A review of "Project TransmiT: Impact of Uniform Generation TNUoS prepared for RWE npower"

A report by Redpoint Energy for Scottish and Southern Energy Plc

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Contents

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1 Executive Summary

Ofgem launched Project TransmiT, which is its review of transmission charging and associated connection arrangements, with a call for evidence on 22 September 2010. The objectives of Project TransmiT are to ensure that transmission charging "facilitates timely transition to a low carbon energy sector which continues to provide safe, secure, high quality network services at value for money to existing and future consumers".

Ofgem's call for evidence has attracted a wide range of responses and views and a range of possible transmission pricing models have been proposed. A number of participants have estimated, or are currently trying to assess, the impact of the alternative policy options being considered and examine the impact of different transmission charging options (eg "postalisation", locational TNUoS) as well as different energy market arrangements (eg Locational Marginal Pricing – "LMP") on the electricity system. In this context, NERA Economic Consulting and Imperial College London were commissioned by RWE npower ("RWE") to compare the current system of locational TNUoS charging for power generators (the "Localised Scenario") with a system of uniform generator charges (the "Uniform Scenario").

The NERA/Imperial report concludes that the introduction of a completely flat Uniform TNUoS would significantly change the locational pattern of generation plant, that it would lead to new gas-fired generation locating in Northern Britain, mainly Scotland, on the basis that access to gas is cheapest there and that wind development would move further offshore. As a result, infrastructure costs, losses, congestion and wholesale prices would increase. Their overall conclusions are that this would lead to an increase in system costs of between £7.9bn and £9.8bn over the period to 2030 and an increase in consumer costs of £20bn NPV.

Our overall assessment is that the assumptions used lead to exaggerated potential benefits of localised versus socialised transmission charging models and the report as a whole does not adequately represent the range of likely outcomes or key sensitivities. In summary:

- The Uniform Scenario chosen, with postage stamp charges and no separate local asset charges (for clarity this is not the model proposed by Scottish and Southern Energy Plc), is at the extreme end of the level of socialisation. Hence, the results cannot be assumed to be representative for most variants of the Uniform Scenario.
- The analysis does not set the additional costs of uniform charging models against the potential wider environmental and economic benefits of more rapid electricity system decarbonisation. We believe that the fact the two models considered produce the same levels of renewables deployment is a function of the assumptions used and the modelling methodology, and this potential benefit of uniform models has therefore not been sufficiently considered.
- The results are very sensitive to the assumptions used, and with only one case modelled it is not easy to get a sense of how representative the results are of a 'central' case or their reasonableness. In particular, factors other than transmission charging that affect siting decisions, such as planning constraints, cooling water access and availability of staff and engineering resources have not been considered.
- Based on our assessment, we challenge the credibility of some of the assumptions made and believe that overall they have produced a result, an increase in consumer costs of £20bn NPV, which is at the very high end of possible increase in costs under the Uniform Scenario analysed and to which a very high degree of caution should be applied for the following reasons:
  - A significant proportion (around £5.2bn) of the additional £7.6bn of power sector costs reported for the Uniform Scenario is associated with the large quantities of new CCGT/OCGT built in Scotland by the model as well as the large quantities of CCGTs/OCGTs built in Zone 17 in the Localised Scenario. We believe that this is an unlikely outcome and not representative of a central

case. Of particular concern is that the plant build decisions appear to be driven by relatively small differences in locational signals whilst other important siting drivers appear to be ignored. This initial premise appears to flow through into increases in wholesale price, congestion, losses and transmission infrastructure costs.

- The extent to which consumer costs increase more than power sector costs (£19.8bn compared to £7.6bn) seems extremely high and unsustainable. Approximately 70% of this increase appears to be attributed to higher wholesale electricity prices. A very large part of the wholesale cost conclusion is directly dependent on the location assumption and the assumption that these additional costs pass straight through. Given this, a very high degree of caution should be applied given the sensitivity of wholesale electricity prices to assumptions and this should have been recognised much more explicitly in the report.
- We estimate that renewables support costs could be £4bn-£5bn lower under the Uniform Scenario, given lower costs for renewable generators, which would also significantly reduce the impact on consumers.

Therefore, we believe that on the basis of the scenarios chosen and the assumptions used, it is not possible to conclude that retaining the current transmission charging regime is the best option given the ambitious objectives to decarbonise the GB power sector.

2 Introduction

2.1 Background

Ofgem launched Project TransmiT, which is its review of transmission charging and associated connection arrangements, with a call for evidence on 22 September 2010. The objectives of Project TransmiT are to ensure that transmission charging "facilitates timely transition to a low carbon energy sector which continues to provide safe, secure, high quality network services at value for money to existing and future consumers".

In scope of Project TransmiT are all aspects of the current electricity transmission charging regime, ie Transmission Network Use of System (TNUoS) charges, connection charges, allocation of transmission losses as well as other aspects of the current connections arrangements. Issues related to enduring reform of the electricity transmission access arrangements as covered in the Transmission Access Review (and the recent implementation of the Connect & Manage access regime by the Government) are out of scope of the review[1].

Ofgem's call for evidence has attracted a wide range of responses and views and a range of possible transmission pricing models have been proposed. A number of participants have estimated, or are currently trying to assess, the impact of the alternative policy options being considered and examine the impact of different transmission charging options (eg "postalisation", locational TNUoS) as well as different energy market arrangements (eg Locational Marginal Pricing – "LMP"[2]) on the electricity system.

