UCL ENERGY INSTITUTE

OFGEM'S PROJECT TRANSMIT

A Peer Review of Commissioned Academic Analysis

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Note:

Ofgem commissioned three pieces of academic analysis (by Bell et al, Baldick et al, and Newbery) of proposals relating to transmission charging, and this peer review was initially of the three reports resulting from this commission. Ofgem then commissioned a fourth piece of analysis (by Baker et al) and asked that this peer review should also include the extra report that resulted. The fourth piece of analysis had different objectives (and itself contained a review of the original three academic reports). Comments on this fourth report have been added to the end of the peer review of the three original reports, and to reflect the discussion of the original peer review in this extra report.

Objectives, Principles and Fundamental Considerations Relating to Project TransmiT

The objective of Ofgem's Project TransmiT is 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"[1].

This objective reflects current government energy policy objectives, which now include:

1. Movement to a low-carbon energy system, in line with the carbon target for 2050 and interim statutory carbon budgets incorporated in legislation. This is widely taken to require early decarbonisation of the electricity system.
2. Considerable increase in the quantity of electricity generation from renewable sources, in line with the target for the UK set by the EU Renewables Directive. This is thought likely to require an increase from the 2009 level of around 7% to around 30% of renewable generation by 2020.
3. Energy security. Unlike the previous two objectives this is not defined in quantitative terms, but is broadly taken to mean that the system capacity margin[2] will be maintained at an adequate level (in the context of the changing mix of generation required to meet the first two objectives) to ensure that electricity demand is met in line with current performance standards.
4. Affordability. It is acknowledged that the achievement of objectives 1-3 will require electricity prices to rise. They are therefore in tension with this objective. Given the statutory nature of objectives 1 and 2, and the political imperative of achieving objective 3, this objective may be interpreted as one of cost-effectiveness, to ensure that the first three objectives are met at something approaching least cost.

Although Ofgem's Call for Evidence for Project TransmiT covers both electricity and gas, the focus of the academic work that is the subject of this peer review, and therefore of this peer review, is electricity.

In the context of transmission charging, a number of sub-objectives may be defined, such as[3]:

- Efficient participant behaviour (related to objective 4)
- Efficient grid behaviour (related to objective 4)
- Cost reflectivity (related to objective 4)
- Public good reflectivity (related to objectives 1,2,3)
- Non-discrimination (related to objective 4)
- Stability, predictability, transparency, robustness (related to all objectives because investment risk, and therefore cost, is reduced)
- Administrative simplicity (favours smaller actors and objective 4)

[1] Ofgem 2010 'Project TransmiT: A Call for Evidence', September 22, p.1
[2] System capacity margin is the generating capacity on the power system in excess of that required to meet peak demand, to be available in case of unexpected outages of generating capacity due to malfunction, accidents or other reasons
[3] The following list is taken from Pöyry Energy Consulting 2010 'Electricity Transmission Use of System Charging: Theory and International Experience', a Report to EDF Energy, November

This list makes clear the tension noted above under objective 4, that the sub-objectives related to affordability (i.e. reducing costs) tend to be quite distinct from those oriented towards low-carbon generation and energy security.

Ofgem's Call for Evidence sets out the three elements of current transmission charges:

1. Connection charges (£150m in 2010/11), for the provision and maintenance of connection assets: since the introduction of an extremely shallow charging regime about 10 years ago, transmission connection assets have reduced significantly relative to the previous 'deep' regime and now represent a small proportion of generators' costs when connecting to the transmission network. Following a government decision in mid-2010, connection has been organised on a 'connect and manage' approach, whereby connection may follow initial 'enabling' work before the completion of the reinforcement of the wider network, and may therefore enable operation to some extent before this full reinforcement has taken place. This change in approach has not materially affected connection charges;

2. Transmission Network Use of System (TNUoS) charges (£1,600m in 2010/11): these are based on power (rather than energy) flows and have a locational element for both generation and load (or demand) and vary according to the extent of transmission required for the plant concerned (generation furthest from load, and load furthest from generation, pay most in charges to reflect their higher transmission cost). For generators the locational element, which is grouped into zones, is intended to cover "the zonal average long-run forward-looking costs of connecting an incremental megawatt (MW) of generation at a given point on the transmission network" (Call for Evidence, Technical Annex, pp.3-4). In total the locational element accounts for about 16% of the revenues, with the rest deriving from the non-locational 'residual' charges[4], while the charges overall are split 27% to generation and 73% to load;

3. Balancing Services Use of System (BSUoS) charges (£800m in 2010/11): these cover the costs of the day-to-day operation and balancing of the network. In the UK at present BSUoS charges are non-locational, based on energy (rather than power), and levied 50/50 on generation and demand. The operational costs incurred in accommodating the connection of generation under a connect and manage approach (i.e. before full reinforcement of the wider network is complete) will be shared across generators and suppliers through the BSUoS charge.

Thus the connection charges seek to recover the costs of transmission assets that facilitate connection to the GB transmission system, TNUoS charges are intended to recover the costs of transmission infrastructure assets that facilitate access to the GB transmission system, while the BSUoS charges recover their operational costs. Most attention in the responses to the Call for Evidence and in the academic papers under review has been paid to the TNUoS charges, perhaps because decisions relating to connection charges and BSUoS charges seem unlikely to be changed, and because the TNUoS charges are locational whereas the BSUoS charges are not. For this reason, it is the TNUoS charges that get most attention in this peer review of the papers.

