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14th February 2012

Dear Anthony,

Project Transmit, electricity transmission charging: assessment of options for change

Drax Power Limited ("Drax") is the operating subsidiary of Drax Group plc and the owner and operator of Drax Power Station in North Yorkshire. Drax also owns an electricity supply business, Haven Power Limited ("Haven"), which supplies electricity to a range of business customers and provides an alternative route to market for some of Drax's power output. As both a generator and supplier of electricity, we believe we are well placed to provide comments on Ofgem's initial position and assessment of the potential options for change.

As suggested in the consultation document, the results of the analysis indicates that all three models are consistent with meeting the Government's 2020 renewable targets and each poses no material implication to security of supply. Drax agrees with this statement and believes that the main focus should be on the potential costs and benefits of each model.

It is clear that the Socialised model does not represent good value for money to end consumers. Drax believes that certain elements of the model could have merit, such as the commoditised charge, which would deliver a higher degree of cost reflectivity. However, Redpoint's modelling clearly indicates that the increase in costs associated with the Socialised approach would far outweigh the identified benefits. As a consequence, we agree that this model should not be pursued further.

Drax supports further work on both the Status Quo and Improved ICRP models. It is evident that a change to the transmission charging methodology will be required in time. The "bootstrap" projects that aim to increase capacity between Scotland and England will require a solution to the treatment of HVDC links in transmission charging. In addition, the expected breach of European Tariffication Guidelines must also be addressed in a timely and orderly manner. However, whilst a move from the current baseline to the Status Quo model appears a sensible step, the benefits of introducing the Improved ICRP model appear less clear cut.

We note that the Improved ICRP model provides very limited benefit in the early years, with an overall increase in costs to consumers by 2020. A question remains as to whether the identified benefit could be captured in the early years. This is of particular concern given the likelihood for further changes to transmission and charging arrangements in 2014, with the move towards more harmonised European market arrangements.

However, our key concern regarding the Improved ICRP model surrounds the proposed Annual Load Factor (ALF) methodology. Simple modelling of existing plant clearly shows that the proposal to use historic load factors, averaged over a number of years, as a basis for transmission charging will not improve cost reflectivity. Given the increased level of investment in existing plant over the next decade (including site replanting, turbine upgrades, conversion to new fuels, etc.), it is concerning that generators could face future charges that are based on previous operating behaviour.

We support Ofgem's suggestion of further work to refine the Improved ICRP model, particularly work to address the fundamental flaws of the ALF methodology. Ofgem and National Grid should remain engaged with the industry throughout this process in order to continue the exchange of ideas and to preserve a high level of transparency.

With regards to the G:D split, Drax disagrees that a modification is unnecessary at this stage and we encourage Ofgem to reconsider its position. A change to the G:D split, similar to that modelled by Redpoint, would better align GB transmission charges with those of our continental European neighbours. Harmonisation of charging principles is a key component of the single market, ensuring competition operates on a level playing field across interconnected markets.

National Grid identified the need for a modification to the G:D split in order to remain compliant with European Tariffication Guidelines. This is not a trivial change and will impact all GB market participants, particularly retail businesses with a high proportion of fixed long-term supply contracts. A modification to the G:D split must be signalled well in advance of the change being implemented. As such, there should be at least two full charging years notice to ensure suppliers are able to put into place new commercial arrangements that take account of the change in cost base.

Finally, Drax continues to have concerns over the timing of Project Transmit. There has been little consideration surrounding the potential for further modification to the charging regime that may result from the delivery of more harmonised European market arrangements in 2014. It is not a new comment from industry that regulatory certainty is a key component in the delivery of new investment, although it is an important point worth reiterating.

Further consideration of the views outlined above can be found in Annex 1 to this letter. A response to the specific questions raised by the consultation document can be found in Annex 2.

If you would like to discuss any of the views expressed in this response, please feel free to contact me.

Yours sincerely,

By email

Stuart Cotten
Market Development Manager
Regulation and Policy

Annex 1: Further consideration of the key issues

Socialised approach

The consultation document states that Ofgem wish to rule out the Socialised charging option and focus on the Status Quo and Improved ICRP options. Whilst the model appears to deliver a benefit in terms of the increased delivery of renewable capacity, it is clear that the associated costs of adopting the approach (such as those that result from increased transmission build and constraint management) would significantly outweigh the benefits.

The key issue is the increase in costs to end consumers. On a Net Present Value (NPV) basis, the Socialised model is expected to reduce generation costs by £453m, whilst simultaneously increasing transmission and constraint costs by around £2.8bn, in the years 2012-20. This asymmetric shift in benefits and costs are unlikely to meet Ofgem's statutory objective to protect the interests of present and future consumers.

