order of profitability.[30] This may be even more likely under the proposals put forward in DECC's Electricity White Paper, which propose that the number and type of projects that receive support under a system of Feed-in Tariffs (FITs) could be centrally determined.[31]

Based on NERA/Imperial's first assumption, the finding that uniform charges do not result in additional renewables output is not surprising. As sufficient renewables capacity to meet the UK's 2020 Renewables target is built under the locational charging scenario, and deployment is restricted so that it cannot exceed those requirements, even if the introduction of a uniform charge were to improve the economics of potential projects in resource-abundant regions, deployment would remain capped at the level required to meet the target; the only impact of introducing a uniform charge would be to alter the mix of renewables deployment in Great Britain.[32]

NERA/Imperial's second and third assumptions lead to the finding that the introduction of a uniform charge that also socialises the local asset charge increases offshore wind deployment, which in turn displaces onshore wind investment. These assumptions also lead to an increase in onshore wind deployment in the north of Scotland, which in turn displaces projects in south Scotland and England and Wales.

The dynamics within the NERA/Imperial analysis that affect the mix of renewable deployment under these assumptions are as follows.

– In the locational charging scenario, onshore wind projects in Scotland are relatively more profitable and developed first, given their relatively high load factors. As sites with high load factors are exhausted, and as increasing north–south power flows raise TNUoS charges in Scotland, sites in England and Wales are developed.[33]

– In the locational charging scenario, only a limited number of Round 3 (R3) and Scottish Territorial Water (STW) offshore sites are developed, given their relatively high costs.

– Under the uniform charging scenario, the ability to avoid high local asset charges incentivises the deployment of wind farms further offshore, as well as onshore wind plant in more remote locations with higher load factors.[34]

– Under the uniform charging scenario, onshore wind capacity in England and Wales is displaced by onshore wind in Scotland, as well as offshore wind, which become relatively more profitable. Within Scotland, the difference in load factors between regions means that onshore wind deployment in north Scotland increases, while that in south Scotland decreases, even though project economics in south Scotland improve, and despite the significant onshore wind resource potential in south Scotland.

[29] Oxera's November 2010 report used a uniform charge (excluding local asset charges) equal to £4.1/kW in 2010, while the NERA/Imperial analysis uses a uniform charge (including local asset charges) of £5.5/kW in 2010.

[30] For example, deliverability could be affected by planning, development and construction timescales, risk and scale of investment.

[31] Department of Energy and Climate Change (2011), 'Planning our electric future: a White Paper for secure, affordable and low-carbon electricity', July.

[32] NERA and Imperial College (2011), p. 21.

[33] Ibid., p. 51.

[34] Ibid., p. 84.

Table 3.1 shows the results of the NERA/Imperial analysis on the impact of uniform charging on wind deployment across zones. It highlights the overall net increase in deployment in North Scotland and Western Highland & Skye, compared with reductions in deployment in South Scotland and South Wales & Gloucester.

Table 3.1 NERA/Imperial assessment of the impact of a uniform charge on the deployment of onshore and offshore wind

Zone		Change due to uniform charge (GW)
1	North Scotland	0.9
3	Western Highland & Skye	0.7
4	Central Highlands	0.1
5	Argyll	0.0
7	South Scotland	–0.2
9	Humber & Lancashire	1.3
10	North East England	–0.1
13	South Yorks & North Wales	–0.1
14	Midlands	–0.1
2	Peterhead	0.1
6	Stirlingshire	0.0
8	Auchencrosh	–0.2
15	South Wales & Gloucester	–3.1
11	Anglesey	–0.2
12	Dinorwig	–0.2
16	Central London	0.0
17	South East	–0.1
18	Oxon & South Coast	0.0
19	Wessex	0.0
20	Peninsula	0.0
Total		
Scotland		1.4
England and Wales		–2.6
Great Britain		–1.2

Note: The NERA/Imperial analysis does not report separate figures for onshore and offshore wind capacity on a regional basis, but does provide an illustration of the changes in onshore and offshore deployment.
Source: NERA and Imperial College (2011), Tables G.4 and G.5.

3.2 Illustrative effects of NERA's modelling assumptions

This sub-section presents analysis to illustrate the scale of the impact of NERA/Imperial's modelling assumptions on representative project economics, and the sensitivity of the conclusions in the NERA/Imperial report to small changes in those assumptions.

The assumptions used to assess the impact of a uniform charge with socialised local asset charges are set out in Table 3.2.[35] Total transmission charges are built up from several components:

– a wider zonal charge and residual charge;
– a local substation charge—the local circuit charge applicable to a representative wind farm in each zone is calculated as an average of the charges to substations within that zone;
– a local circuit charge—there is a wide range in local circuit charges. For the illustrative modelling carried out in this section, the average of the high and low local circuit charges has been used as being representative of the charges applicable to a typical wind farm.