[4] See the academic paper by Bell et al., reviewed later in this paper, Table 2, p.23

The difference in conclusions about transmission charging to which the tension between the objectives may lead is well illustrated in three of the reports which were submitted in response to Ofgem's Call for Evidence on the subject. The report by Pöyry Energy Consulting for EDF Energy[5] argued on more or less conventional economic efficiency grounds for a continuation of locational transmission charging arrangements. The report by Oxera for ScottishPower[6] stressed that locational charging disadvantaged the best onshore GB wind resources, more of which would become economic with flat-rate ('postage stamp') charging, and all of which would be needed to meet the UK renewables targets (objective 2), while that from NERA and Imperial College for RWE npower[7] found that locational charging was economically more efficient and did not prevent the achievement of the Government's renewable targets. It is beyond the scope of this Peer Review to assess the relative merits of or adjudicate between these reports, but the stark difference in their conclusions illustrates the remaining uncertainties surrounding such issues, and the importance of the different assumptions that are made concerning them in arriving at modelling or analytical results.

As will be seen, like many of the responses to the Call for Evidence, a major element of the academic contributions reviewed here is an analysis of the trade-off between these objectives and recommendations as to the appropriate balance to be struck between them. Ofgem's actual remit for the initial three academic contributions stated that Ofgem was "looking for views on:

a) appropriate guiding principles for transmission charging that are consistent with meeting the objectives set out above;

b) the broad building blocks of a suitable target charging model that would best achieve the objectives as a whole, taking into account any trade-off amongst these objectives, for example:

    - economic efficiency vs facilitation of carbon reduction;
    - long-run investment efficiency including both transmission and generation vs short-run operational efficiency; and
    - requirements for a self-contained system vs those relevant for closer integration of other European systems cross-border.

c) the interdependencies between the proposed charging model and other aspects of the regulatory regime for electricity and, where relevant, gas networks, including cross-European regulatory and policy developments. Where possible, the report should also provide views on the extent to which these help or hinder under the existing GB arrangements."

[5] Pöyry 2010 'Electricity transmission use of system charging: Theory and international experience', report for EDf Energy, November.
[6] Oxera 2010 'Principles and priorities for transmission charging reform', report for ScottishPower, November
[7] NERA and Imperial College 2011 'Project TransmiT: Impact of Uniform Generation TNUoS', report for RWE npower, March

Peer Review of Newbery, D. 2011 'High level principles for guiding GB transmission charging and some of the practical problems to transition to an enduring regime'

The paper is in three parts: the longest sets out the economically efficient approach to transmission charging in an efficient world; then there is some discussion of how this approach might be modified in the context of actual sub-optimal policy and market arrangements; the short conclusion is titled 'The Case for Change'.

Newbery summarises his high-level principles of efficient pricing as seeking to encourage:

- "the efficient short-run use of the network (dispatch order and congestion management);
- efficient investment in expanding the network;
- efficient signals to guide investment decisions by generation and load … ; and
- cost-recovery." (p.36)[8]

Newbery's main recommendation for transmission charging that satisfies these principles is nodal Locational Marginal Pricing (LMP)[9], which in its nodal or zonal versions is currently practiced in New England and elsewhere in the US, and which differentiates by location the price paid for electricity, rather than charging for access to the transmission system, as with the current TNUoS locational charges. The electricity price in LMP is made up of three components, which take into account costs related to energy, congestion, and losses. LMP can be complemented by a long-run contract for desired Transmission Entry Capacity, set by a deep connection charge; additional, non-distorting, charges to raise the revenue short-fall, such as peak-load pricing of demand and access pricing for controllable generation; and Financial Transmission Rights (FTRs) to hedge against unpredictable nodal prices. However, Newbery recognises that these recommendations may not be appropriate in the currently distorted market for electricity, and identifies as two of the main distortions the Connect and Manage Socialised Cost (CAMSOC) approach to recovering the operational costs incurred in accommodating the connection of generation that has recently been adopted, and the policies that have been put in place to seek to meet the UK's renewables target under the EU's 20-20-20 climate policy. A less radical, but still locational, alternative to LMP would be the Nordic 'market-splitting' (or market coupling) model, that retains the zonal approach of the current TNUoS charges, and would be consistent with what is being proposed for more integrated European networks.

In general the difficulty with adopting these approaches is that their emphasis on efficiency could disadvantage investment in renewable. As Newbery notes, if renewables targets are to be met, this could require higher subsidies to be provided in other ways, which could be "more or less distortionary than collecting it via higher grid charges" (p.34). This is a particular instance of the more general point that Newbery also makes, that "transmission charging is only part of the task of

[8] On p.19 of his paper Newbery also includes among his principles "legality, fairness and political feasibility", but this fails to make the Summary on p.36

[9] LMP can relate to nodal or zonal spot pricing, with the latter sometimes referred to as 'market-splitting', depending on whether the price is calculated at the node or for a wider zone incorporating more than one node.

ensuring that the electricity system is able to deliver the Government's stated objectives" (p.7), as set out above. An important question is whether transmission charges should be set efficiently and any cost disadvantage thereby introduced, for example to renewables, be offset by increased subsidies elsewhere, or whether the transmission charges themselves should be part of any subsidy package to renewables, allowing lower subsidies elsewhere. Newbery's paper raises the question, but does not answer it.

Newbery's favoured approach, in line with efficiency arguments and as set out briefly above, could be best implemented through substantial reform to current electricity trading arrangements, including central dispatch through a pool and the return to deep connection charging. A shift to the European Target Model for market coupling would be another possibility that would ease integration of the UK into wider European power markets. If this extent of reform is not considered desirable, then another possibility would be to seek to guide the location of future generation investment through the design of the Feed-in Tariffs/Contracts for Difference that have been proposed under the Government's current proposals for Energy Market Reform. One problem in deciding between these options is lack of clarity as to the costs actually imposed now, and possibly to be imposed in the future, by a failure to give locational guidance of the kind proposed. Newbery concludes that getting further insights into these costs and how they might develop with increasing renewables penetration is a priority for further research.

