TRANSMISSION ACCESS STANDING GROUP

Straw Man Proposal

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Introduction

This proposal starts by identifying the requirements of users of the network and the knowledge base of parties involved with the transmission network. It then looks at the current arrangements and identifies defects in meeting those needs. From that base it proposes a fundamental change to the existing codes as set out in greater detail below.

It is central to this straw man that bandaid solutions, changing details of the existing regulations in an effort to patch over problems, are not the way forward. A revolutionary rather than evolutionary approach is needed as the defects identified in this paper are fundamental.

Requirements of Users

The two users of the network are generation and load. Generation plant wants to be able to offer electricity to the market on an unconstrained basis while load wants the flexibility to buy from any generator irrespective of their location, dependent only on pricing. The role of the network is to:

a) facilitate that to the greatest extent feasible **-**
b) at as low a net cost as reasonably possible which is passed back to system users.

To the extent that the network does not meet this fundamental need, market inefficiencies will result which will **always** mean higher electricity prices for the consumer.

In meeting these needs, the network codes need to give consideration to the way in which different approaches might impact users. Different generation types have different sensitivities to the absolute price and volatility of price of network costs as well as availability of the network at any time. This sensitivity is driven by two quite separate factors – economics and technology:

Economics: Renewable generation technologies which use zero cost fuel sources such as wind power and hydro tend to have high initial capital costs. The initial investment decision to proceed with building these plants is very dependent on certainty of future net revenues. Power sales are typically contracted long term and the plants must have confidence that they can generate at all times for known operating costs, including network use of system costs, over the forecast life of the plant. A legislative environment where this is not the case will result in this type of plant being unable to be built or being built in lower quantities.

Conventional plant, by contrast, is typified by much lower capital costs but much higher operating costs, principal among which is fuel. This plant tends to lock in long term power price contracts less frequently, focussing more on spark spread. Changes in operating costs which impact the market generally can be absorbed as power prices rise across the market in response. They are therefore able to better tolerate an environment where network use of system costs can vary. Lack of network for periods also has a much lower financial impact on conventional power generators as their loss from not generating is the power price less their fuel and operating costs, compared to the power price less minimal operating costs for renewable generation (leaving aside the value of ROCs). Note that these comments are subject to the technology comments below.

Technology: Where the network cannot be delivered to meet economic needs of the users, this problem can be addressed contractually through constraint payments. There are real physical requirements for the system however, driven by technology considerations. A regulatory environment in which the network may be physically unavailable at relatively short notice will be a serious problem for base load plant such as nuclear which cannot easily and quickly respond to changes in its ability to export power. This ability will change in line with known technology banding, all the way through to pumped storage hydro with almost instantaneous response capability. Any code changes have to bear in mind this need of different plant to have greater or lesser certainty of network availability. This is not an equal world and a structure which does not recognise this is inherently flawed.

The network does not need to be capable of delivering all power at all times from all generation. It must have regard to levels of plant margin in the system. The level of plant margin – currently around 20% - will rise in the coming years as intermittent generation becomes more widespread.

When determining a net cost, the System Operator must balance the cost of new investment against the cost of any constraints. The latter is dependent on the constraint cost regime as well as forecast utilisation of lines.

Complexity of arrangements for transmission access inevitably creates barriers to entry for smaller generators and discriminates against smaller energy suppliers, making the overall market less competitive and thereby increasing costs to consumers. Complex access arrangements also create a burden of administrative cost within users, the System Operator, the Transmission Owners and the industry regulator. This would potentially have knock-on effects in making the Price Control Review process more complex as well. It impedes finance and investment decisions also. Users will prefer a simple solution over a complex solution

Knowledge Base

Generators are only in possession of knowledge about their own plant in terms of output levels, contract arrangements etc. They do not and should not know the contract arrangements of other plant, potential outages or levels of demand on the system at any time. Similarly supply companies lack information about competitor load flows, contractual arrangements etc. Neither generators nor supply companies have sufficient information to understand or make judgements about the availability of the network to take the power necessary to meet their respective contracts at any point in time.

Power requirements are temporal - they fluctuate minute to minute. Those fluctuations are controlled by the System Operator in conjunction with the Transmission Owners through the mechanism of the BSC. Furthermore capacities on lines are not constant – they vary according to a range of factors including ambient temperature, fault conditions, outages for maintenance etc.

Even with a static system in which generation and load do not change, average system utilisation may be dynamic. Changes may arise over time from changes in commercial contracts where suppliers change purchase arrangements between generators, resulting in different power flows around the system. By way of extreme example, if the market moves from one where say 20% of the country's generation plant lies in Scotland and is normally not used, to one where the suppliers change contracts and take power from Scotland while leaving southern England generators as reserve, the power flows round the country will change without any fundamental change in either the locations or quantum of generation capacity or load.