In terms of consumer bills, the modelling suggests that an additional £6.9bn will appear on consumer bills to 2020 as a result of the Socialised charge. Whilst the sensitivity analysis examined a variant of the Socialised model that resulted in a lower increase in costs (i.e. the retention of local generator tariffs), Drax agrees that the £4.8bn net cost increase would still be unpalatable for end consumers.

Drax agrees that the Socialised approach would provide an additional benefit in achieving Government's 2020 renewable targets. The increase in renewable deployment would provide a safety net, particularly given the fact that the UK is currently experiencing a recession that may be helping headline emissions figures. However, we also agree that the cost of this safety margin would be disproportionate to the benefit.

Drax believes that there are elements of the Socialised model that may have merit. A commoditised charging approach, i.e. where generators are charged on a £/MWh basis, could provide a more cost reflective revenue recovery methodology. This would ensure that generators pay a proportion of charges that reflects their actual usage of the system (i.e. metered output).

Overall, Drax agrees that the Socialised model does not represent good value for money to end consumers. Redpoint's modelling clearly indicates that the increase in costs would far outweigh the identified benefits. As such, Drax agrees that the Socialised model should be ruled out at this stage.

Status Quo versus Improved ICRP

The approach taken to the HVDC links, in terms of the allocation of costs and their treatment in load flow modelling, appears sensible under both the Status Quo and Improved ICRP models. Given the plans for two bootstrap projects that aim to increase transmission capacity between Scotland and England, and the consequential effect that this investment may have on transmission costs, it is important to clarify how such investment will be reflected in transmission charges going forward.

In addition, the reduction in security factors for island links with no redundancy (under the Improved ICRP model) also appears reasonable. However, it will be important to monitor the effect that this approach has on investment in areas affected by the change. It will be a careful balancing act to ensure that the benefit received as a result of investment at the extremes of the system is in the form of compensation for substandard connections, rather than a subsidy for the inefficient siting of plant.

However, whilst a move from the current baseline to the Status Quo model appears a sensible step, the benefits of introducing the Improved ICRP model appear less clear cut. In particular, we note that the Improved ICRP model provides very limited benefit in the early years, with an overall increase in costs to consumers by 2020. A question remains as to whether the identified benefit could be captured in the early years. This is of particular concern given the likelihood for further changes to transmission and charging arrangements in 2014, with the move towards more harmonised European market arrangements.

Annual Load Factor (ALF) methodology

Drax's key concern regarding the Improved ICRP model surrounds the proposed ALF methodology. Simple modelling of existing plant clearly shows that the proposal to use historic load factors (averaged over a number of years) as a basis for transmission charging will not improve cost reflectivity.

It is expected that there will be an increased level of investment in new and existing plant over the next decade. Investment in existing plant could pose a host of challenges for the ALF methodology, such as how to treat plant that is subject to (but not limited to):

- the replanting of a site (phased or otherwise), where the new technology could be substantially different to the existing technology;

- turbine upgrades, where the generator's change in efficiency results in a shift in the plant's relative merit order position;

- conversion to a new fuel source, where the way in which a generator earns its revenue may change substantially, i.e. the addition of ROC income; or

- a change in TEC, where the change could result in the plant being reclassified, such as from CCGT to OCGT.

In each of these circumstances, it would be concerning if the generator faced future charges that are based on previous operating behaviour. It may take the ALF methodology a number of years to fully reflect the new running regime, meaning that the methodology would not result in charges that are reflective of the costs caused by the generator.

There is also the potential for plant that has had very low load factors over a number of years to suddenly become "in merit" due to a change in market circumstances. If this were the case, we would expect such plant to utilise the system to a greater extent, whilst paying a very small proportion of total transmission costs (based on historic output). This scenario could result in TNUoS charges effectively signalling the uneconomic dispatch of plant.

There are further issues for new plant. In the absence of historic data, the use of a market average or assumed generic load factor (by plant type) could be used. However, there are many variables that will determine the running profile of plant (such as location, cost of fuel, market conditions, etc.). Each of these approaches is likely to result in an inaccurate proportion of charges being applied. There must be greater consideration on how the load factor of new plant (and thereby the application of charges) would be determined.

Ofgem have highlighted that there could be a number of variants to this approach that should be explored prior to a final decision. Drax supports this view and encourages further work to refine or replace the ALF methodology. We also encourage Ofgem and National Grid to remain engaged with the industry throughout this process in order to continue the exchange of ideas and to preserve a high level of transparency.