Peer Review of Bell, K., Green, R., Kockar, I., Ault, G. & McDonald, J. 2011 'Academic review of transmission charging arrangements'

The 'high-level principles' for transmission charging offered by this paper are as follows:

"1. They should encourage 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.

2. They should be consistent with the realisation of climate change mitigation targets set by government in the UK

3. They must be compatible with EU directives and regulations

4. They should be consistent with the future integration of energy markets across Europe

5. They should not present undue barriers to the realisation of adequate security of supply

6. They should not be over-sensitive to small changes in the transmission system and its users

7. They should be as simple as possible to achieve their objectives, and no simpler

8. They should command sufficient stakeholder support to be implementable." (p.9)

A notable difference between this list and that of Newbery is the inclusion of UK and EU policy objectives, rather than simply concentrating on economic efficiency and cost recovery. This difference becomes even starker when the paper condenses these principles to an "ultimate objective of a set of trading and transmission arrangements as being to:

"minimise the total costs of electricity in both the short and long-term

subject to

- meeting the 2020 renewable energy targets;
- achieving at least a certain minimum level of reliability of supply." (p.13)

Expressing the problem as minimising the cost of supplying electricity subject to achieving policy targets means that if transmission charging arrangements make achieving these targets more difficult (perhaps by making renewable energy generation in key areas more expensive), other measures to promote renewable energy may need to be made stronger for the targets to be met (as the paper recognises on p.15). These other measures may entail costs. The implication of this is that making transmission arrangements economically efficient may introduce costs elsewhere which need to be taken into account in any overall assessment of the benefits of such transmission charging arrangements.

For their assessment of different methods of transmission charging the paper uses two technical and three practical criteria which are related to, but different from, the high-level principles. These are: technical – economic efficiency and robustness; practical – workability, complexity and stakeholder support (p.16). The paper usefully lists the main dimensions by which different charging methodologies may be differentiated. This is given below as Table 1 (p.20):

Table 1: main charging methodology design dimensions

Locational	↔	Non-locational
Levied on Generation	↔	Levied on Demand
Power based (measured by MW)	↔	Energy based (measured by MWh)
Based on long-run costs	↔	Based on short-run costs
Recovery of cost of transmission assets and their maintenance	↔	Recovery of cost of operating the system
Fixed charges	↔	Variable charges
Based on typical reinforcements and their costs	↔	Based on notional or average reinforcement costs

One important omission from this list is the distinction between locational transmission charges (as with the current locational element of the TNUoS charges) and incorporating the differential costs of transmission (and congestion) in the prices charged and paid to consumers and generators respectively (as in locational marginal pricing, LMP).

Assessing the different possible charging methodologies against the five criteria, the paper rejects completely non-locational ('postage stamp') transmission charging as inconsistent with the efficiency criterion, but considers that the residual element to cover transmission costs should be non-locational, as at present. The paper's assessment of the Investment Cost-Related Pricing (ICRP) method, which is broadly that currently in use in the UK, concludes that the locational signal in TNUoS is in the right direction, but may be too weak, and that it is robust and workable. One criticism of ICRP is that it takes no account of spare capacity in the network in its price signals. This could be addressed through an improved ICRP (IICRP), which forecasts the time before a reinforcement would be required. A method that starts with demand forecasting is Long-Run Incremental Cost (LRIC) charging which calculates when reinforcements will need to be made and then sets the charges on the basis of the annualised cost of the network reinforcements that will be required. This method was developed for and is employed by the distribution network in the UK, but its use in transmission may be problematic because of the uncertainties in the assumptions that have to be made about demand growth and the likely pattern of generation. Another variant on ICRP that is discussed is relating the charges to energy flows (Investment Cost Related Energy Pricing, ICREP) rather than or as well as power. This would send a locational signal concerning actual generation or use of energy rather than only the location of power supply and demand, and, if congestion-based, would tend to benefit low load factor generators, to the extent that they cause (on average) lower congestion on the transmission system.

A completely different approach to transmission charging is nodal energy pricing, which may be system or locational marginal pricing (SMP or LMP), the latter of which was also extensively discussed by Newbery. A version of SMP was used in the Electricity Pool in England and Wales and is used in the NordPool, but the paper does not give it detailed consideration. LMP, however, is discussed in detail, as it was in Newbery's paper. However, this paper's assessment of LMP is less positive overall than Newbery's. It recognises that LMP is the most efficient means of charging for transmission, but considers that FTRs may provide an inadequate hedge against volatility and risk. They are also more complex than the current system and would be likely to require significant changes to industry codes and procedures.

In discussion, the paper assesses the main methods of transmission charging against the three elements of the 'ultimate objective' of trading and transmission arrangements cited above: cost minimisation, subject to achieving renewables targets and energy security. As already noted, with respect to cost minimisation, 'postage stamp' pricing performs least well. All locational methods send efficiency signals of some kind. The paper considers that the theoretical advantages of LMP are offset to some extent by the uncertainties and volatilities in prices to which it may give rise. On the renewables targets, given that a substantial proportion of UK renewables are located in areas remote from demand and with little transmission, it is clear that locational charging would make such renewables more expensive than they would otherwise be. This might delay or prevent them being developed, with consequent implications for the achievement of the renewables targets. On energy security, the presence on the system of large amounts of intermittent renewables would require a large amount of reserve capacity to be used when power was required but renewable generation was low. The paper makes the point that, if this reserve capacity was located in the same area as the renewables, then they could share transmission capacity, because only one of the renewable and reserve capacity would be used at any one time. However, high locational charges might deter the investment in reserve capacity in areas where it could share transmission with renewables. Whether this mattered would depend on the relative costs of the transmission losses from using the reserve capacity in a location remote from demand, and of providing any necessary transmission capacity were the reserve capacity to be located elsewhere. The provision and location of reserve capacity will also be influenced by the nature and level of any capacity payments that may be introduced, following the current consultation on electricity market reform.