Table 3.2 Transmission charges in 2010/11

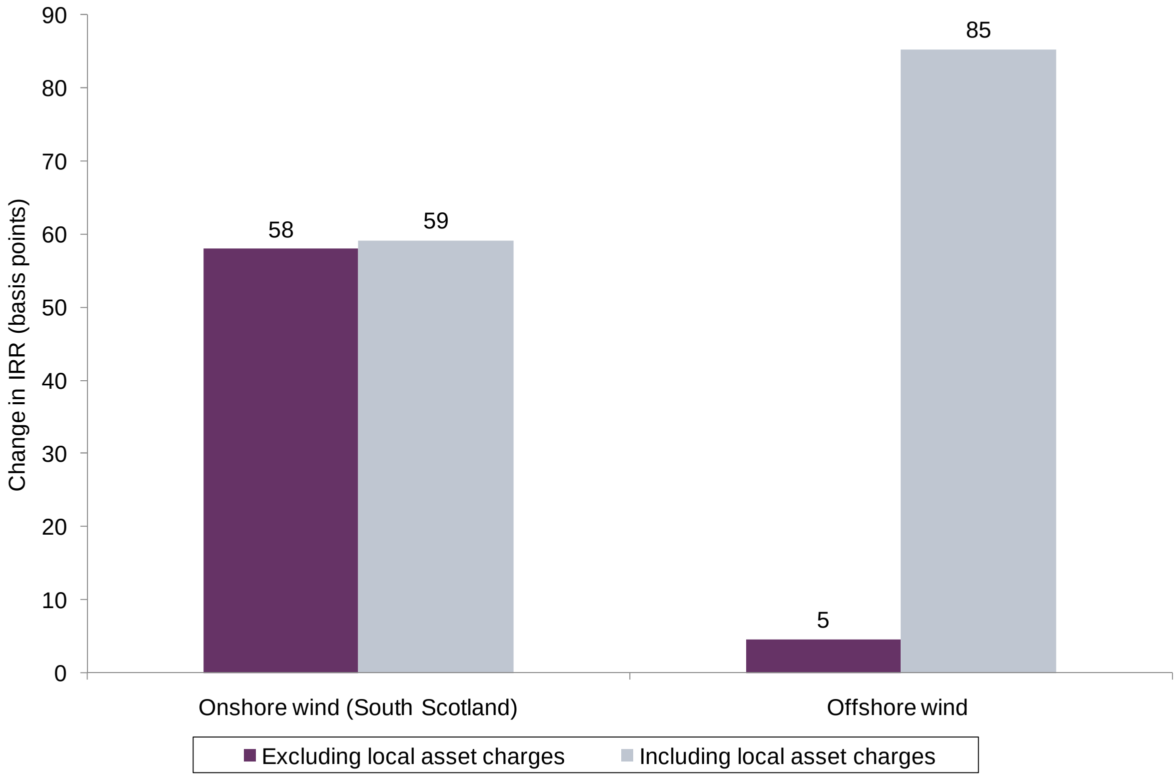
Zone		Wider zonal charge (£/kW)	Local substation charge (£/kW)	Local circuit charge (£/kW)	Total TNUoS (£/kW)
1	North Scotland	20.1	0.2	0 to 4.8	22.7
2	Peterhead	18.7	0.2	0 to 4.8	21.3
3	Western Highland & Skye	22.8	0.2	–0.5 to 4.8	25.1
4	Central Highlands	17.6	0.2	0 to 2.0	18.8
5	Argyll	13.3	0.2	0 to 1.2	14.2
6	Stirlingshire	13.4	0.2	–0.6 to 2.6	14.6
7	South Scotland	12.5	0.2	–0.6 to 2.6	13.7
8	Auchencrosh	10.9	0.2	–0.8 to 0.0	10.8
9	Humber & Lancashire	5.4	0.2	0 to 0.6	5.9
10	North East England	8.8	0.2	0 to 0.4	9.2
11	Anglesey	6.2	0.2	0 to 3.8	8.2
12	Dinorwig	5.5	0.2	0 to 3.8	7.6
13	South Yorks & North Wales	3.6	0.2	0 to 0.2	3.9
14	Midlands	1.6	0.2	0 to 1.3	2.4
15	South Wales & Gloucester	0.4	0.2	0 to 0.1	0.7
16	Central London	–6.4	0.2	0 to 0.3	–6.1
17	South East	0.8	0.2	0 to 0.3	1.1
18	Oxon & South Coast	–1.4	0.2	0 to 0.6	–0.9
19	Wessex	–2.6	0.2	0 to 0.4	–2.3
20	Peninsula	–5.9	0.2	0 to 0.4	–5.5
Uniform charge (excluding local asset charge)[1]					4.12
Uniform charge (including local asset charge)[2]					5.16

Note: [1] The uniform charge (excluding local asset charge) has been calculated by subtracting local asset charges from the total allowed transmission revenue. This figure has then been divided by the transmission entry capacity to obtain the uniform charge. [2] The uniform charge (including local asset charge) has been calculated by dividing the total allowed transmission revenue by the transmission entry capacity.
Source: Oxera analysis.

[35] Although data on the TNUoS assumptions is provided in Appendix F of the NERA/Imperial report, no distinction is made between the local asset charge assumed in each region.

Figure 3.1 illustrates how moving from the existing system of locational charges to the two variants of the uniform charge shown in Table 3.2 above would affect the internal rate of return (IRR) of a representative onshore wind project in South Scotland and a representative offshore project.

Figure 3.1 Effects on IRRs of adopting alternative variants of a uniform charge compared with a locational charging approach



Note: The onshore wind costs underlying this analysis are those of an Nth-of-a-kind (NOAK) plant with medium costs, with the offshore costs being those of an NOAK plant with medium costs. The offshore wind analysis assumes that a uniform charge applied to a representative offshore wind plant comprises the wider zonal charge of zone 9 (£5.4/kW), with local substation charges (–£0.36/kW) and circuit charges (£24.1/kW). Offshore local asset charges are site specific, with limited information publicly available. The local asset charges used in this analysis are based on those for Robin Rigg East and Robin Rigg West. Local asset charges for subsequent offshore projects—particularly Round 3 projects—are likely to be higher than those for Robin Rigg and could be significantly higher in some circumstances.
Source: Mott MacDonald (2010), National Grid, 'The Statement of Use of System Charges. Effective from 1 April 2011'; and Oxera analysis.