In particular, there is a desire to develop a better understanding of the interaction between different models for transmission charging, energy trading arrangements, and the decisions of generators in locating new plant and making retirement decisions, and the impact in turn of these decisions on transmission investment. In order to undertake cost benefit analysis of the different models, an approach is required whereby future generation investment and plant retirements and transmission expansion are endogenous to the analytical framework, ie they are outputs rather than input assumptions. However, endogenous generation and transmission investment modelling is a non-trivial exercise, when combined with alternative transmission charging models, given the interdependencies between the investment and retirement decisions. Therefore a number of different modelling and analysis approaches are possible and indeed have been taken.

In this context, NERA Economic Consulting and Imperial College London were commissioned by RWE npower ("RWE") to compare the current system of locational TNUoS charging for power generators (the "Localised Scenario") with a system of uniform generator charges (the "Uniform Scenario"). Their report, "Project TransmiT: Impact of Uniform Generation TNUoS, Prepared for RWE npower" was published on 31 March 2011. For clarity, this Uniform Scenario is significantly different from the uniform model proposed by Scottish and Southern Energy Plc ("SSE"). This review does not consider the SSE model, rather it considers only the uniform model critiqued by NERA/Imperial.

[1] Energy imbalance (cash-out) charges and distribution network charges are also out of scope of the review.

[2] Locational Marginal Pricing (LMP) is a model based on determining locational spot energy prices. Difference between spot energy prices at different locations would be designed to reflect the cost of congestion and transmission losses.

2.2 Scope of work and approach

SSE has asked Redpoint to undertake an independent peer review of the NERA/Imperial work. It is inevitably the case that simplifications are required when undertaking analysis of this complexity, and this review is not intended to critique in detail the modelling methodology adopted which we believe to be broadly sound and thorough given the challenges involved. Rather, the objectives of the review are:

- to place in context the options analysed within the range of alternative transmission charging models,
- to highlight where limitations of the modelling methodology may influence the conclusions being drawn,
- to identify specific scenario assumptions that may materially be affecting the outcome of the cost benefit analysis (CBA), and
- to assess whether the scenario assumptions modelled are representative of a "central" case.

We have not been asked to undertake a quantitative benchmarking of the NERA/Imperial results or to undertake our own independent economic analysis. Thus, this peer review is based solely on the contents of the NERA/Imperial report and our assessment of the methodology, key assumptions and results. We have, however, supported our assessment with approximate quantification where possible using the data and information available in the published NERA/Imperial report.

2.3 Contents

We structure our review as follows:

- In Section 3, we consider the various models for transmission charging proposed by industry and academia. We assess how the scenarios analysed by NERA/Imperial relate to the range of possible options to place the conclusions of the study in context,
- In Section 4, we review the methodology adopted and the assumptions used in the NERA/Imperial study to assess how representative the results are of a "central" case, and to what extent the analysis may over- or under-estimate the benefits of the Localised Scenario over the Uniform Scenario, and
- In Section 5, we summarise our conclusions.

3 Review of transmission charging models

3.1 Introduction

At the outset, it is instructive to put the proposed transmission charging models analysed by NERA/Imperial in the context of the options being considered by the Project TransmiT review. It is important to note that there is a full spectrum of options, including many variants on the Uniform Scenario. The conclusions of the NERA/Imperial study are that the current Localised Scenario is preferable to *one* variant of the Uniform Scenario. The two scenarios modelled represent perhaps the widest span of potential options that are consistent with the current energy trading arrangements (ie excluding LMP). Indeed, we should expect the Localised Scenario to appear preferable on the grounds of economic efficiency, particularly as the analysis ignores any potential benefit from more uniform models relating to the speed of renewables deployment. However, it is important to recognise that the cost benefit analysis (CBA) of other options, including variants of the Uniform Scenario, may be more favourable (or less unfavourable) and hence it cannot be concluded from this analysis alone that a continuation of the existing Localised Scenario is the preferred solution for transmission charging given the ambitious objectives to decarbonise the power sector.

3.2 Assessing the range of transmission charging options

Transmission charging has been an issue for extensive discussion (and controversy) in the industry since privatisation, and the current review is an extension of that ongoing debate. A wide range of models have been proposed by industry and academics and whilst there is some agreement on the key issues and the elements of a successful model, there are a number of differing views on the strategic priorities and objectives for a future transmission regime. These include:

- promoting economic efficiency, including providing the right balance between short run and long run investment signals, and encouraging efficient investment and operating decisions by the transmission companies, generation companies and consumers such that the overall cost of electricity is, as far as practicable, minimised,
- the priority (or otherwise) to be given to renewables targets and decarbonisation targets,
- the risks of polluting transmission charges with other elements of policy (such as renewables support),
- compatibility with EU directives and regulations,
- consistency with the future integration of energy markets across Europe,
- promoting security of supply, and
- practical implementation considerations, including simplicity, cost of implementation, and support from a wide body of stakeholders such that implementation is not unduly delayed.

There are three key design principles to be considered, namely:

- **Cost reflectivity**, including whether charges are locational or non-locational, reflect short run costs or long run total investment costs and whether they are levied on a capacity or energy basis.
- **Influencing participant behaviour and response through signals**, including whether charges are levied on generation versus demand, are locational or uniform, and fixed ex-ante or variable.

- **Stability**, including whether charges are fixed for some period ex-ante or variable, the extent to which they reflect short run costs which are inherently more volatile (although long run costs such as transmission investment are lumpy by nature) and whether they are capacity or energy based.