Table 2 summarises the various assessments carried out in the paper, in terms of the implied rankings given by the discussion in section 7.8, pp.64-65. LMP performs best on efficiency. ICRP performs best on most of the other criteria, largely because it is the current system and continuing with it therefore implies least change and disruption. There is little to choose between the methodologies on energy security; cost-reflective charging for renewables may deter investment; and there is limited stakeholder support for change of any kind.

Table 2: Ranking implied in Bell et al. paper of different main charging options against various criteria (1=best, 3=worst)

Criteria	**Postage stamp**	**ICRP**	**LMP**
Economic efficiency	**3**	**2**	**1**
Robustness	**1**	**1**	**3**
Workability	**2**	**1**	**3**
Complexity	**2**	**1**	**3**
Stakeholder support	**2**	**1**	**2**
Renewables targets	**1**	**2**	**3**
Energy security	**1**	**1**	**1**

While the paper concludes that some ICRP-type methodology is the “best compromise option” (p.69), it also considers that as currently practised in the UK it is “inadequate” and “should be revised to provide more accurate reflections of the drivers for network investment”, notably to reflect energy flows and the ability of intermittent and reserve capacity to share transmission capacity. Other issues that require attention are listed as consistency of treatment between onshore, offshore and island generation; the ‘security factor’; and the high-voltage DC undersea cables (‘bootstraps’) that are planned to facilitate the connection of offshore renewables.

Peer Review of Baldick, R., Bushnell, J., Hobbs, B. & Wolak, F. 2011 ‘Optimal Charging Arrangements for Energy Transmission: Draft Final Report’

The transmission charging principles put forward in this paper are:

“1. Charges for the usage of the network should reflect the incremental costs imposed by that usage.

2. Charges to recover historic (sunk) capital costs and other fixed costs should distort usage as little as possible.

3. Environmental objectives are most efficiently pursued through mechanisms that directly address those objectives.

4. Objectives for equitable distribution of costs and risks can be addressed while still preserving incentives for efficient use of the network." (p.1)

Section 2 of the paper is a helpful brief discussion of how these principles may be made operational. The rest of the paper focuses largely on methods of charging that address the first two principles.

Section 3 deals with various mechanisms of short-run congestion management. Uniform pricing of electricity effectively assumes no congestion, and any actual congestion has to be managed through a process that can be costly. Zonal pricing adopts uniform pricing within zones (within which congestion has again to be managed), but varies prices according to congestion between zones such that generation within zones that have export constraints is only paid the marginal cost of the most expensive plant within the zone that can operate. Full locational marginal pricing (LMP) applies the same principle of differential payment for generation to individual bus-bars.

In contrast to LMP, which gives incentives to new generators to locate in areas without congestion, the current system in GB of 'constraining-off' generation capacity that is prevented by congestion from generating, provides a signal to the system operator (TSO, National Grid Electricity Transmission (NGET)) to build new transmission capacity. This system appears to have some advantages, having "encouraged new investment in the network, facilitated generator interconnections, reduced transmission uplift costs, while increasing the reliability of the network" (quotation from Joskow 1999, cited in note 9, p.12). Moreover, the locational element in TNUoS encourages new generators to locate closer to the demand for their electricity, reducing the required investment in transmission assets. The paper's concern about this system is that it incentivises investment in transmission that may be excessive and result in a total of generation and transmission that is more costly than that which would result from LMP. With substantial investment proposed in remote renewable generation, and the need for very considerable investment in transmission capacity to connect that generation to demand, the paper's worry is that the existing system could become excessively expensive. Moreover, annual changes in the levels of the locational element of TNUoS may cause existing otherwise economic generators to exit if their TNUoS charges are raised. In addition, the prospect of receiving 'constrained-off' payments may cause generators in export-constrained areas to overbid generation into the system, in order to be paid for having it 'constrained off'. Known as the 'INC and DEC game' (p.16), this is a problem that has been observed in the US. Although the paper gives no evidence that this currently occurs in GB, clearly the incentive for it exists, and the paper surmises that prospective developments in the GB electricity system are likely to increase those incentives.

LMP removes this incentive to overbid into the system in order to receive 'constrained-off' payments. Its operation is simply described in Appendix A.1 (pp.43ff.), where it becomes clear that the cost to generators of being located in a constrained area can be very great (in the example given, the price received for electricity in a constrained area, compared to an uncongested area, was \$20/MWh compared to \$100/MWh (p.46)). Clearly this gives a very strong signal to generators not to locate in a congested area (as intended), but it also means that moving from a non-LMP system to LMP could result in serious losses for existing generators unless they are given substantial compensation, through financial transmission rights (FTRs) or otherwise.

Compensating existing generators for a move to LMP may be one role for FTRs (in pursuit perhaps of the "equitable distribution of costs and risks" sought under objective 4 above). Another role is in the hedging of risks of movements in LMPs, when the FTR may provide "a payment equal to the locational price difference between two points" (p.23). The FTRs could be auctioned by the system operator, backed by the congestion rents[10] which it would receive due to the fact that LMP would result in some generators being paid less than the market-clearing price of electricity (as in the example above).