Figure 3.1 shows that, following the introduction of a uniform charge, project returns could increase for both potential projects. However, due to the local asset charge saving from the introduction of this particular variant of a uniform charge, the relative impact of socialised local asset charges could be significantly greater on offshore project economics. This effect is highlighted in the NERA/Imperial report as a key driver of the change in offshore wind development under the uniform charge.[36]

Table 3.3 (and Figures 3.2 and 3.3) below illustrates the changes in the economics of onshore wind generation across TNUoS zones with the introduction of a uniform charge using the NERA/Imperial approach to calculate the uniform charge (ie, assuming that local asset charges are socialised). The table also shows the share of wind resource, and relative ranking of the returns of the representative project in each region.

[36] NERA and Imperial College (2011), p. 84.

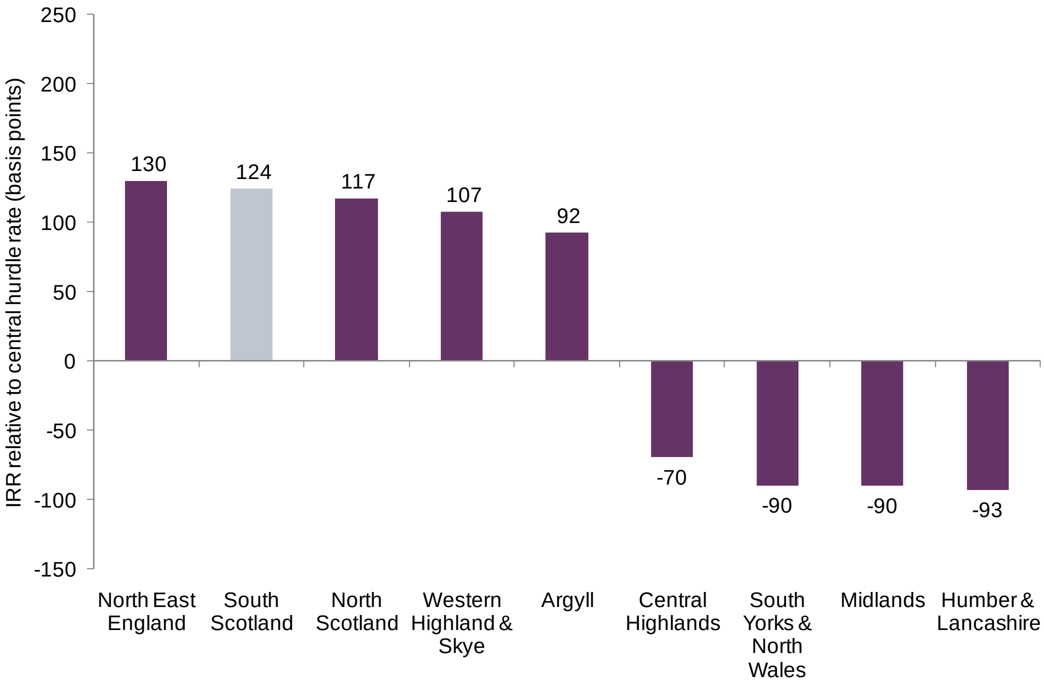
Table 3.3 Change in onshore IRR ranking due to the introduction of a uniform charge (with socialised local charges)

Zone	Share of resource potential (%)	Rank of IRR relative to central hurdle rate—locational charges[1]	Rank of IRR relative to central hurdle rate—uniform charge	Change in IRR (basis points)
North East England	5	1	4	26
South Scotland	37	2	3	59
North Scotland	14	3	2	110
Western Highland & Skye	8	4	1	124
Argyll	5	5	5	57
Central Highlands	7	6	6	89
South Yorks & North Wales	16	7	8	–8
Midlands	6	8	9	–18
Humber & Lancashire	5	9	7	5

Note: The share of the resource potential is based on the SKM (2008) high scenario and analysis of British Wind Energy Association (now RenewableUK) data. [1] The central hurdle rate is based on Oxera (2011), 'Discount rates for low carbon and renewable generation technologies', April, prepared for the Committee on Climate Change.
Source: Oxera analysis.

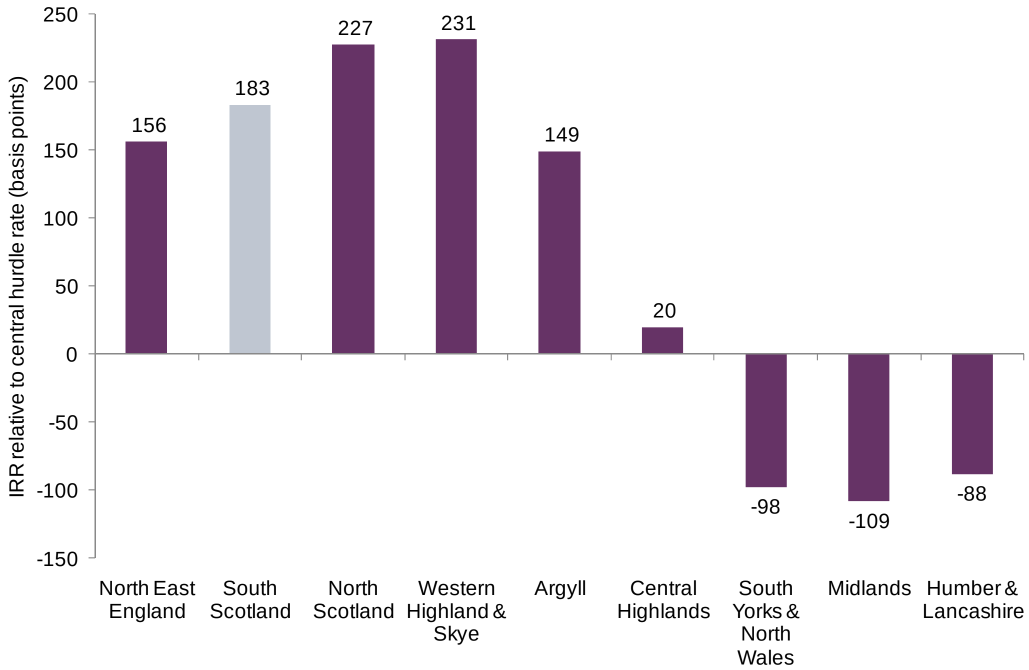
Table 3.3 and Figures 3.2 and 3.3 highlight that onshore wind economics in South Scotland and North East England could improve following the introduction of a uniform charge (with socialised local asset charges). However, the relative rank of the level of returns of onshore projects in South Scotland could fall, as the representative projects in Western Highland & Skye and North Scotland become relatively more attractive.