As we noted earlier, to analyse the costs and benefits of different transmission charging options, a good representation of the interaction between different models for transmission charging and market arrangements and decisions of generators in locating new plant, making retirement decisions and the impact of these decisions on transmission investment is required. These decisions will be influenced by the sum total of the locational and non-locational costs to which generators are exposed and the design of the charges which then apply these costs. Based on the principles discussed above, we can identify the following five design parameters for transmission charging:

- Locational versus non-locational,
- Peak capacity versus output-based,
- Charged on generation or demand,
- Reflective of long run costs (transmission investments) or short run (operation), and
- Fixed versus variable charge.

We illustrate in Table 1 below, at a high level, how decisions around these key design issues would influence key generation and transmission decisions and thus the overall cost benefit analysis.

Table 1 Transmission charging design parameters and their implications

	Implications of design (a)	Implications of design (b)	Comment
(a) Locational versus (b) Non-Locational	Economic efficiency in long run investment decisions to generation, demand and transmission and in short run system operation (including both generator and demand side response). Can create volatility and unpredictability, particularly under real time and nodal locational regimes or when re-zoning is undertaken. Analytically this can reveal itself through small changes in charges apparently having disproportionately large effects on generation siting decisions. Can discourage renewable investment in areas of greatest resource potential since these are typically furthest from load centres and hence have highest transmission charges. Where it is not economic for generators to respond to locational transmission signals (for example, due to renewable resource availability, planning, cooling water or other reasons) then locational transmission signals provide no economic benefit in terms of influencing build decisions.	Generation will site wherever resource potential for renewables or fuel availability and costs are lowest subject to overall economics, transmission capability and planning allows Generation/demand decisions drive transmission investment.	There are sound economic arguments in favour of a locational charge. However, it is difficult to identify locational long-run costs with precision. This coupled with changes in energy policy can lead to the economic benefits of "locational" charging not being realised in practice resulting in simply cost differentials between players located in different areas. Conversely it could be argued that it is right to charge generators based on the real costs that they impose on the system. If moving to a flat charge, it may make more sense to place all charges on demand.

	Implications of design (a)	Implications of design (b)	Comment
(a) Peak capacity versus (b) output-based	Assumes network needs to be able to accommodate peak generation so capacity-based charge is more appropriate and this will better influence investment decisions. Disadvantages low load-factor generators, particularly renewables whose maximum output may not coincide with system peak.	Significant cost saving for low load factor plant which will impact investment decisions. Allows for sharing of capacity between dispatchable and intermittent generation sources for greater overall more efficient resource usage (and potentially some avoided investments), albeit on a non-firm basis. Output-based charge may incentivise capacity hoarding. Network does not need to be designed to meet full transmission entry capacity of connected generation in all cases (though of course, security standards will determine the precise design of the system) so there is potential for overall lower investment.	Capacity-based charge may be more cost-reflective overall (of building the network to cope with peak flows) but there may be cost savings from low load-factor plant which should be taken into account.
(a) Charge on generation versus (b) demand	Generators are better able to respond to locational signals and hence logic for generation to share costs. The precise rationale for the current split within Investment Cost Related Pricing (ICRP)[3] has been challenged by a number of parties.	Demand least able to respond to locational signals. No short or long run investment signals for generation.	If moving to a flat charge it would make sense to levy more / all of the charge on demand – however if retaining a locational signal at least some should be on generation otherwise signal is likely to be ineffective.
(a) Reflective of long run costs (transmission investments) or (b) short run (operation)	Cost reflectivity of long run transmission charges. Effective signals for generation and demand siting if costs can be efficiently reflected in the charges, and locations (zones) can be kept relatively stable.	Potentially volatile price signals (via, LMP, for example) but efficient pricing of short run operating costs of transmission (losses, congestion). Potentially strong, but volatile, signal for long term investment. Limited response capability of demand to short run signals.	The additional short run costs of congestion are currently socialised under the Connect and Manage scheme in place.
(a) Fixed versus (b) variable charge	Stable investment signal. Efficiency of signal depending on relationship between investment costs and the fixed charge.	Challenging to predict and respond to. Risk management framework required.	(b) can result in asset stranding if underlying market drivers change in an unforeseeable way (such as move to high renewable energy targets)

[3] ICRP is the methodology currently used by National Grid to set TNUoS charges in a manner that tries to reflect the marginal costs of transmission infrastructure in a given zone. The current generation/demand split is 27:73.

3.3 Possible impact of alternative models

In the context of the design issues discussed above and having reviewed the evidence submitted to the Project TransmiT call to evidence to date, it is clear that a very wide range of possible models could be considered. To put the Uniform Scenario analysed by NERA/Imperial in context, Table 2 below illustrates the range (although by no means all) of possible models.

Table 2 Alternative transmission charging models

	Use of system charges for long run transmission investment	Local asset charges	Connection charges	Balancing services	Losses
Postage stamp (capacity based) as analysed by NERA/Imperial as the Uniform Scenario	Flat, capacity based	Socialised	Shallow	Socialised	Average, non locational
Postage stamp (energy based)	Flat, energy based	Socialised	Shallow	Socialised	Average, non locational
Postage stamp (energy or capacity based) with local asset charges and locational losses	Flat (capacity or energy)	Asset specific	Shallow	Socialised	Marginal, locational
Postage stamp (energy or capacity based) with locational short run transmission costs	Flat (capacity or energy)	Socialised	Shallow	Targeted congestion costs	Marginal, locational
Augmented ICRP with locational losses	Investment charging approach	Asset specific	Shallow	Socialised	Marginal, locational
Refined ICRP	Energy element	Asset specific	Shallow	Socialised	Average, non locational
Current ICRP and related elements as analysed by NERA/Imperial as the Locational Scenario	Locational, incremental investment cost	Asset specific	Shallow	Socialised	Average, non locational
Augmented ICRP with localised congestion charges and losses	Investment charging approach	Socialised	Shallow	Locational congestion charge	Marginal, locational
Locational Marginal Pricing (LMP) with shallow connection	FTRs[4]/Residual charge	Socialised	Shallow	Marginal, locational	Marginal, locational