Intermittent generation and its contribution to the peak security tariff

A further element of the Improved ICRP model to consider is the degree to which intermittent generation contributes towards the peak security tariff. The Improved ICRP model applies a 0% contribution from intermittent generation to the peak security tariff. This seems perverse considering that intermittent generation must utilise the transmission system at least some of the time during peak periods.

Drax is not convinced that the evidence presented to the Technical Working Group demonstrates a causal relationship between load factor and congestion costs. Notably the correlation between these two factors breaks down around 2016, which suggests other factors are at least having some influence on the level of congestion costs.

Moreover, we would expect that the different network companies across in GB would want to ensure that adequate transmission capacity is available to ensure that peak output from intermittent renewable output is used to serve demand. Therefore, it seems illogical for intermittent plant to contribute zero revenue towards the peak security tariff.

Drax encourages further work to determine the running pattern of intermittent plant at peak times to ensure that the costs associated with the provision of peak security related transmission is accurately targeted. Again, we encourage Ofgem and National Grid to remain engaged with the industry throughout this process.

Generation / demand (G:D) split

During the Project Transmit Technical Working Group stage, National Grid highlighted a requirement to adjust the current G:D split if GB is to remain within the parameters set by the current European Tariffication Guidelines. The change would be required prior to a potential breach of the guidelines in the latter half of the decade. We note that a G:D split of 15% and 85% (for generation and demand respectively) has been included in all three of the charging approaches modelled by Redpoint.

A change to the G:D split, similar to that modelled by Redpoint, would better align GB transmission charges with those of our continental European neighbours. Harmonisation of charging principles is a key component of the single market, ensuring competition operates on a level playing field across interconnected markets.

Our understanding of the evidence suggests that, overwhelmingly, the vast majority of transmission costs in continental European markets are levied on demand. The variation in how such costs are recovered in differing markets will almost certainly cause a distortion in cross border trading. On the whole, GB generators are charged a greater proportion of transmission costs relative to continental European generators; therefore, it seems appropriate to consider action to rectify the existing distortion in competition.

By modifying the G:D split, so that the G portion of charges is at or close to zero[1], we would expect cross border trade to be optimised via more closely aligned generator transmission costs. Such trade optimisation would be expected to maximise allocative efficiency within the EU and is fully consistent with the EU Member States' and the EU Commission's desire to implement an internal market in electricity. In fact, the maximisation of allocative efficiency within the EU is the main reason underpinning the creation of a single market.

However, we recognise this is not a trivial change and it will impact all GB market participants, particularly retail businesses with a high proportion of fixed long-term supply contracts. A modification to the G:D split must be signalled well in advance of the change being implemented. As such, there should be at least two full charging years notice to ensure suppliers are able to put into place commercial arrangements that take account of the change in cost base.

Adopting a new G:D split as an outcome of Project Transmit will allow the benefits of the change to be achieved as soon as possible, whilst allowing market participants the time they require to transition to the new arrangements in an orderly fashion. As such, Drax disagrees with Ofgem's current view that a modification to the G:D split is unnecessary at this stage. We note Ofgem's call for National Grid to keep the matter under review, with a view to developing an appropriate modification "when necessary". We consider that this approach is too conservative, particularly given the call from industry for adequate transition timescales. Drax encourages Ofgem to reconsider its position.

[1] Please note zero G charges may still reflect cost differentials in that some generators would have negative TNUoS tariffs and some positive if that was the desired approach. Only the net contribution from generators would equal zero in this case.

Timing

As indicated in previous correspondence, Drax remains concerned over the timing of Project Transmit. There are a number of reasons for these concerns:

1. Given the strong likelihood of European-wide changes being introduced from 2014, it is concerning that a second round of amendments to transmission charges could be required within just a few years. Ofgem must give proportionate weight to this issue when considering its next steps.

2. It must be clear in the CBA that the potential “payback” / benefit that results from change (for National Grid, market participants and consumers) is captured prior to amendments imposed by European work-streams in 2014.

3. There is an unprecedented level of change in progress in the GB electricity market, including the RO Banding Review, DECC’s Electricity Market Reform package, a potential cash-out SCR, the introduction of numerous new European Electricity Network Codes and the introduction of further financial / energy market transparency regulation. Ofgem must be certain of the requirement for, and benefits of, change before further increasing the workload of the industry over the summer of 2012.

4. Industry participants, particularly independent generators, require a stable regulatory regime in order to invest. Transmission charges are a significant cost for generators and changes to the transmission regime require due care and consideration to minimise regulatory risk and protect against unintended consequences.