Figure 3.2 IRR of a representative project compared with central hurdle rates with locational charges



Note: This figure shows the difference between the point estimates of the IRR of a representative project above Oxera's central estimate of a potential developer's hurdle rate. A range of potential projects is likely to exist in each region with varying returns around this central estimate.
Source: Oxera analysis.

Figure 3.3 IRR of a representative project compared with central hurdle rates with a uniform charge (including socialised local asset charges)



Note: This figure shows the difference between the point estimates of the IRR of a representative project above Oxera's central estimate of a potential developer's hurdle rate. A range of potential projects is likely to exist in each region with varying returns around this central estimate.
Source: Oxera analysis.

The above analysis highlights that, while a uniform charge (with socialised local asset charges) may improve project economics across a number of resource-abundant transmission charging zones, the level of deployment and resulting mix of onshore and offshore generation depend on the assumptions made about the order and priority in which projects are developed. In contrast to the conclusions of the NERA/Imperial report, it is likely that, under a uniform charge with socialised local asset charges, developers would proceed with onshore projects in South Scotland in addition to, or possibly as a priority over, potential offshore developments. This possibility is driven by differences in factors such as planning and construction lead times, site accessibility and technology risk.

The analysis also highlights that, given the relatively similar levels of returns of representative projects across a number of northern charging zones, NERA/Imperial's modelling assumption—in which deployment switches regions in response to small variations in returns—could lead to the counterintuitive result that significant onshore resource in regions such as South Scotland is not developed, even though returns increase, and are above project sponsors' hurdle rates. In practice, a number of factors other than hurdle rates determine deployment decisions. These include planning processes, site accessibility and project development times.

3.3 Summary

The NERA/Imperial analysis concludes that there would be no additional deployment under a uniform charge with socialised local asset charges than under the existing locational charging arrangements. This result is driven by the modelling assumptions adopted on technology build-rate constraints and resource potential, which are such that the renewables target is met under both scenarios, and deployment is capped at the level required to meet the UK's 2020 renewables target.

The NERA/Imperial analysis also finds that introducing a uniform charge would increase offshore wind deployment, and displace potential onshore wind projects, including in South Scotland, leading to an increase in net support costs. These results are driven by the assumption that local asset charges are socialised, which significantly improves offshore wind economics relative to onshore, and the assumption that projects are developed in strict order of profitability, so that offshore projects are preferred to those in South Scotland or England and Wales, notwithstanding relatively small differences in returns, technology risks, project lead times and project sponsors' attitude to risk.[37]

Given the range of variants of possible uniform transmission charging arrangements, such as introducing uniform transmission charging that retains some locational signals through the local asset charge, it would appear inappropriate to conclude from the NERA/Imperial analysis that all systems of transmission charging that reduce the strength of locational signals would significantly increase consumer costs.

Under alternative uniform transmission charging models that improve the economics of a number of marginal onshore wind projects, Oxera analysis concludes that such arrangements could lead to a more efficient mix of renewables deployment, by facilitating the optimum realisation of relatively inexpensive onshore wind resources.[38]

[37] A number of other factors can also affect decisions between projects. These include planning considerations, delivery time, and construction risk. As such, less profitable onshore projects may still be targeted in preference to some offshore projects.
[38] Oxera (2010), 'Principles and priorities for transmission charging reform', November.

4 Thermal plant dynamics

This section examines the assumptions and modelling approach within the NERA/Imperial report used to assess the impact of adopting a uniform charge on the location of thermal generating plant.

The NERA/Imperial report concludes that adopting a uniform charge (with socialised local asset charges) would have the following effects.

– More than 12GW of new CCGT and OCGT plant is estimated to locate in Scotland and the north of England in the next two decades. (According to the NERA/Imperial analysis, no CCGT or OCGT plant would be located in these areas under locational charges.)[39]

– Around 3.6GW of existing capacity is estimated to retire more quickly. This is because project economics worsen for existing plant that face relatively low charges under the current charging arrangements compared with the possible level under a uniform charge (with socialised local asset charges).[40]

The sub-sections below describe the assumptions within the NERA/Imperial analysis that lead to these results, and consider the robustness of those assumptions. Also considered is whether the results are representative of the effects that might be associated with a wider set of uniform charging options other than the specific form of uniform model examined in the NERA/Imperial report.

4.1 Thermal investment decisions

The NERA/Imperial report considers a uniform charging scenario in which thermal plant are subject to the same level and structure of transmission charges as other forms of generation. That is, no locational signal is provided to thermal plant, nor is any restriction placed on their development behind transmission constraints, or where significant new transmission investment would be required.

The main conclusions of NERA/Imperial's analysis on thermal investment decisions are as follows.