[4] Financial Transmission Rights (FTRs). FTRs have the potential to underpin long term revenue streams for the transmission owners in LMP markets and long term transmission rights for buyers. They are financial contracts that entitle the holder to cashflows based on the hourly difference in power prices between specified points of injection and withdrawal. They can create a hedging mechanism that helps to achieve greater price certainty for market participants delivering energy across the system.

	Use of system charges for long run transmission investment	Local asset charges	Connection charges	Balancing services	Losses
Locational Marginal Pricing (LMP) with deep connection	FTRs/Residual charge	Asset specific, deep		Marginal, locational	Marginal, locational

The table indicates that the completely flat, capacity based uniform charging model considered by NERA/Imperial is at the extreme end of the level of socialisation, and is not widely advocated within the industry. Models that strengthen the locational signals within the umbrella of a Uniform Scenario would reduce the apparent benefits as calculated within the NERA/Imperial analysis of retaining the current Localised Scenario. For example, it is possible that a uniform transmission use of system charge could be combined with a package of other measures which retain locational elements or supporting measures on a short run and long run basis, including[5]:

- continued local asset charges,
- implementation of locational marginal losses factors, and
- a move to output based charging, which whilst not strictly speaking a uniform versus locational issue, would be complementary to a uniform based charge.

As an example we illustrate, in Table 3 below, the potential impact of these alternative design choices on the cost/benefit analysis results in reducing the difference between the Uniform Scenario and the status quo Localised Scenario.

[5] It should be noted that following on from recent Ofgem announcements, the focus of TransmiT has now become charging for the provision of transmission assets, i.e. TNUoS.

Table 3 Impact of different design choices on the costs/benefits of the Uniform Scenario

Design choice	Description	Approximate materiality[6]
Local asset charges	Retain local asset charges. Potentially material impact on investment decisions of offshore wind in particular.	High
Locational marginal losses	Locational, marginal loss factors applied to generation and demand would influence short run operating decisions (at the margin), and may influence siting decisions. Will have an impact on short run operation of the transmission system and the magnitude will depend on generation investment decisions. (For example, more generation located further away from demand centres will increase total system losses.)	Medium
A move to output based charging	Significantly lower charges for low load factor plant which could substantially change the economics and investment decisions of onshore and offshore wind.	Medium

[6] This column provides an indication of the impact of the design choice on the costs/benefits of the transmission charging model. For example, a label of "high" materiality for local asset charges would indicate that it has a substantial impact on investment decisions and therefore on the costs/benefits versus models in which no local asset charges are levied.

4 Review of NERA/Imperial analysis

4.1 Modelling methodology

The NERA/Imperial modelling methodology aims to capture the complex interdependencies between generation and transmission investment and transmission charging models. It is based on an iterative approach across a power market model ("Aurora"), the Imperial Transmission Investment Model (DTIM), and National Grid's Transmission Charging Model.

We have conducted a high level assessment based on the information provided in the report. Our major observations (those likely to have a material impact on the cost/benefits shown) are as follows:

- **The methodology is based on iteration and perfect foresight.** We believe that this is a reasonable approach given the complexity of the problem but the limitations of both iteration and perfect foresight need to be recognised when drawing conclusions from the analysis:
  - The iterative approach for converging on a combined generation and transmission investment outcome is highly sensitive to small changes in assumptions, as shown by the sensitivity of the results between iterations to small changes in transmission charges. As a result, the degree of convergence to an "optimal" solution (and indeed how convergence is interpreted) is influenced by user judgement of the results of iterations. NERA/Imperial attempt to address this by averaging the results across iterations. It is not clear that this addresses the underlying issues including the realism of the assumptions made.
  - The perfect foresight assumption detracts from one key potential benefit of the uniform approach, namely that it delivers stable signals for investment in renewables, which could lead to faster deployment and/or a lower cost of capital. This effect may be difficult to capture in modelling terms but it should be recognised.
- **The assumptions used mean that the 2020 renewables targets can be met by *either* model.** Because of this, the possibility that the Uniform Scenario may increase the probability of achieving the 2020 targets by facilitating renewables investment, or at least could lead to the target being met with lower levels of support for renewables, is not considered. Furthermore, it is also necessary to consider renewables ambitions after 2020, particularly in onshore and offshore wind (see the Government's recent acceptance of the 4th carbon budget and the Committee on Climate Change' recent renewables report[7]). No further expansion of renewables is assumed after 2020 in the analysis, and hence there is no potential benefit associated with accelerated deployment after 2020 under uniform transmission charging captured in the modelling framework.
- **The results for consumer benefits are highly dependent on the wholesale price function.** Of the approximate £20bn of reported consumer benefit for the Localised Scenario over the Uniform Scenario, approximately 70% is derived from lower wholesale electricity prices. There is a high degree of uncertainty surrounding how electricity prices will be set in the future under a decarbonising system, and hence the sensitivity of the results to the assumed wholesale price function should be more transparent.