LMP provides locational signals for new generation investment, but not for transmission. The paper posits two models for transmission investment: 'transmission follows generation', whereby generators locate where they wish, and transmission is then built to relieve any ensuing congestion; and 'generation follows transmission', whereby a 'Co-ordinated Infrastructure Master Plan' (p.26) provides what is perceived to be the optimal level and location of investment in transmission capacity, and LMP then causes generators to locate in those areas with least congestion. The paper perceives the UK Government's recently adopted policy of 'connect and manage' as more like generation leading transmission than the opposite, and likely therefore to lead to inefficiently sited generation that then triggers excessive levels of transmission investment. However, what the paper does not mention is the possibility of existing generators in congested areas holding valuable FTRs lobbying against transmission upgrades to relieve the congestion, because this would reduce the value of the FTRs, and thereby causing insufficient investment in transmission, although the extent to which this could or would happen in a GB context is unclear. In any real world in which transmission was supposed to lead generation, it is most unlikely that the 'master planner' would be wholly immune from such lobbying and might be wholly captured by it.

On the current locational TNUoS charges, the paper considers that they are increasingly inappropriate to the GB electricity system and "unlikely to bear more than the roughest relationship to incremental transmission and congestion costs resulting from a siting decision" (p.30) (contrary to their intention to relate to incremental transmission costs as cited in the Ofgem Call for Evidence above). This provides a further argument for moving towards a system of LMP.

For these reasons the paper recommends the introduction of the locational pricing of energy (preferably LMP); the development of a system of financial transmission rights; adoption of a 'transmission leads investment' approach, in which annual transmission charges to cover costs have a very limited locational element, if any (although there could be relatively minor targeted grid enhancement investments funded by generators); and the application of these transmission charges 100% to load.

The final section of the paper assesses these recommendations against ten policy objectives that go wider than the charging principles cited above, and that are derived from the National Grid license conditions, the Ofgem Project TransmiT Call for Evdience and stakeholder responses to it. The ten objectives are:

"[National Grid]

[10] Defined on p.18 of the paper as "the difference between the total market costs paid by electricity consumers and total revenues received by generation unit owners"

1. Facilitation of competition in the sale, distribution, and purchase of electricity.
2. Cost reflectivity in transmission charges, except for transmission congestion costs which are to be socialized.
[Project TransmiT "Call for Evidence"]
3. Provision of value for money for consumers (interpreted as economic efficiency in construction and operation of the transmission system).
4. Facilitation of a timely move to a low-carbon energy sector.
5. Delivery of safe, secure, and high quality network services.
6. Integration of GB electricity markets with the wider European market.
[Stakeholders]
7. Predictability and stability of transmission charges and minimization of regulatory risks.
8. Technology neutrality.
9. Consistency with predominantly bilateral market structure.
10. Transparency and ease of administration." (p.38)

The paper considers that its recommendations broadly meet these objectives.

Discussion

It can be seen that two of the academic papers (Newbery and Baldick et al.) come out firmly for a move to LMP on the grounds of economic efficiency, while the third (Bell et al.), while recognising the efficiency advantages of LMP, gives more weight to its potential downsides in terms of further market disruption and deterrence of investment at a time of very great change, and need for investment, in the energy system.

This peer review cannot, and is not supposed to, come to a firm adjudication between these different views (which were also apparent at the Ofgem-organised workshop to discuss the academic papers, which is the subject of a separate report). However, it may be worth drawing attention to some of the key issues in the debate on which further clarification would be desirable.

Disruption caused by a move to LMP: any change is likely to cause a certain level of transition and transaction costs, market disruption and investor uncertainty. If these are high, then this argues strongly against such change at this time of great energy market change for other reasons. If it looks as if the change can be managed smoothly, speedily and with the retention of investor confidence, then it may be desirable. Probably further clarification on this issue requires more research, and even then will remain a matter of judgement rather than convincing evidence. It should be recognised that the longer this decision takes, the greater the risk to investor confidence whatever decision is ultimately taken.

Current property rights and the role of FTRs: still on the costs of changing the system, Newbery, especially, recognises that a major issue in any change in the transmission charging regime will be the treatment of existing property rights. At present, it is not clear to what extent current property rights would be affected by, say, a move to LMP, how FTRs could address this issue, or the cost of doing so. This is likely to be a major element of the transition costs of a change to transmission charging, and should be a priority area for further research.

Relation of transmission charging to wider Energy Market Reform (EMR): the Government is currently consulting on various proposals for EMR, some proposals for which (feed-in tariffs, capacity payments) will certainly have implications for transmission charging. It is hard to see how the details of EMR (i.e. the levels of any support that may be adopted) can be fixed until the relevant decisions on transmission charging have been taken. This argues for the transmission charging issue to be decided quite quickly.

Locational flexibility of new generation investment: the whole purpose of LMP is to incentivise efficient operational decisions (ie dispatch) from all generation, encourage efficiency in the location, type and timing of new generation, and promote efficient and timely transmission investment. For this to be effective, new generation must have different locational options. In fact, it is not clear that this is the case for the UK over the next ten years. If the great majority of new investment over this period needs, for low-carbon reasons, to be renewables and, at the end of the period, new nuclear and CCS, the locational flexibility of these sources of electricity seems rather constrained. The first new nuclear sites have already been identified, and they are the sites of old or existing nuclear plant, which are already served by transmission capacity. Sites for CCS are likely to be similarly constrained by the vicinity of carbon storage possibilities and, perhaps, the near availability of the requisite fuels. As for renewables, Baldick et al. write (p.34): "with significant new potential renewable generation sites in the GB, it is likely that the total amount of possible renewable resources greatly exceeds the immediate or even medium-term levels of renewable development". In fact, it is not at all clear that this is the case, for the following reasons. To minimise the cost of meeting the 2020 renewables target, it is desirable to build as much onshore (as opposed to offshore) wind as possible (given that large quantities of both will undoubtedly be required). Despite the theoretical availability of a large onshore resource in GB, planning difficulties with and other constraints on its actual construction mean that much new onshore wind is likely to have to be built in the north of Scotland, and that it is probably not putting it too strongly to say that it is desirable to build as much of it as possible. Under these circumstances, a transmission charging system (like LMP) that makes it more expensive to build onshore wind in these locations will not have the (re-)locational effects desired (because there will not be the other locations to relocate to) but will make the wind generation more expensive. This (and any uncertainty in the transition to a new charging system) will either deter the investment in onshore wind or require higher subsidy from some other source. In short, the benefits of a strictly locational system like LMP are not apparent where the response to the locational system is greatly limited by other factors. It would be worth clarifying, given the low-carbon policy objectives of the UK, just how much of the projected new generation capacity required by 2020 may be characterised as 'footloose' (or locationally flexible) and what the benefits of giving the right incentives to this perhaps rather limited capacity might be compared with the costs of moving to a new system.