– A relatively limited location of new thermal plant is assumed under both of the scenarios in the NERA/Imperial analysis. This is primarily assumed to be in zones with negative transmission charges (ie, southern zones) under the locational charging scenario; and in zones 1 to 10 (ie, Scotland and Northern England) under the uniform charge scenario. In particular, the NERA/Imperial analysis finds that a change from the existing charging arrangements to a system of uniform charging would induce more than 25GW of potential thermal plant that would otherwise be built in southern zones to relocate to Scotland, although this is subsequently adjusted in the analysis to 12GW, to reflect a 'more realistic' scenario.[41]

– A significant driver of the overall findings of the NERA/Imperial report—such as the impact on new-entrant costs, network costs and losses—stems from the location decisions of investments in thermal plant that are assumed in the analysis. The NERA/Imperial report concludes that significant investment in Scotland would lead to an

[39] NERA and Imperial College (2011), pp. 41 and 62.

[40] Ibid., Appendix G.

[41] Ibid., pp. 41 and 62.

increase in wholesale electricity prices. This arises because the NERA/Imperial analysis suggests that prices are set by new plant locating in regions with negative TNUoS charges under the existing locational charging regime, but by plant in Scottish and northern zones under a uniform charge.

The remainder of this sub-section considers the plausibility of the site modelling analysis adopted in the NERA/Imperial report.

Siting decisions—impact of gas NTS charges

The NERA/Imperial report states that, under its uniform charging scenario, the main driver of new CCGT and OCGT plant location decisions is the difference in gas transmission costs. Under this scenario, the NERA/Imperial analysis maintains that these charges remain lower in northern regions, where potential power plant sites are close to the gas NTS entry terminals.[42]

The effect of this modelling approach is that the NERA/Imperial report concludes that a change from the existing charging arrangements to a uniform charge would induce more than 25GW of potential thermal plant, which would otherwise be built in southern zones, to relocate to Scotland; however, the cost differences that create this result are small. As the NERA/Imperial report states:

> the differences in NTS exit charges that drive the model to locate virtually all new capacity in Scotland are relatively small.[43]

Recognising that this result is not 'realistic',[44] the NERA/Imperial analysis imposes an exogenous assumption on the geographic distribution of new plant, with more than 12GW located in zones 1 to 10, in order to moderate this effect.[45]The NERA/Imperial report does not discuss the possibility that NTS exit charges may change over time—for example, owing to investment in new gas infrastructure—and the extent to which gas flows may change over time. This would appear to warrant consideration if it could act to alter the relative NTS charges in Great Britain, and hence the siting assumptions in NERA/Imperial's analysis.

Siting decisions—other siting drivers

It is possible that significant capital and financing cost savings may be available to thermal plant developers by opting to redevelop existing sites rather than relocate. However, the NERA/Imperial analysis does not attempt to model this important factor.

The NERA/Imperial report acknowledges that other siting factors are not considered:

> we have omitted some factors that affect locational decisions, such as planning constraints on the availability of suitable sites for developing new generators in a particular region, or the availability of cooling water.[46]

Such effects are not straightforward to include in a modelling framework, and the NERA/Imperial report concludes that 'a wider geographic dispersion of new conventional generators may emerge than suggested by our modelling, which may reduce the differences between the scenarios and hence the welfare impacts of a move to uniform TNUoS.'[47]

[42] NERA and Imperial College (2011), p. 61.

[43] Ibid., p. 62.

[44] Ibid., p. 62.

[45] The geographical spread across these zones has been determined by spreading new investment equally across zones where new entrants are estimated to have fixed O&M costs within £2/kW/year of the lowest fixed O&M. Around 50% of new CCGT plant and OCGT plant are assumed to be built in Scotland and northern England. See NERA and Imperial College (2011), pp. 62–63.

[46] Ibid., p. ix.

[47] Ibid., p. ix.

Siting decisions—evidence from current investments

In light of the range of factors influencing plant siting decisions, as identified above, a greater number of geographically diverse new sites are likely to be developed, even under a locational transmission charging scenario, than is assumed by the NERA/Imperial analysis.

Market developments seem to confirm this. For example, the West Burton B and Staythorpe C plant are being developed in zone 13, which has a locational TNUoS charge of around £3.6/kW.[48]

Impact of siting decisions on NERA/Imperial conclusions

The above considerations suggest that significant factors that affect location decisions are acknowledged, but excluded from the NERA/Imperial analysis. It follows that wholesale electricity prices under a locational scenario that reflect new-entry costs should therefore include higher transmission costs than those in the NERA/Imperial analysis.

Consequently, the conclusion in the NERA/Imperial report—that the introduction of a uniform charge would increase the transmission charges faced by the marginal new entrant, and subsequently increase long-run prices—would not appear to be fully tested. Further analysis would appear warranted to examine the impact of the observed location of new plant on prices under the existing arrangements.

4.2 Plant closure decisions

The NERA/Imperial report concludes that the system of uniform charging that it has modelled would accelerate the retirement of existing thermal plant, and in turn raise the costs associated with load shedding and the need to dispatch plant with relatively high variable costs.

The NERA/Imperial report does not set out how plant retirement decisions have been determined or the sensitivity of its results to changes in its underlying commodity price and demand growth assumptions. This sub-section provides insight from Oxera's GB power market model, which suggests that the retirement of existing thermal generation in southern charging zones may not be as certain as the NERA/Imperial report suggests.

Modelling plant retirement decisions is not straightforward—the ability to defer the closure of a power plant provides an option value, the value of which increases with uncertainty in the outlook for the level of future prices and demand. Existing capacity held by large integrated companies can also have diversification and portfolio benefits.

However, to better understand retirement dynamics, illustrative analysis is set out below on the potential impact of a uniform charge on the viability of existing plant in the south of England. To the extent that the analysis does not include option values and other strategic benefits, the results can be thought to reflect relatively extreme retirement impacts.