Overall, we believe that the modelling methodology adopted by NERA/Imperial is broadly sound and thorough in an area of modelling which is complex due to the need to model generation and transmission

[7] Implementing the Climate Change Act 2008: The Government's proposal for setting the fourth carbon budget, Policy Statement, May 2011.

investment decisions dynamically. However, we have some concerns that the approach taken does not allow the additional transmission costs associated with the Uniform Scenario to be considered in the context of possible lower costs and faster deployment of renewables, which is key to Government's wider policy objectives. Further, the approach does not sufficiently demonstrate the sensitivity of the results to key assumptions, particularly surrounding the location of new generation and the drivers of electricity prices in the future. In particular, the modelling of generation locational decisions does not take into account practical issues including planning, proximity to resources such as water, and availability of engineering and staff. This outcome however drives subsequent conclusions reached and emphasis given to results regarding losses, congestion costs and wholesale prices. Hence, the headline £20bn consumer benefit of the Localised Scenario is unlikely to be representative of a central scenario.

4.2 Power sector costs

In this section we set out our assessment of the assumptions made by NERA/Imperial in undertaking their analysis of power sector costs. We provide specific comments on the key assumptions that could materially affect the cost/benefit analysis results followed by a tabular summary of the issues identified and their materiality.

4.2.1 Review comments

Overall, it is reasonable to assume that for a given overall generation mix and with very few constraints on the resource potential in given zones (planning, cooling water, fuel transportation, renewable resource, staff and engineering support) power sector costs will be minimised under a locational pricing scenario versus uniform pricing. However, only one scenario has been modelled by NERA/Imperial and, as mentioned above, there is no indication of the sensitivity of the results to key variables. Hence, it is difficult to gauge how representative of a 'central' case the analysis is.

Whilst it was not within the scope of this review to reproduce the analysis, in the specific review comments below we provide a rough quantification, where possible, based on the information in the report. From this high level assessment, we conclude that on balance the results are at the high end of the potential difference in costs between the two models.

SRMC bidding

The analysis assumes that generators bid and offer into the Balancing Mechanism at their short run marginal costs (SRMC), thus ignoring dynamics costs and any scarcity pricing. This will tend to lead to an underestimation of constraints costs, all other things being equal.

When the resolution of transmission constraints primarily involves coal and gas plant, the SRMC differentials between constrained off and on plant can be relatively small. We note that constraint costs for 2010-13 modelled by NERA/Imperial (Figure 4.18) appear to be to an order of magnitude below the recent outturn annual constraint costs reported by National Grid. This implies that the assumption of zero bid-offer discounts and premia in the Balancing Mechanism materially understates constraint costs, at least in the early years of the modelling horizon.

Transmission investment costs

The analysis uses the lowest cost estimate that National Grid uses within the DTIM model. This may lead to transmission investment costs at the low end of the plausible range thus reducing the differences between the scenarios.

Transmission investment timing

The NERA/Imperial analysis assumes that transmission is built as soon as the modelling suggests that it is required and economic which may lead an underestimation of overall costs (investment plus constraints), other things being equal.

Impact of connection policies

Whilst the analysis assumes that National Grid is able to influence the siting of plant under the Uniform Scenario through its connections policy, the effect could be greater than assumed. If the influence was greater than assumed, then the NERA/Imperial analysis will tend to overstate the additional transmission costs under the Uniform Scenario. For example, at least partly due to the potential local connection costs and works (amongst other reasons explored below), we believe it very unlikely that so much new CCGT capacity would be built in Scotland under the Uniform Scenario or as much built in South East Zone 17 under the Locational Scenario.

Generation mix and build

The NERA/Imperial analysis results in a carbon intensity of around 200 g/kWh by 2030 under both transmission charging models. (No policies for promoting renewables or other forms of low carbon generation after 2020 are assumed.) This 200 g/kWh figure is greater than the 100 g/kWh assumed in the analysis supporting the Electricity Market Reform (EMR) Consultation. It is also significantly greater than the 50 g/kWh recommended by the Committee on Climate Change (CCC) in its 4th Budget Report. The Government recently accepted the CCC's recommendation for the 4th carbon budget (2023-2027), which suggests that a target carbon intensity from the power sector in 2030 closer to 50 g/kWh may be more likely.

By modelling a scenario with less carbon reduction assumed, more conventional fossil fuel plant, whose siting is more sensitive to locational transmission charging signals, is required. The siting of renewables, nuclear and carbon capture and storage are more strongly influenced by other site specific factors. Hence, the difference between the two models in terms of transmission costs is probably greater than would be the case under scenarios with higher levels of decarbonisation.

Also, as mentioned above, the modelling methodology does not consider any potential benefit of the Uniform Scenario in accelerating the rate of decarbonisation. In addition it assumes that the charging scenario has no impact on the cost of capital that will be applied to new generation investments. Locational charging is inherently less certain than uniform and so it would be reasonable to assume a higher discount rate should be used.

The model also appears to allow unconstrained build in a preferred zone(s) ignoring practical difficulties such as obtaining a sufficient number of suitable sites, planning or cooling water constraints. Furthermore, relatively small differences in underlying locational costs appear to result in wholesale shifts of investment decisions between zones for which there is often no clear explanation. For example in the Locational Scenario, over 20 GW of CCGT and OCGT are built in South East Zone 17. Similarly in the Uniform

Scenario, 12 GW of CCGT and OCGT are built in Scotland. There is no clear rationale for these choices. The report itself says "the differences in NTS exit charge that drive the model to locate virtually all new capacity in Scotland are relatively small". Gas transmission system exit charges for Bacton are as cheap as those in Scotland. A feedback between the location decision and the locational signals received from transmission and gas charging does not appear to have been incorporated in the modelling.