5. Given the changes being considered under Project Transmit, market participants will almost certainly require transitional arrangements. The potential for windfall losses and gains, and consequential disorderly market entry / exit decisions, will be greater if an unreasonable approach to transition is taken. The arrangements must provide at least two full charging years notice prior to implementing change, in order to allow market participants to reflect the changes in future commercial arrangements. This is a particular problem for suppliers with a high proportion of fixed long-term supply contracts. This was one of the areas where consensus was reached during the Technical Working Group stage.

Annex 2: A response to the specific consultation questions

Chapter 4: Modelling results: impact of options

Question 1: Do respondents consider that we have appropriately identified and where possible quantified the impacts of the Project TransmiT options?

It is unfortunate that the timescales surrounding Project Transmit have been very short considering the relative size of the project. Had there been more time, further sensitivities could have been considered by the Technical Working Group, which may have led to a more robust set of scenarios being modelled by Redpoint. That being said, Drax believes that the Redpoint analysis fulfils the specification set by Ofgem.

Drax continues to have concerns with regards to the Stage 2 analysis. The level of support provided to investors in low carbon technologies is a matter of policy and there is no guarantee that the Government will change their policy on support levels, regardless of the transmission model chosen by Ofgem. As such, the modelling should only take account of the support levels currently in place, with a sensitivity that considers the Government's latest position as detailed in the RO Banding Review. Modifying the level of low carbon technology support, as carried out under the Stage 2 modelling, appears inappropriate for this analysis.

Question 2: Do respondents consider that there are additional impacts which we should take into account in the decision making process and, if so, what are these?

Drax emphasises that if a decision is taken by Ofgem to make any material changes to the transmission charging methodology, market participants must be provided with adequate time to transition to the new arrangements. The potential for windfall losses and gains, and consequential disorderly market entry / exit decisions, will be greater if an unreasonable approach to transition is taken. This was one of the areas where consensus was reached in the Technical Working Group and we continue to support the suggestion that implementation should not take place without a two year notice period (i.e. two full charging years).

Drax believes that some of the potential costs associated with the Improved ICRP methodology may not have been captured in the modelling. In particular, if in transitioning to this charging methodology there was an increase in plant closures / TEC reductions in particular areas of the country, the costs associated with the planned Capacity Mechanism may increase as a consequence (relative to the current arrangements). It is not clear whether this effect has been captured in the modelling exercise.

A further potential consequence of implementing the Improved ICRP methodology may be an incentive for greater quantities of low load factor generation capacity in Scotland (both intermittent and thermal plant). There may be additional costs associated with extending the life of current low efficiency plant that is located behind an export constraint.

Question 3: Do respondents consider that we have appropriately identified the potential interactions of the Project TransmiT options?

Drax believes that Ofgem should give further thought to the potential for change to the generation / demand (G:D) split. Ofgem have concluded that the G:D split should not be altered at this stage, but that National Grid should keep the matter under review and only develop a modification proposal "when necessary". We consider that this approach is too conservative, particularly given the call from industry for adequate transition timescales.

Our understanding of the evidence suggests that, overwhelmingly, the vast majority of transmission costs in continental European markets are levied on demand. The variation in how such costs are recovered in differing markets will almost certainly cause a distortion in cross border trading. On the whole, GB generators are charged a greater proportion of transmission costs relative to continental European generators; therefore, it seems appropriate to consider action to rectify the existing distortion in competition.

By modifying the G:D split, so that the G portion of charges is at or close to zero[2], we would expect cross border trade to be optimised via more closely aligned generator transmission costs. Such trade optimisation would be expected to maximise allocative efficiency within the EU and is fully consistent with the EU Member States' and the EU Commission's desire to implement an internal market in electricity. In fact, the maximisation of allocative efficiency within the EU is the main reason underpinning the creation of a single market.

However, we recognise that for the intended benefits to be realised, and for further market distortion to be avoided, there must be an appropriate period of transition to allow market participants to adapt their commercial arrangements. Drax suggests that a decision to alter the G:D split is made as soon as possible with a notice period of at least two full charging years. This will allow the benefits of the change to be achieved as soon as possible, whilst allowing market participants the time they require to transition to the new arrangements in an orderly fashion.

Question 4: Do respondents consider that we have appropriately identified the likely impacts and consequences of these interactions?