Plant contributions

Contribution is defined as a plant's revenues minus its variable costs. When the level of contribution is below the plant's fixed costs, it is economic to cease production either temporarily (ie, to mothball) or to close altogether. It is therefore important to consider whether periods in which the level of contribution is less than a plant's fixed costs are likely to persist. This is because the prospect of higher revenues in the future may make it economic for the plant to remain open.

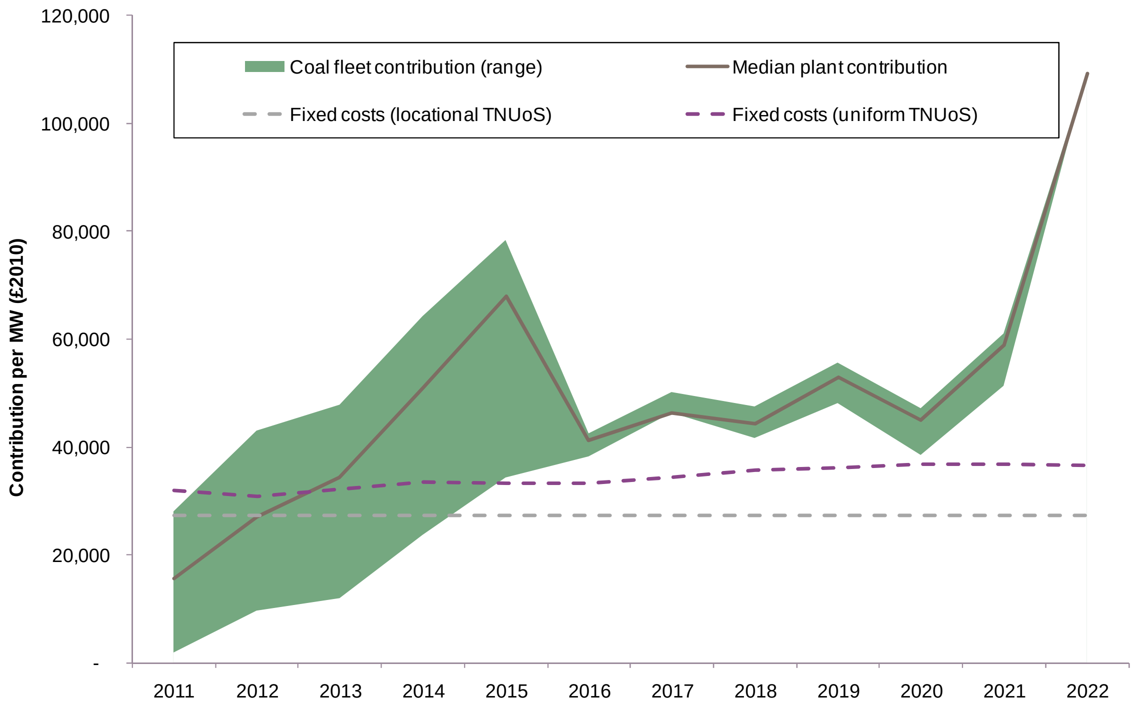
Figure 4.1 shows the range of the annual contribution of the existing coal fleet within the southern charging zones 14 to 20. The figure uses Oxera's base-case commodity and demand assumptions and locational transmission charges, alongside indicative fixed costs

[48] National Grid Seven Year Statement, Table F-1.

under the existing charging arrangements and the uniform charge assumed by NERA/Imperial.

The top and bottom of the shaded region in the figure represents the contribution of coal plant with the highest and lowest revenues respectively. Plant with contribution above its fixed costs under the existing charging arrangements, but below the fixed costs under the uniform scenario with socialised local charges, may be more likely to close early as a result of a change in transmission charges.

Figure 4.1 Contribution to fixed and capital costs of coal plant in zones 14 to 20



Note: Oxera's base case includes the three coal plant that have opted out of the Large Combustion Plant Directive (LCPD) and are due to close by 2015, with a further four coal plant retiring before 2023, and two plant remaining open beyond this date. Fixed costs are assumed equal to £27/kW (in 2010 prices) in the locational scenario, based on SKM (2008). Fixed costs are up to £10/kW higher in the uniform scenario based on results in the NERA/Imperial report.
Source: Oxera analysis.

The figure highlights that:

– the range of annual contributions across the coal fleet is widest before 2015, due to differences in plant efficiency and the operating restrictions faced by plant that have opted out under the LCPD. However, the range is much narrower from 2016, as older, less efficient, plant has retired by that point in time;
– the uniform charge assumed in the NERA/Imperial report increases the fixed costs of a plant in the south of England by around £10/kW;
– the contribution of the existing coal fleet that remains open from 2016 in the locational scenario is sufficient to cover the fixed costs under the uniform scenario.