Nuclear build appears to be higher in the Uniform Scenario by 1.6 GW, according to Tables G3 and G4. It seems, however, unlikely that transmission charging policy will be a determining factor in the overall amount of nuclear built, particularly when the levels for contracts for differences under EMR are yet to be set. Hence, differences between the two charging models relating to different levels of nuclear deployment should be discounted. It is not clear whether this additional capital investment leads to a net increase or decrease in overall power sector costs under the Uniform Scenario.

Nuclear build appears to be concentrated entirely at Wylfa (Zone 11) in the Locational Scenario. This seems an unlikely outcome given the range of sites where projects have been proposed. Moreover, the outcome appears inconsistent with the modelled TNUoS charges in this scenario. The nuclear sites developed in the Uniform Scenario (Zones 15, 17 and 19) all have lower TNUoS charges, at present and as modelled in the Locational Scenario.

The NERA/Imperial analysis assumes that generation is built as soon as the modelling suggests that it is required and economic which is likely to lead to an overestimation of overall transmission costs (investment plus constraints), all other things being equal.

Finally, it is unclear from the analysis how plant retirement decisions are determined.

Renewables mix

The NERA/Imperial analysis assumes the same level of renewables support under the two scenarios, ie the level of renewable support is not reduced under the Uniform Scenario despite lower transmission charges on average. This leads to greater amounts of offshore wind under the Uniform Scenario leading to higher power sector and consumer costs. However, the Government's renewables policy is designed to promote a range of technologies to stimulate learning and generate diversity, and not necessarily to incentivise the cheapest prevailing technologies. Given these objectives, it is not valid to ascribe any dis-benefit to the Uniform Scenario by delivering more offshore wind (and the Government could always control this by adjusting renewable support levels should this become a concern).

Gas transportation charging

A significant proportion of the additional transmission costs under the Uniform Scenario is associated with more CCGTs located in Scotland. This seems a very unlikely outcome since gas exit charges are not currently systematically lower in Scotland. National Grid's April 2011 NTS charging statement shows that there are several sites in the East of England or South Wales with exit charges as low as St Fergus in Scotland. Further, the level of CCGT investment assumed in Scotland resulting from the model under the Uniform Scenario would likely lead to higher exit charges in Scotland thus moderating the amount of thermal plant investment in Scotland. In addition, the wider planning and consenting framework needs to be considered. For example, large volumes of new CCGT generation may be inconsistent with current Scottish Government policy. Hence, the higher transmission costs under the Uniform Scenario are likely to be an overestimate.

We estimate that of the additional £7.6bn of power sector costs under the Uniform Scenario, approximately £5.2bn could be associated with the large volumes of gas-fired capacity (CCGTs and OCGTs) that the model builds in Scotland and the high volumes of gas plant built in Zone 17 in the Locational Scenario which are in reality very unlikely to transpire due to other issues that determine new power station location

Constraint costs

As identified earlier, the SRMC bidding assumption made would tend to underestimate constraint costs, as would the modelling assumption that transmission reinforcements come in immediately when economic. This explains why constraint costs in the early years are low and the impact of the Uniform Scenario in increasing constraint costs may be underestimated. However, there is a significant increase in constraint costs in later years. It is not very clear what is causing this but we assume it relates to high volumes of renewables being bid down through the Balancing Mechanism, with the renewables plant assumed to bid in the opportunity cost of forsaken ROC revenues. Arguably, lost renewables support revenues are not 'real' constraint costs and should this become an issue other measures may be put in place to reduce the impact. Furthermore, under the proposed Contracts for Differences the bidding incentives for renewables plant may change. Prior to the publication of the White Paper, this remains an uncertain policy area. However, it would be useful to understand better what proportion of the higher constraint costs reported for the Uniform Scenario and a function of the assumed bidding behaviour of renewables (and other low carbon plant).

In considering the realism of the scenarios, we also need to consider the likelihood of building large volumes of generation in one zone such as in the Locational Scenario with over 20 GW of CCGT and OCGT capacity being built in Zone 17. CCGT and OCGT plant account for 90% of the incremental capacity in Scotland under the Uniform Scenario (Tables G3 and G4), with wind representing only 10% of the increase. This suggests that the high concentration of gas-fired capacity in Scotland may be responsible for up to approximately £1.4 bn of the additional transmission constraint and investment costs reported under the Uniform Scenario. This effect could be further over-estimated by the unrealistic deployment of thermal plant in Zone 17 in the Locational Scenario. Overall, constraint costs are very sensitive to input assumptions. The SRMC bidding assumption described above is likely to lead to underestimated constraint costs. However, the assumptions on generation mix (and resulting very high levels of CCGT build in Scotland under the Uniform Scenario and the high levels of CCGT build in zone 17 in the locational scenario) are likely to overestimate constraint costs in the Uniform scenario relative to the locational scenario. On balance, we consider that the difference in constraints costs between the two scenarios is at the high end.

Losses

A significant proportion of the higher losses under the Uniform Scenario are also likely to be associated with the amount of CCGT build modelled in Scotland versus Zone 17 under the Localised Scenario. Incremental baseload to mid-merit plant in Scotland drive a large proportion of the additional transmission losses reported under the Uniform Scenario. Applying load factors of say 60% for CCGTs, 30% wind and 10% for OCGTs, gas-fired capacity would account for 92% of the incremental generation output in Scotland under the Uniform Scenario. This generation output share would translate to £3.8 bn of the additional transmission losses (although the report states that offshore wind farms partly account for incremental losses).