Sharing of transmission capacity by low load factor generation: as noted by Bell et al., intermittent renewables and reserve capacity for peak loads can share the same transmission capacity, because by definition they will not be generating at the same time. It is not clear that the current TNUoS charges give the appropriate signals for the location of this capacity. Perhaps an incorporation of an energy element to the charges, as suggested by Bell et al., would do so. This issue certainly deserves further investigation and further explanation, given that it is not yet clear how any energy component would be applied.

Construction of new transmission capacity: it is certain that to meet its policy objectives GB will need significant new transmission capacity, and it is important for the policy targets to be met that this is put in place without delay. In this context the 'transmission leads investment' model of Baldick et al. is attractive. What is important is that the operation of this model is not constrained by the adoption of a system of transmission charging that gives incentives to any powerful actor or group of actors (and the GB power market is fairly concentrated) to make inefficient decisions. It could be argued that, to some extent, the system of 'constraining off' already does create incentives of this kind. It is important that these incentives are removed, and no new incentives of this kind are created, by whatever system of transmission charging is adopted, so that this system does not negatively influence the ability to make efficient decisions, in terms of either operational dispatch or transmission investment.

What this discussion, and many of the arguments in the papers reviewed, seem to suggest is as follows:

1. The decision on any new system of transmission charging should be taken relatively quickly (i.e. in 2011).

2. If the main priority is to meet the 2020 renewables, and wider low-carbon, targets, no decision should be taken that will involve significant market disruption or investor uncertainty at this time.

3. The current locational element in transmission charging should at least be maintained, and the move to LMP investigated on the basis of National Grid's current software and systems.

4. Decisions on new transmission capacity to accommodate onshore renewables in those areas where it is easiest to build them should not wait or depend on the decision on transmission charging.

Peer Review of Baker, P., Mitchell, C. and Woodman, B. 2011 'Project TransmiT: Academic Review of Charging Arrangements'

The report commissioned from the Energy Policy Group at the University of Exeter had a rather different remit from the other reports, and was asked to consider the following questions:

- "Whether transmission charging arrangements should be a relevant vehicle to promote low carbon generation? ;

- How the transmission charging arrangements could be structured to either remove barriers to, or to facilitate the deployment of, low carbon generation? ;

- How such arrangements might fit with the wider context of the Governments' existing and proposed policy for supporting low carbon generation? ; and

- What the implications of doing this might be in both the short and long-run, in terms of the costs seen by customers, security of supply and competition in the generation market? "

These questions place less emphasis on the efficiency priorities for transmission charging and more on the issue of facilitating low-carbon generation than the remit for the other reports, and this report reflects this different emphasis, except that it regards the main current issue relating to low-carbon generation as meeting the UK renewables targets, and responds to the questions in this sense. This paper gives attention than the other papers to the issues of charging unlicensed generators connected to the distribution network for access to the grid, and to connection charges.

The paper argues that certain developments external to the GB charging framework provide support for the argument that the use of system charging arrangements could positively assist in delivering decarbonisation. Such developments include the statutory obligation on the UK to meet the EU-derived renewables target (15% of final demand by 2020 to come from renewable, implying around 30% of power generation), and accompanying EU-mandated obligations to give renewables priority or guaranteed access to the grid system. Against this background, the paper suggests that Ofgem needs to adopt arrangements that support the attainment of government targets, and therefore transmission charging arrangements should arguably be consistent with, or at least not make more difficult, the widespread deployment of renewables. There is an obvious tension here between the principles of economic efficiency applied narrowly to the transmission system, and arrangements for the transmission system that might seem inefficient in themselves, but in the wider context could enable the renewable targets to be met at lower cost.

The paper asserts the point that was raised by Bell et al, but more strongly and again without providing evidence, that the ability of onshore wind in particular to respond to locational signals was very limited. Given its cost advantages over offshore wind, and the very great quantity of wind that will be required to meet the renewables targets, transmission charging should therefore ensure that it enabled the maximum quantity of onshore wind to be connected to the grid, wherever in the UK it was located, because this would still be very likely to be cheaper than replacing it with equivalent offshore capacity. This could be achieved by reducing transmission charges for onshore wind. However, the paper argues against 'flat' transmission charging for all generation, because this would fail to give incentives for efficient location to those forms of generation that could respond to it.

The paper also picks up the point made by Bell et al that intermittent generation like wind will not always need transmission capacity at its full rated power, and can therefore share such capacity with reserve capacity that would be used when the wind was not blowing. Transmission charging could reflect this ability to 'share' capacity, which does not exist for plant designed to operate all the time at close to its rated power. However, the paper sees little merit in another suggestion made by Bell et al, that transmissions should be based, partially at least, on energy flows, rather than rated power, on the grounds that it is rated power that drives required transmission capacity, and charging based on energy flows would benefit low load factor peaking plant which imposed no less a requirement for transmission investment than base load plant.