CUSC, BSC and SQSS

In different ways each of the CUSC, BSC and SQSS codes impact the operation of the grid network and its interaction with users. The UK is unusual in having a market driven by bilateral contracts rather than a despatch driven system. Operation of the UK market on a bilateral contract basis has seemingly proved successful for consumers and this paper therefore takes as a fundamental assumption that this concept remains, with no movement back towards any kind of pool mechanism.

The practical operation of the network and balancing of generation and demand from moment to moment requires the Balancing and Settlement Code structures. It is assumed that the fundamental concepts inherent in the BSC are therefore correct and have proven themselves in successful operation. As far as possible any changes to address defects in the CUSC, through failure to meet the needs of users, should not impact the BSC except potentially in the area of bid/offer prices. This is therefore another fundamental assumption in this paper.

SQSS is about an intentional overbuild of the network to provide, as the name indicates, security of supply. New generation on the system, by itself, cannot adversely impact security of supply as if it doesn't generate, the existing generation remains capable of meeting all load requirements as previously unless and until it is taken out of service and ceases to be available. This does not imply that the network can handle the power flows with the new generation in place and generating but that is not the same issue and an important difference. It is noted that the SQSS is under review at this time but this paper does not concern itself with meeting the SQSS in its current form. It is focussed solely on changes to the CUSC to better meet the needs of users as they have been identified above.

CUSC Defects

Central to the CUSC is the concept of TEC. This is a capacity product giving everlasting rights to a generator to export up to the full amount of TEC at any time into the MITS. The network is built to accommodate maximum TEC export from each plant within transmission boundaries and then allowances made, across transmission boundaries, for net power from that area (installed generation capacity less winter peak load), scaled down for plant margin on thermal and a 60% factor on wind power, to be exported to or imported from the adjacent area. Economic considerations could in theory determine that more network capacity should be built than this approach would indicate but such considerations cannot provide for less network capacity construction than this determines, unless by specific derogation.

Defect 1: This approach does not take account of whether generating plant is operated continuously (by being a peaker plant, for example or by being intermittent generation such as wind power). A consequence of this is that for most of the year, all transmission lines (other than known pinch points such as the Cheviot Boundary) run at much less than theoretical capacity. There has been an evolution of derivative TEC products such as STTEC and LDTEC within planning years in an effort to make such capacity available to the market but reflecting the economics of generating plant as well as the comparatively local nature of these, such short term access products have proven to be of little interest to the market to date and have not been a success. The current structure of the CUSC gives no scope to better utilise transmission assets. The resulting inefficiencies create higher costs within the power market but in a stable world, these costs are relatively marginal (transmission costs are only circa 3% of overall power costs).

Defect 2: The everlasting nature of TEC creates a barrier to entry to new plant (mostly new renewable generation), arguably in breach of NGET's transmission licence which provides for all users to be treated equally and without (undue) discrimination. In conjunction with the impact of the SQSS, new generating facilities will have to wait for major upgrades to be carried out before they can connect. This is adversely impacting supplier choice and market economics. For example, if a new consented 100MW wind plant wishes to build and connect in Scotland today at an effective brown power price (contracted term) of 3p/kWh (net of ROC's) but it cannot connect because of a TEC held by a conventional power plant generating at 3.5p/kWh, the market is having to pay the additional cost of the more expensive generator merely because they hold their everlasting TEC right in preference to the new and cheaper wind generator. This would not be a problem where the new wind generator is more expensive because presumably market forces would determine that suppliers would not buy power from them but would choose to stay with the conventional generator. The choice does not exist however with the current CUSC structure.

Defect 2 has a further consequence. It makes it extremely difficult for developers of new generating plant to bring the time lines for planning approvals into line with the time lines for grid connection when multiple deep upgrades are factored in. This is causing projects to fall away and increasing the risk of stranded assets.

It should be noted that Defect 2 is only apparent because the SO cannot respond instantly to new generation. If system planning and installation of new network capacity could be done very quickly and planning approvals similarly, new lines could be built in immediate response to changes in generation and this defect would no longer be apparent. The financial burden to the power market caused by the inefficiencies created by this defect are difficult to determine but we would suggest are a considerable order of magnitude larger than the financial costs of the first defect. Defect 1 is an ongoing defect but one whose quantum, although potentially significant in absolute terms, may be small in the context of prices in the market.

Because most new generation planned in the UK is wind power, Defect 2 is also adversely impacting Government introduced measures to address climate change. This is not in breach of NGET's transmission licence as such but contravenes the intention of Ofgem's duties towards the environment.