Finally it is unclear whether the analysis takes into account lower loss factors on the additional new transmission capacity built under the Uniform Scenario which would moderate the higher losses.

Interconnectors

It is unclear what assumptions have been made with respect to future interconnection capacity. Increased interconnector capacity in the South of the country would likely mitigate the risks of more plant being sited in the North of the country under the Uniform Scenario, and hence lower the amount of additional transmission costs as well as potential reducing overall constraint costs depending on constraint boundaries.

Investment risk

The analysis takes no account of the potential benefit of stable and predictable TNUoS charges for investment decisions. It is possible that the Uniform Scenario could lead to lower investment risk and hence a lower cost of capital. For every basis point reduction in the cost of capital, the impact on the total cost on an NPV basis would be around £50m on 30 GW of wind investment. This potential benefit of the Uniform Scenario should be considered.

Others

Several transmission reinforcement projects have already been approved or are in advanced planning. However, if these known projects are excluded and all transmission investments are optimised by the model, the analysis may overstate the reinforcement related cost differences between the two scenarios.

4.2.2 Summary

Table 4 below summarises the key variables underpinning the analysis of power sector costs and whether we consider the assumptions made in the analysis have tended to over or under-estimate the differences between the Uniform and Localised Scenario. We also give an approximate indication of materiality. From this high level assessment, we conclude that on balance the results are at the high end of the potential difference in costs between the two models.

Table 4 Assumptions influencing power sector costs

Area	Over/under estimate	Approximate materiality
SRMC bidding	Under	Medium
Transmission investment costs	Under	Medium
Transmission investment timing	Under	Low
Impact of connection policies	Over	Low
Generation mix and build	Over	High
Renewables mix	Over	High
Gas transportation charging	Over	High
Constraint costs	Over	Medium
Losses	Over	High
Interconnectors	Over	Low
Investment risk	Over	Low

4.3 Consumer costs

In this section we set out our assessment of the assumptions made by NERA/Imperial in undertaking their analysis of consumer costs. Again, we provide specific comments on the key assumptions that could materially affect the cost/benefit analysis results followed by a tabular summary of the issues identified and their materiality.

4.3.1 Review comments

Notwithstanding the cyclical nature of electricity prices and variability in energy company margins, it can reasonably be assumed that any additional costs in generating and transporting electricity resulting from a particular policy will, over the longer term, be reflected in higher consumer prices. However, the increase in consumer costs produced by the NERA/Imperial analysis is over £13bn greater on a net present value basis than the increase in power sector costs. This suggests a sustained increase in generator margins which would likely only occur if there was a decrease in the competitiveness of the market. The difference relates primarily from the modelling result (and associated underlying assumptions) that wholesale electricity prices are significantly higher under the Uniform Scenario and that renewables support costs are also higher under the Uniform Scenario, despite presumably lower investment costs for renewables in general.

We expand on both these points below.

Wholesale energy costs

We have identified the following potential issues with the wholesale price results on the basis of the information provided in the report:

- It is not immediately clear what is driving such large differences between wholesale prices in the two scenarios when section 5.3.1 of the NERA/Imperial report suggests there is a very similar capacity mix between the scenarios.
- There are a few areas that are difficult to explain, for example, why the generation costs are higher under the Uniform Scenario between 2012 and 2016 but the wholesale electricity prices are in fact lower.
- There is not a strong relationship between price and de-rated capacity margins. For example, the de-rated capacity margin falls negative under the Uniform Scenario in 2024 but the wholesale price does not seem to react (and the unserved energy volumes are very low).
- The NERA/Imperial methodology appears to base electricity prices on the long run marginal cost of new entrant CCGTs, and hence the increased transmission charges experienced by the new entrant CCGTs in the Uniform Scenario translate directly into higher electricity prices. Thus a very large part of the wholesale cost conclusion is directly dependent on the location assumption and the assumption that these additional costs pass straight through. The interaction between new entrant cost recovery and wholesale prices is not clear at present and needs additional careful consideration in worlds with higher levels of decarbonisation where gas plant will play a decreasing role in price setting.
- It is unclear how LCPD/IED constraints are being handled with regard to their impact on wholesale price (although experience of 2008 showed that the impact could be large). Section 3.3.1 of the NERA/Imperial suggests that annual constraints are not handled by the model.

- Wholesale prices are very sensitive to commodity price assumptions and there are no sensitivity tests (for example, on coal/gas price differentials). Also, the analysis (as the report recognises) pre-dates the Carbon Price Support announcement.
- As is the case for losses and congestion costs, the wholesale price increase flows from the initial premise that 12 GW of gas plant will locate in Scotland in the Uniform Scenario and 20 GW of gas plant will locate in Zone 17 in the Localised Scenario.

Of the £20bn increase in consumer costs under the Uniform Scenario, around 70% is attributed to higher wholesale electricity prices. There are many factors that determine wholesale electricity prices and caution must be used in basing conclusions on a single projection. Given this, a very high degree of caution should be applied to the results given the sensitivity of wholesale electricity prices to assumptions and this should have been recognised much more explicitly in the report.

Furthermore, the divergence in increased costs to consumers (£20bn) and increased generation costs (£8bn) between the two models, suggests a significant increase in the profitability of the sector which is high and which may not be sustainable.