<u>CBA</u>

Drax agrees that the choice between the Status Quo and Improved ICRP models is not clear cut. Whilst the Improved ICRP model has been assessed to result in a small reduction in power sector costs (£120m savings to 2020) compared to the Status Quo approach, customer bills would rise by £0.9bn to 2020. Moreover, this small power sector benefit would be wiped out by 2030, with a resulting £500m increase in power sector costs across the period.

Drax questions the margin for error in these figures. It is quite possible that the results are within the margin for error, as evidenced by the low gas price sensitivity which effectively eradicates the relatively small benefit to 2020 associated with the Improved ICRP methodology. Given the recent introduction of a carbon floor price, it could be reasonably expected that the relative merit order of gas plant may change over the next decade. It is not clear how this has been taken into account by the analysis and it could be beneficial to have a separate sensitivity to demonstrate the effects of carbon policy.

<u>European Policy</u>

Whilst Ofgem state that the Improved ICRP methodology appears more consistent with the direction of European policy, the regulator has accepted that this is not the only approach that could be considered to be more consistent. The truth is that EU policy on transmission charging is very uncertain at this stage, which means that it is difficult at this stage to state whether one particular charging methodology is more consistent with EU policy relative to another.

<u>Two Stage Background</u>

An area that Ofgem will need to consider further with regards to the Improved ICRP model is the use of the Annual Load Factor (ALF) methodology to determine the year round generation tariff. Whilst the use of a two stage background for transmission charging seems reasonable, the use of ALF does not seem justified and has the potential to create a number of perverse and unintended consequences.

We do not believe that historic load factors are cost reflective of present operating behaviour. There is the potential for plant that has had very low load factors over a number of years to suddenly become "in merit" due to a change in market circumstances. If this were the case, we would expect such plant to utilise the system to a greater extent, whilst paying a very small proportion of total transmission costs (based on historic output). This scenario could result in TNUoS charges effectively signalling the uneconomic dispatch of plant.

[2] Please note zero G charges may still reflect cost differentials in that some generators would have negative TNUoS tariffs and some positive if that was the desired approach. Only the net contribution from generators would equal zero in this case.

A further element of the Improved ICRP model to consider is the degree to which intermittent generation contributes towards the peak security tariff. The Improved ICRP model applies a 0% contribution from intermittent generation to the peak security tariff. This seems perverse considering that intermittent generation must utilise the transmission system at least some of the time during peak periods.

Drax is not convinced that the evidence presented to the Technical Working Group demonstrates a causal relationship between load factor and congestion costs. Notably the correlation between these two factors breaks down around 2016, which suggests other factors are at least having some influence on the level of congestion costs.

Moreover, we would expect that the different network companies across in GB would want to ensure that adequate transmission capacity is available to ensure that peak output from intermittent renewable output is used to serve demand. Therefore, it seems illogical for intermittent plant to contribute zero revenue towards the peak security tariff.

Drax believes that further analysis is required to determine the running pattern of intermittent plant at peak times to ensure that the costs associated with the provision of peak security related transmission is accurately targeted.

A further issue to consider is whether intermittent plant behind an export constraint should be charged on actual historic output or deemed historic output (i.e. FPN)? Put another way, should generation charges be based on whether plant intended to run and was subsequently constrained off (i.e. TO investment signals are provided to potentially require an increase in transmission reinforcement) or only when the relevant plant actually ran? If charges are only based on actual historic output then the case for TO investment may be undervalued.

Chapter 5: Wider sustainability assessment

Question 1: Do respondents consider that we have appropriately identified and taken account of the key sustainability issues?

No comment.

Question 2: Do you think there may be long term and strategic benefits associated with the development of HVDC technology, in particular the treatment of converter station costs for links that parallel the AC network, which Project TransmiT modelling has not fully considered because of the timeframe of the modelling (i.e. 2030) and the limited nature of the bootstrap options?

Drax does not believe that any strategic benefits associated with the development of HVDC technology should be fostered by making alterations to the transmission charging arrangements. Such amendments risk creating unjustified benefits for plant located in certain geographic locations at the expense of plant located in the remaining geographic locations. If it is considered necessary to provide support in order to develop this technology, Drax believes that this should be achieved via an explicit support mechanism, rather than through the transmission charging arrangements.

Moreover, the variant analysis, whereby HVDC converter station costs are allocated to the residual element of the ICRP methodology, revealed an increase in costs to end consumer bills equivalent to £0.50 per annum to 2020. In contrast, the modelling results in no material benefit from the change. Therefore, we see no justification for treating HVDC converter station costs in this way.

Question 3: Do you have any supporting evidence for a different treatment of the converter station costs for the planned bootstrap HVDC options?

Drax has no supporting evidence for treating converter station costs differently.