There is an implicit Defect 3 here but it is not drawn out as a separate and distinct item – that of TEC itself when used as a determinant of network capacity availability. As illustrated throughout this paper, maximum potential output capacity of plant connected to MITS is *not* in any way an accurate indication of the required transmission network to deal with real-time power flows.

Straw Man

This straw man is divided into three parts:

- i) connection and network management;
- ii) costs
- iii) charging

Connection and Network Management

Going back to the fundamental requirement of users, it is proposed that the CUSC be changed to allow all consented generating plant other than distributed generation, regardless of type, to connect to the grid. It would be the responsibility of the SO to consent and build shallow connections, providing each new generator with CEC. Management of the system then falls to NGET in conjunction with the TO's – this is a full "connect and manage" approach.

As soon as a plant is connected, it will be allowed to generate but may be subject to constraint. As currently provided under the BSC, it will give NGET notification of intended generation levels in advance each day. It will be classified into a group according to the combination of economic and technology factors applicable to its generation type – for example as base load, mid-merit or peaker. These or alternative categories may be additionally weighted by regard to carbon emission levels. Wind power generation, in recognition of:

- i) the low carbon nature of its generation and contribution to Government emissions targets;
- ii) high capital cost and need for certainty of revenues;
- iii) intermittent nature of its generation

would be considered a base load provider, as would nuclear plant.

The SO would not constrain off such base load plant unless there was no alternative. It would constrain off plant broadly in merit order where physical constraints on the system at any time required it, except that it would need to retain some flexibility to access peaker plant on the network to the extent necessary to manage short term load changes (e.g. half-time in the FA Cup Final). Where constraints mean that suppliers are not able to buy power from their chosen generator, power will be supplied using the BSC provisions as modified below.

This approach to network management would allow the closest possible structure to the perfect market. Users would contract between themselves for the cheapest power available in the market, lowering the cost of power to consumers, leaving aside the cost of the transmission network which is addressed below.

New generation on the system in areas already having low cost conventional generation will result in physical constraints in the short to medium term, pending construction of new transmission lines. This is a transient issue however and not a long term difficulty. The presence of the new generation in advance of the upgrades will provide the ultimate signal of need to the SO and ensure that stranded assets are simply not possible. Construction of new lines only in response to such demonstrated demand will also reduce the present planning burden on the TO's and SO, who are currently designing for a highly uncertain possible network expansion. There will be a real and demonstrable saving in associated market overheads.

Intentionally leaving aside considerations driven by the SQSS, this approach would optimise use of the network minute to minute and should reduce the level of possible overbuild. It will resolve both identified defects.

Costs

Costs from operating the network in this way divide into two interrelated parts:

i) costs of the infrastructure;
ii) constraint costs

These two are interrelated because leaving aside short term constraints created by the timing difference between generation being brought on line and additional infrastructure being built to satisfy identified needs, long term NGET as SO will be able to weigh the economics of paying long term constraint costs against the costs of building the alternative infrastructure. By way of example, if a 30MW island wind plant connects to MITS and the infrastructure would require a £100 million upgrade to take the full power then paying long term constraint payments would be a better economic option. If however, five years later, a 200MW conventional plant was to connect in the same area then the upgrade would be justified and constraint payments would only be made until such time as the upgrade could be built.

In a similar way, where the SO has reason to believe that significant other generating plant might connect in the reasonably near term (e.g. the high volumes of wind generation in certain parts of Scotland), it may be a commercially reasonable position to pay constraints until it becomes clear what level of upgrade is truly needed. This would need to be a case by case evaluation done in conjunction with Ofgem.

This straw man conceives a fundamental change to the approach to constraint costs when it comes to payments for generation to reduce. The current BSC structure is a bidding approach but when generation is sitting on a constrained line with a base load provider such as a wind plant, it will be in a monopoly position and would bid up to the price of the wind power, including ROCs, which would be unreasonable. For this reason it is proposed that NGET, in conjunction with Ofgem, should provide a schedule of compensation payments per MWh by generator type to compensate for constraints. Broadly these would be the avoided cost for the generator through not generating (i.e. primarily fuel cost) **and be payable by the generator.**

For technology types where generation cannot easily be reduced (e.g. coal plant), this may also need to reflect the amount of notice given to constrain back, so notice of less than half an hour may be considerably more expensive for certain technologies than notice of say 12 hours. This concept may need to be further refined to take account of operational considerations in plant (e.g. possible unexpected plant damage from taking it off line) so may need to be more plant specific than described. However the underlying concept is to remove the potential to “game” the rules and produce excessive profit from curtailment.