Renewable support costs

The NERA/Imperial analysis suggests that renewable support costs would be higher rather than lower under Uniform Scenario. This seems a counter-intuitive outcome, since on average transmission charges would be lower for renewable plant and hence support levels could be reduced accordingly. Furthermore, since the analysis suggests that wholesale electricity prices would be higher under the Uniform Scenario this should allow renewable support levels to be cut back further.

Under the same broad modelling assumptions and results, we assume that renewables support could in theory be cut back under the Uniform Scenario whilst still achieving the same level of deployment as the Localised Scenario to reflect:

- **Lower local asset charges.** On an NPV basis we calculate this to be a saving of between £3.1 bn and £3.7 bn, based on the estimate of avoided offshore transmission charges for the modelled offshore wind capacity.
- **Lower wider TNUoS charges.** On an NPV basis we calculate this to be a saving of at least £500m (based on the TNUoS charges in Tables F1 and F2 and the zonal wind capacity in Tables G3 and G4).
- **Higher wholesale electricity prices (assuming that this is correct)**. On an NPV basis we calculate this to be a saving of around £500m in the case of the modelled offshore wind capacity (as an example only), based on the average wholesale price differential of £2/MWh from 2020 (assuming this differential is correct).

Also, for the reasons outlined above it cannot be assumed that the Uniform Scenario necessarily leads to more offshore wind, and so these additional support costs should be discounted. However, although the report says there is more offshore wind under the Uniform Scenario, it is not clear how much from the charts and tables. Indeed, the bar charts in Figure 4 appear to show the same modelled offshore wind capacity in 2030 (to the nearest 250 MW), the only difference being the switch of around 2.5 GW capacity from 'S/SW England' to 'E England'. Hence, it is difficult to quantify this effect.

Aside from the possible costs associated with more offshore wind, we estimate that in total the level of renewable supports costs could be £4bn-£5bn lower on a NPV basis under the Uniform Scenario (given the modelling assumptions), compared to a reported £262m increase.

4.3.2 Summary

We summarise the issues in respect of consumer costs in Table 5 below.

Table 5 Assumptions influencing consumer costs

Area	Over/under estimate	Approximate materiality
Renewable support costs	Over	High
Wholesale energy costs	Over	High

5 Conclusions

Our overall assessment is that the assumptions used lead to exaggerated potential benefits of localised versus socialised transmission charging models and the report as a whole does not adequately represent the range of likely outcomes or key sensitivities. The Uniform Scenario chosen, with postage stamp charges and no separate local asset charges, is at the extreme end of the level of socialisation. Hence, the results cannot be assumed to be representative for all variants of the Uniform Scenario. For example, uniform TNUoS charging could be combined with local connection charges and other locational signals such as zonal loss factors. The overall costs of these variants will be much less than those reported for the Uniform Scenario as modelled by NERA/Imperial. Furthermore, the analysis does not set the additional costs of uniform charging models against the potential wider economic benefits of more rapid electricity system decarbonisation. We believe that the fact the two models considered produce the same levels of renewables deployment is a function of the assumptions used and the modelling methodology, and this potential benefit of uniform models has therefore not been sufficiently considered.

Overall we believe that the modelling methodology used is sound, notwithstanding the simplifications that are needed for a piece of analysis of this complexity. However, the results are very sensitive to the assumptions used, and with only one case modelled it is not easy to get a sense of how representative the results are of a 'central' case. In particular, other factors, not related to transmission price signals, that affect siting decisions such as planning constraints, cooling water access and local availability of staff and engineering resources, have not been considered. As a result the divergence in outcomes for location of plant under the two scenarios modelled is extreme from which it is not prudent to draw strong conclusions about the models and their comparative costs. Gas plant location appears to be driven by relatively small differences in underlying locational costs, resulting in large shifts of investment decisions. As a result, in the Uniform Scenario, 12 GW of gas plant locates in Scotland and in the Locational Scenario, 20 GW of gas plant locates in the South East Zone 17. We believe that this is not representative of a central case and since increases in wholesale price congestion, losses and transmission infrastructure costs between the scenarios appears to flow from this initial premise, we believe significant caution should be applied to the benefits attributed to the localised model.

Based on our assessment, we challenge the credibility of some of the assumptions made and believe that overall they have produced a result, an increase in consumer costs of £20bn NPV, which is at the very high end of possible increase in costs under the Uniform Scenario analysed and to which a very high degree of caution should be applied. We believe that a significant proportion (around £5.2bn) of the additional £7.6bn of power sector costs reported for the Uniform Scenario is associated with the large quantities of new CCGT and OCGT built in Scotland by the model compared to large quantities of CCGTs and OCGTs built in Zone 17 in the Localised Scenario, and are therefore unrelated to the connection of renewables in remote locations. We believe that this is an unlikely outcome and not representative of a central case.

The extent to which consumer costs increase more than power sector costs (£19.8bn compared to £7.6bn) seems high and/or potentially unsustainable. Approximately 70% of this additional cost is associated with higher wholesale electricity prices under the Uniform Scenario. We do not believe the sensitivity of the results to the assumptions around wholesale price setting has been sufficiently explored and any reduction in the difference in wholesale price between Uniform and Locational scenarios would result in a much lower impact on consumers. Furthermore, we estimate that renewables support costs could be £4bn-£5bn lower under the Uniform Scenario, given lower costs for renewable generators, which would also significantly reduce the impact on consumers.

Therefore, we believe that on the basis of the scenarios chosen and the assumptions used, it is not possible to conclude that retaining the current transmission charging regime is the best option given the ambitious objectives to decarbonise the GB power sector.