Another important point that again arose in the other papers was the need to ensure that any new transmission charging arrangements were consistent with, or evolved towards, the requirements of European integration over the next few years. The paper observed that modifications or improvements in the context of the current regulatory and market background may have a "relatively limited shelf life due to the advance of European electricity market integration." (p.5), and suggested that a move towards the principles of nodal or zonal pricing may come to be seen as "inevitable" due to such integration (p.17)

On the issue as to whether transmission should lead or follow generation, the paper argues that despite the adopted approach of 'connect and manage' seeming to imply transmission following generation, in fact there were strong arguments for Ofgem to incentivise National Grid and other TOs to take a strategic view of transmission, especially where it was very likely to be required for renewables and where the timely connection of renewables would be important for the achievement of the renewables targets.

On two additional issues addressed by this paper in more detail than the other academic papers, this paper considers that: charges on generators connected to the distribution network should be levied in the first instance on the Distribution Network Operators (DNOs) according the flow across the transmission-distribution boundary, reflecting the use by the distribution system of the wider transmission network; and that securitisation charges on project developers against the risk of them not utilising transmission capacity that had been provided for them currently bear disproportionately on smaller renewables developers, and should be shared more equally between generators (new and current, TOs and customers).

DISCUSSION AND CONCLUSIONS FROM CONSIDERATION OF THIS PAPER IN THE CONTEXT OF THOSE DISCUSSED EARLIER

It is possible to argue that transmission charging arrangements should only seek to incentivise the efficient development and operation of the transmission system, and that if it is desired to encourage particular forms of generation, for example in pursuit of policy objectives of decarbonisation or energy security, different and specific policy instruments should be used.

However, that is not the approach taken by this paper in response to its motivating questions, set out above, which explicitly ask whether and how transmission charging arrangements might promote or facilitate the deployment of low-carbon generation. By following the clear prioritisation adopted by this paper between the various objectives relating to transmission, and other related, charging arrangements, it is possible to arrive at a fairly firm set of conclusions on the basis of the arguments presented. Clearly a different set of priorities would lead to different conclusions, and the most important of these are indicated in the discussion that follows.

Priority 1: the UK should do what is necessary to meet its obligations of decarbonisation under UK law, and deployment of renewables and integration into EU electricity markets that is required under EU law.

This argues for the following approaches to charging:

- Transmission and connection charges for onshore wind (and perhaps other onshore renewables, though this is not mentioned in the paper) should be set to ensure that as much onshore wind as possible is connected, to reduce the need for offshore wind to meet the renewables targets. While any discounted transmission and connection charges of course represent a subsidy to onshore wind, there is a need for further work to determine how much subsidy would still be likely to be less (and should not be provided unless it is so) than the subsidy that would otherwise go to offshore wind (through the Renewables Obligation or some other mechanism), taking account also of any extra transmission losses that any increase in remote onshore wind would incur.

- Given that a high proportion of UK wind will be in Scotland, especially northern Scotland, substantial further transmission infrastructure between English demand centres and Scotland should be provided in advance of generation capacity to ensure that this capacity can be connected to the grid as soon as it is constructed, both to maximise the possible use of the wind resource and to reduce the payments for 'constraining off'. To some extent this is already happening (Beauly-Denny, Cheviot reinforcement), and much more is planned (in particular the two offshore HVDC 'bootstraps' off the west and east coasts). More may be required, and it is important that whether this is so is clarified and further work put in hand without delay if necessary. The importance of this infrastructure being provided in a timely manner cannot be overemphasised if wind capacity is to be constructed at the required rate for the targets to be met.

- The transmission infrastructure will need to be sized to the rated wind capacity, but the low load factor of wind means that it will be underused much of the time. This argues for giving incentives, through reduced transmission or connection charges or both, for the sharing of infrastructure capacity in a geographic location between intermittent generators and thermal peaking capacity, because the latter will only be required when wind power is not available. However, power from this peaking plant will be subject to higher than average transmission losses if it is far from the demand it is serving, and the level of subsidy should not be so great as to completely overwhelm such other considerations of cost-effective location.

- It is not clear that other low-carbon capacity (for example, nuclear or carbon capture and storage [CCS]) needs the special locational treatment accorded to onshore wind (not least because it does not count towards the renewables targets), so that the requisite public support for these technologies should continue to be provided exclusively by other means (for example, the carbon price, or subsidy for demonstration projects).

- Changes to electricity market arrangements, including those related to transmission charging, that delay or deter investment in renewable or other low-carbon technologies should be strictly avoided. It is important to clarify soon the costs and timescales that would be involved in moving towards a different locational charging mechanism like LMP, so that a decision on the nature of future transmission charging arrangements can be taken quickly.

- EU integration of electricity markets is likely to require a locational element to electricity pricing, rather than locational transmission charging to give long-run investment signals. As is made clear in all the papers, there are also powerful arguments of cost-effectiveness against moving to an all flat-rate transmission charging arrangement. It is currently not clear whether the current TNUoS charging arrangements (perhaps appropriately discounted for onshore wind and peaking reserve as mentioned above) would be consistent with EU integration, or whether this would be better served by some system of zonal pricing or LMP (with special arrangements for onshore wind). This situation should be clarified as soon as possible.

- While there are arguments that DNOs and suppliers should be encouraged to connect renewable or low-carbon capacity to the distribution grid by relevant charges being related to the net energy flows across the transmission-distribution interface, this issue is somewhat removed from the main focus of Project TransmiT, and seems to require further analysis in the context of the present arrangements already requiring these charges to be cost-reflective.

Priority 2: the UK electricity system should continue to provide power when and where it is needed at least at historical levels of reliability, while giving maximum opportunities for flexible power management through demand-side as well as supply-side measures.