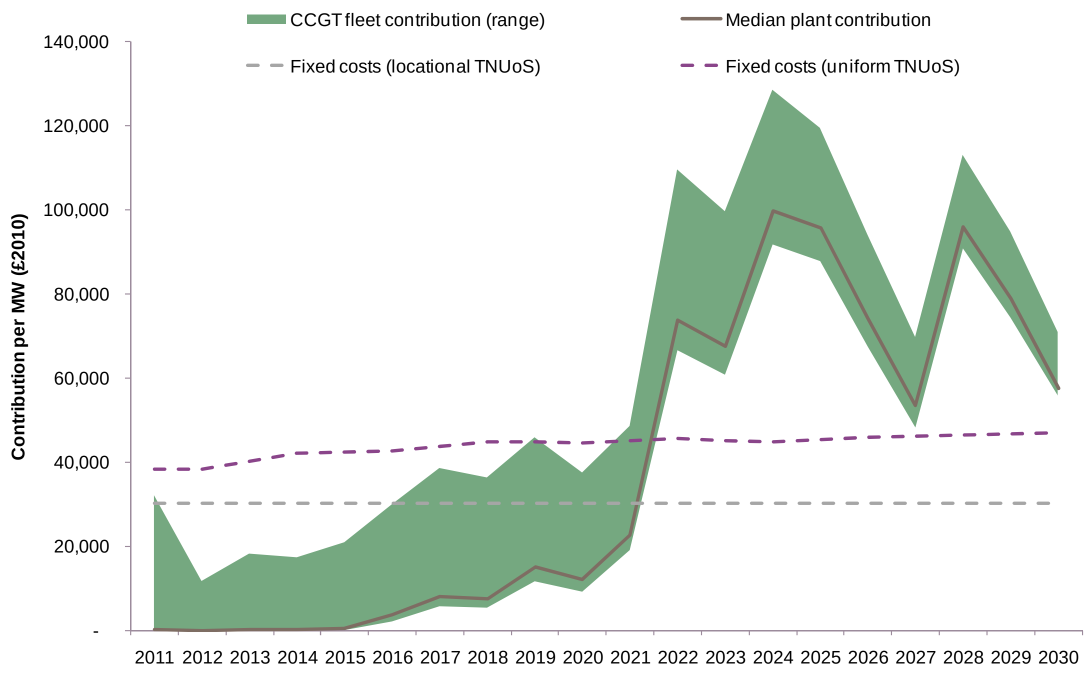
The figure suggests, contrary to the NERA/Imperial analysis, that a uniform charge with socialised local charges may not necessarily induce early closure of existing coal plant in the central and southern GB transmission zones, relative to their closure decisions under the existing arrangements.

A number of underlying model assumptions can affect plant contributions and hence retirement decisions. These include the assumptions about electricity demand growth, which can affect plant utilisation, and about new (more efficient) entry, which, in turn, can displace the output from existing generators.

The NERA/Imperial analysis assumes significant new investment in CCGT plant (1.2GW in 2014, 6.2GW in 2016, and a further 2.1GW in 2017), which may lead to particularly low contributions for the existing coal fleet. Thus, the viability of existing coal plant within NERA/Imperial's analysis may be more sensitive to changes in transmission charges if utilisation levels are significantly depressed as a result of this assumed investment in new CCGTs.

Figure 4.2 shows a similar analysis for the existing CCGT fleet.

Figure 4.2 Average contribution from CCGT plant in BMRS zones 14 to 20



Source: Oxera analysis.

Figure 4.2 shows that:

– the average contribution of CCGT plant in central and southern GB transmission zones is expected to be lower than the assumed fixed cost in the next decade. However, it is expected to rise sharply in the early 2020s in line with higher projected electricity prices;
– as such, there may be a significant incentive to mothball certain CCGT plant in central and southern GB transmission zones in the next decade;
– there remains significant upside in terms of returns in the 2020s, even under a uniform charging scenario. Moreover, as the proportion of wind output grows over the next decade, CCGT plant might be expected to benefit from further upside, as a provider of flexible capacity with the potential to capture higher realised prices during periods of low wind.

The above analysis suggests that there may be significant year-on-year volatility in existing plant returns for the given scenario of underlying commodity prices and electricity demand. Moreover, under Oxera's base case, the extent to which the closure decisions of existing southern plant are marginal, and hence the extent to which retirement decisions are particularly sensitive to changes in transmission charges, is low.

This suggests that the findings in the NERA/Imperial analysis—that a uniform charge with socialised local charges would induce different retirement profiles within these zones—may depend on the specific commodity price and demand growth assumptions used, although further details would be required to test this.

4.3 Summary

The analysis in this section highlights the following.

- Thermal plant investment decisions within the NERA/Imperial analysis are particularly sensitive to small variations in costs, and differences in gas NTS exit charges cause the model to locate virtually all new capacity in Scotland. To attenuate this extreme result, the NERA/Imperial analysis imposes an exogenous assumption on the geographic distribution of new plant, although the majority of it is still assumed to be located in Northern England and Scotland. Further testing of the robustness of this assumption may be warranted if relative NTS charges across Great Britain are likely to change over time with investment in new gas infrastructure.

- The NERA/Imperial report concludes that significant investment in Scotland and northern England would lead to an increase in wholesale electricity prices. This arises because the NERA/Imperial analysis suggests that the long-run marginal costs of price-setting new plant are located in negative TNUoS charges under the existing locational charging regime, but in Scottish and northern zones under a uniform charging regime with socialised local charges.

- However, important siting factors are excluded from the NERA/Imperial analysis that appear to affect location decisions in practice. For example, under the existing arrangements, new investment is taking place in transmission charging zones with non-negative charges (such as the West Burton B and Staythorpe C developments, which are located in zone 13).

- Consequently, the conclusion in the NERA/Imperial report that the introduction of a uniform charge would increase the transmission charge faced by the marginal new entrant, and subsequently increase long-run prices, would not appear to be fully tested. The transmission charges faced by new entrants under the existing locational charges would appear to be higher than those implied in the NERA/Imperial analysis. Further analysis would therefore appear to be warranted to examine the impact of the observed location of new plant on prices under the existing arrangements.

- NERA/Imperial's conclusion, that the introduction of a uniform charge could cause around 3.6 GW of existing capacity in England and Wales to retire more quickly, is not transparent for the following reasons.

  - The NERA/Imperial report does not explain how its plant retirement decisions have been derived; nor does it set out the relevant drivers that could delay plant retirement.

  - Oxera's analysis of plant retirement decisions using its GB Wholesale Power Model indicates that the introduction of a uniform charge would not necessarily induce early closure of existing coal or CCGT plant relative to their closure decisions under the existing arrangements.