We give an example to illustrate how we propose this should work:

Example 1:

A supplier in the south of England has purchased all electricity from a 50MW conventional power plant in Scotland. In the same area, a new 50MW wind plant connects and on a given day is generating at full capacity. Both plants have sold all their capacity to suppliers.

The amount of generation in the area is more than the system can take. The SO constrains back the conventional power plant by 20MW for one hour. The plant has an agreed constraint cost of £24/MWh representing the avoided fuel cost.

The conventional generator wanted to generate to meet the needs of a supplier to whom he had contracted to sell power at £45/MWh. That supplier is the registrant of the meter at the power plant. The supplier's account with Elexon for the two half hour settlement periods shows 20MW less power than it otherwise would have, creating an account imbalance.

Cost to source alternative power is taken from the pricing stack in the BSC. In this example we shall assume it is £42/MWh. NGET buys the power from that party, paying £840 for the 20MW for the hour. It receives a payment from the constrained generator of £480 (20 x £24) – payment mechanism to be built into the CUSC. The net constraint cost for NGET is therefore £360 or £18/MWh, essentially being the marginal cost of a second plant's overheads for the period (i.e. overhead allocation including capital cost amortisation).

The generator still receives his £45/MWh under his contract with the supplier. After paying NGET £24/MWh, he is left with the same net £21/MWh as he would have had, if he had been able to generate. The supplier is not impacted by the transaction at all.

Example 2:

As for example 1 but both plants are wind plants and both are generating at maximum capacity. It is assumed that some rationale has been agreed for constraining one plant in preference to the other.

There is no fuel cost here and thus there is no constraint payment made by that generator to NGET. There is thus a full £840 net cost of the constraint. There is also a further cost however which is to compensate the supplier for not receiving the benefit of the ROC, even though they had paid to buy it. This would require NGET and Ofgem to agree market values for ROC's and pay additional compensation to the supplier in an equal amount. We will assume the ROC value to be £40/MWh so NGET will pay an additional £800 to the supply company through the Elexon settlement account. This takes the total cost for wind taken off the system to £1640 for the 20MW or £82/MWh.

In this instance the generator is held neutral, doesn't generate, doesn't save anything but receives the same income as if he had not been constrained. The supply company has to pay the ROV buyout price of £30/MWh indexed and loses the benefit of the recycle payment which he had priced into his contract with the generator and paid for, but is compensated by the £40/MWh so should be neutral.

In a more ideal world, constraint costs would be plant specific and be agreed between the plant and NGET annually, reflecting unique characteristics of each generating station. It should be possible to establish a formulaic approach to this which would reduce administration overhead to an acceptable level.

Charging

Costs will be the total of capital cost amortisation and constraint costs. With the system operating as described, significantly more generation near term will be able to connect and fund these costs.

The straw man proposes that costs move from a capacity charge to a utilisation charge per MWh of power put into the system. Reflecting the wish to give regional signals to take into account transmission losses, regional weighting of charges would be retained so a generator in the north of Scotland would be paying more to utilise the network than a generator in the south. The system could be further refined by time of day charging although on a cautionary note, efforts to make any scheme more cost reflective run a risk of adding administrative burden without obvious benefits for users.

The concept of TEC is dispensed with as everyone has a right to generate whenever they are contractually able to do so, albeit they may be subject to constraint but will be held financially harmless. The costs of constraints are socialised.

Parties such as peaking plant will pay substantially less than at present. Intermittent generation will also pay less, reflecting its more limited use of the network.

One further option worthy of discussion would be a capacity charge for the local connection assets unique to a user coupled with the capacity charge for the system.

Conclusion

The concept of a capacity product in the form of TEC and parties having enduring rights to use the transmission network in agreed amounts is at the heart of the problem.

The System Operator is the only party having access to all information, sufficient to know minute to minute utilisation of the system and be able to use it to the maximum capability. This is necessary in order to determine where and when upgrades are required.

The most economic position for the power markets is to give buyers of power full and unrestricted access to all generators who are able to build plant and sell power. As little as a 3% saving in overall power costs would offset all the present costs of the transmission network.

The straw man proposals:

i) achieve this most economic position;
ii) address concerns about timing mismatches between project planning consents and transmission upgrade planning consents;
iii) enable much faster penetration of renewables into the market, reducing carbon emissions sooner and furthering Ofgem’s environmental responsibilities.

The changes to the constraint mechanism give an arrangement which would be fair and reasonable to users of the network with limited or no potential to game the system.

The revisions to the charging methodology revise the way in which costs are bourn by industry parties, providing a fairer allocation of costs to parties using the system.

This paper is put forward as a discussion document to stimulate thinking on the subject.