The maintenance of power system reliability and resilience requires investment, and 100% reliability would be very expensive, if not impossible, to achieve. In the past the desired level of reliability has been provided through a mix of generating fuels (some of them indigenous, like coal), and base load and more flexible plant, with a 20-25% capacity margin to ensure that peak demands can be met. In the future a greater proportion of generating fuels will be imported, and more low-carbon generation that is relatively inflexible and best suited for base load, and more variable and relatively low load factor renewables, will be on the system. It will be desirable (as well as mandated in EU law) to give indigenous renewables priority grid access (for reasons of both energy security and meeting the renewables targets, which are expressed in terms of the proportion of renewable energy delivered). Power management will be through some combination, as yet undetermined, of peaking reserve (with the capacity margin likely to increase), demand management (including through electric vehicles and remote control of household appliances) and storage (perhaps using new technologies still to be developed on a large scale). It is important that further work clarifies to a greater extent the relative role to be played by these power management methods, and the costs involved, for different power supply combinations.

Priority 3: the two above priorities of decarbonisation and greatly increased deployment of renewables, and energy security, should be met as cost effectively as possible.

It has already been noted that this rules out a wholly ‘flat’ system of transmission charging. It should also be ensured that the subsidy (from reduced transmission and connection charges) to onshore wind and peaking reserve is respectively below the extra costs of offshore wind and increased transmission losses.

A strong case has been made for the efficiency advantages of LMP over other locational charging/pricing methods, provided that competition conditions in the UK market enable the theoretical advantages of LMP to be realised, that the costs of moving to such a system are reasonable, and that there is no disincentive to the required renewables investment during the transition. Further clarification is desirable as to the extent to which these conditions hold.

Locational charges should reflect as far as possible the costs of energy supply, congestion and transmission, giving incentives for the efficient short-run management of the system and the efficient location of new plant within the over-riding policy parameters adopted by government. Locational charging (or electricity pricing) should not seek to cover the whole costs of transmission provision, the residual element of which should be met, as at present, by a non-locational charge (although the reports suggest that this should be levied 100% on load, rather than the current 73%). If special charging arrangements were adopted for onshore wind and peaking capacity that shares its transmission capacity, use of system charges could once again be more clearly related to the actual costs of providing access to transmission infrastructure. It should also be recognised that the 'connect and manage' rule that has been recently adopted, coupled with the current shallow charging regime, leads to inefficiencies in the management of congestion in the transmission system, because generators may connect to the system without taking account of, or paying, any costs of congestion or transmission reinforcement which their connection may cause. It is desirable that the costs of this rule are kept under review and regularly compared with the benefits of timely access to the grid for new investment that the rule provides.

SOME ERRORS IN AND DESIRABLE AMENDMENTS TO THE PAPERS

Newbery, D. 2011 'High level principles for guiding GB transmission charging and some of the practical problems to transition to an enduring regime'

pp.28-29: ICRP is referred to as both 'Investment' and 'Incremental' Cost Related Pricing. Surely this usage should be consistent with one or the other?

Bell, K., Green, R., Kockar, I., Ault, G. & McDonald, J. 2011 'Academic review of transmission charging arrangements'

p.10, main paragraph under 2., line 3: it should be '… 15% of the UK's final energy demand …' not 'primary energy'

p.20, under 5.2.1, line 4: text should read 'Others levy some part on generation and the rest on demand;' not '… the rest on generation;'

p.28, 6.2: in the heading the method discussed here is called 'incremental cost-reflective pricing' but below and elsewhere it is called 'investment cost-reflective pricing'. If these are in fact the same, as seems to be the case, there should surely be consistency with the nomenclature; if not, the difference should be explained.

p.37, line 6: delete second 'time to'

p.38, 6.4.1, second paragraph: ICREP is said to represent Investment Cost Related Energy Pricing, but ICRP is defined as Investment Cost-Reflective Pricing. Is it intended that the 'R' in the acronyms stands for different words? Should they not be the same?

p.53, end of line 2: word missed out. Insert 'sensitive'?

Baldick, R., Bushnell, J., Hobbs, B. & Wolak, F. 2011 'Optimal Charging Arrangements for Energy Transmission: Draft Final Report'

p.1, 9 lines from bottom: should read '… would purchase more energy from the lower-priced producer and less from the higher priced producer …' (changed word highlighted)

p.4, three lines from bottom: should be '2010' not '2011'

p.25, end of first paragraph of 4.4: should be '… out in …' rather than '… in out …'

p.26, line 7 of point 1.: delete first 'more'

Baker, P., Mitchell, C. and Woodman, B. 2011 'Project TransmiT: Academic Review of Charging Arrangements'

p.8, note 3: insert 'by' after 'introduced'

p.9, line 13: 'technologies' not 'technology'

p.10, line 12 from bottom: insert 'be' after 'need to' p.12, line 10: ‘rationale’ not ‘rational’

p.17, line 3: substitute ‘seem to be’ instead of ‘be seen to’

p.18, line 1: ‘were’ not ‘where’; line 3: ‘than’ not ‘that’; line 11: substitute ‘switch’ for ‘increase’

p.19, bottom line: ‘bear’ not ‘bare’

p.20, line 7: meaning of ‘issues such as risk the equitable treatment’ is not clear; line 13: insert ‘to’ after ‘TOs’

p.21, second paragraph: a strong statement is made here in the sentence on ‘the asymmetrical nature of costs’ but no analysis, or any references, are given here to back this up. Some evidence or argument is desirable.

p.22, line 9 from bottom: substitute ‘Where’ for ‘While’

p.23, line 17: ‘through’ not ‘though’; line 23: ‘adoption’ not ‘adopting’; line 3 from bottom ‘complement’ not ‘compliment’

p.24, line 18: ‘complement’ not ‘compliment’

p.27, line 8: ‘than’ not ‘that’; delete ‘Nodal or zonal pricing’ at end of 7.3.3

p.28, line 12: ‘rationale’ not ‘rational’; last sentence of 7.6.1 makes strong assertion about the relative costs of late and early transmission – some evidence of this would be desirable