  - This suggests that further sensitivity analysis may be required in order to understand whether the introduction of a uniform charge would have a material impact on the retirement decisions of existing thermal plant, and its potential effects on capacity margins and consequent price impacts.

5 Conclusions

This report has provided a review of NERA/Imperial's assessment of the impact of introducing a particular model of uniform transmission charging within the context of Project TransmiT.

The NERA/Imperial report concludes that the uniform charge, as presented in its analysis, would increase generation and transmission costs owing to its impact on investment decisions, while having no significant impact on the achievement of the UK's 2020 renewables targets.[49]

The assessment in this review by Oxera suggests that the findings of the NERA/Imperial analysis are driven, in particular, by the modelling assumptions used, and cannot therefore be generalised to draw conclusions about the impact of alternative options of uniform transmission charging that reduce the strength of locational signals relative to the current arrangements.

Renewables deployment

The NERA/Imperial analysis concludes that there would be no additional deployment under a uniform charge compared with the existing locational charging arrangements. This result is driven by the modelling assumptions adopted on technology build-rate constraints and resource potential, which are such that the 2020 renewables target is met under both scenarios, and deployment is capped at the level required to meet the renewables target.

The NERA/Imperial analysis also finds that the form of uniform transmission charging that it examines would increase offshore wind deployment, and displace more cost-effective potential onshore wind projects, particularly in South Scotland, leading to higher net support costs. These results are also driven by the assumption that local asset charges are socialised, which significantly improves offshore wind economics relative to onshore, and that projects are developed in strict order of profitability, so that offshore projects are prioritised ahead of onshore projects in South Scotland or England and Wales, notwithstanding project sponsors' attitude to risk.

Oxera analysis suggests that uniform charging is likely to improve the economics of a number of marginal onshore wind projects in resource-abundant charging zones, and hence it is plausible that this option could lead to a more efficient mix of renewables deployment, by facilitating the optimum realisation of relatively inexpensive onshore wind resources instead of offshore ones.

Thermal plant dynamics

The considerations in Oxera's analysis also highlight that the conclusions of the NERA/Imperial report on the impact of adopting a uniform charge with socialised local charges on thermal plant investment decisions and retirement is particularly sensitive to the modelling assumptions used.

In terms of investment in new plant, the NERA/Imperial report explains that thermal plant investment decisions within its analysis are particularly sensitive to small variations in costs, and that differences in gas NTS exit charges drive the model to locate virtually all new capacity in Scotland. To adjust for this extreme result, the NERA/Imperial analysis imposes

[49] NERA and Imperial College (2011), p. i.

an exogenous assumption on the geographic distribution of new plant, the majority of which is located in Scotland and Northern England.

The NERA/Imperial report concludes that significant investment in Scotland and northern England would lead to an increase in wholesale electricity prices. This arises because NERA/Imperial assume that prices reflect the long-run marginal costs of new plant locating in regions with negative TNUoS charges under the existing locational charging regime, but by plant in Scottish and northern zones under a uniform charge.

Important siting factors are excluded from the NERA/Imperial analysis that appear to affect location decisions in practice. For example, under the existing arrangements, new investment is taking place in transmission charging zones with non-negative charges (such as the West Burton B and Staythorpe C developments, which are located in zone 13). It follows that prices that reflect new-entry costs under the existing arrangements are likely to include a different set of transmission costs to those in the NERA/Imperial analysis. Consequently, the conclusion that the transmission charge faced by the marginal new entrant is likely to increase with the introduction of uniform charging, and ultimately feed into wholesale prices, would not appear to be fully tested.

Modelling plant retirement decisions is not straightforward—the ability to defer the closure of a power plant provides an option value, the value of which increases with uncertainty in the outlook for the level of future prices and demand. Existing capacity held by large integrated companies can also have diversification and portfolio benefits.

The NERA/Imperial analysis anticipates significant new investment in CCGT plant. Thus, the viability of existing plant within NERA/Imperial's analysis may be more sensitive to changes in fixed costs if utilisation levels are significantly depressed as a result of this investment. This suggests that the findings in the NERA/Imperial analysis—that the introduction of a uniform charge with socialised local charges would induce different retirement profiles within southern zones—may depend on the specific commodity price and demand growth assumptions used, although further details would be required to test this.

Summary

This review of the NERA/Imperial report suggests that the conclusions of the NERA/Imperial analysis are driven in large part by the particular assumptions used, rather than being representative of the effects of all potential models of uniform transmission charging.

The NERA/Imperial report highlights that its analysis is particularly sensitive to certain assumptions, such as relative NTS exit charges, and notes that it omits other siting factors, but does not analyse the impacts of either of these factors. The analysis in this review by Oxera raises further questions about the robustness of a number of other assumptions in the NERA/Imperial analysis, including the impact of adopting central rather than high renewables build rates; the availability of renewables support after 2020; the impact of the existing structure of locational charges on long-term wholesale electricity prices; and the dynamics behind plant retirement decisions.

It would not appear possible to draw firm conclusions from the findings of the NERA/Imperial report regarding the impact of introducing uniform charges on consumer costs or renewables deployment.

Oxera analysis suggests that uniform charging is likely to improve the economics of a number of marginal onshore wind projects in resource-abundant charging zones, and hence it is plausible that this option could lead to a more efficient mix of renewables deployment, by facilitating the optimum realisation of relatively inexpensive onshore wind resources instead of offshore ones.

Determining the impact of the introduction of a uniform charge on wholesale electricity prices is not straightforward. However, the NERA/Imperial analysis does not appear to capture the locational incentives of the existing arrangements and their implications for wholesale prices. It would therefore not appear possible to conclude from the NERA/Imperial report that a uniform charge would increase the costs of a price-setting new entrant relative to the existing arrangements, or what effect it may have on longer-term prices.

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