nationalgrid

PRE CONSULTATION

GB ECM-23

Transmission Arrangements for Distributed Generation

15th January 2010

Comments and views are invited to all of the issues raised in this pre consultation document. To ensure that your comments and views are considered, responses should be emailed to ivo.spreeuwenberg@uk.ngrid.com by close of business on the **26th February 2010**.

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1.0 Executive Summary

During the development of the British Electricity Trading and Transmission Arrangements (BETTA), implemented in April 2005, industry parties raised a number of issues with regard to the treatment of distributed generation (DG; also known as embedded generation) within the transmission charging and access arrangements. It was recognised that the current access allocation arrangements may not provide a level playing field between transmission and distribution connected generation, and that the current 'embedded benefit' may not accurately reflect the costs imposed (or saved) by DG on the transmission system.

As an interim measure, Ofgem introduced Standard Licence Condition C13 (SLC C13) into the transmission licence. SLC C13 was intended to recognise the difference in treatment of 132kV connected small generation in Scotland compared to similarly connected generation in England and Wales that had been identified through BETTA. The review was due to conclude by May 2009, however progress was delayed by the focus of all parties on the Transmission Access Review. An amendment to SLC C13 was put in place by Ofgem to extend the small generation discount to 2011 in order to allow for further analysis and development of an enduring solution.

One of the fundamental principles of the current charging regime is that charges should signal to transmission users the impact that these transmission users have on incremental investment costs. At present, unlicensed DG is treated as negative demand in TNUoS charging and therefore both avoids the TNUoS generation tariff and (subject to negotiation between the DG and associated supplier) is paid the TNUoS demand tariff. This would be appropriate in a system where all the charges are purely locational, however in order for transmission companies to recover their allowed revenue an additional flat residual charge is applied to the TNUoS tariffs. Due to the non-locational nature of this residual element, coupled with its relative size, DG gains a net TNUoS benefit over transmission connected generation. Whilst DG does offset local demand, the current embedded benefit is disproportionately higher (circa £13/kW) than any potential savings from deferring transmission investment.

National Grid considers that the impact of DG on the wider transmission network is analogous to directly connected generation. A revision to the arrangements for DG, improving cost-reflectivity by redressing the balance between costs and savings, should therefore lead to more economic and efficient investment decisions by generators and transmission companies alike.

Through the Transmission Arrangements for Distributed Generation (TADG) working group, which was convened by Ofgem after BETTA to investigate issues surrounding DG, two models for addressing the differences identified between distribution and transmission connected generation were conceived. The models are the gross nodal supplier agency model (GNSAM) and the Net DNO agency model, both of which seek to address the issues around charging for DG whilst meeting requirements for cost-reflectivity, access allocation and commercial proportionality in conjunction with 'Grid Access' developments.

Whilst National Grid broadly favours the GNSAM methodology as being more cost-reflective, views are invited on the merits and implications of both approaches. National Grid also welcomes the discussion of alternative models that could address the issues around charging for DG. National Grid intends to convene an industry working group 2 or 3 weeks after the conclusion of this pre consultation to assess and refine the proposed models as well as identify the necessary code changes that would be required to implement them.

This consultation document can be found on the National Grid website at the following link:

http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

2.0 Introduction and Background

During the development of the British Electricity Trading and Transmission Arrangements (BETTA) which were implemented in April 2005, industry parties raised a number of issues with regard to the treatment of distributed generation (DG; also known as embedded generation) within the transmission charging and access arrangements.

Following BETTA go-live Ofgem took forward industry debate through a discussion document and the Transmission Arrangements for Distributed Generation (TADG) working group[1]. The TADG process explored a number of issues with DG access and charging arrangements with a view to developing high level options for an enduring solution. Industry parties brought forward a number of potential models, focused on agency arrangements, which were reviewed against Ofgem's principles for change:

i) Cost-reflectivity,
ii) Efficiency in allocation of transmission access, and
iii) Proportionality.

Industry opinion was very much split as to which model was the most appropriate to take forward and, in the Working Group Report published in July 2007[2], Ofgem noted that it is now the responsibility of the industry to take forward proposals by submitting change modifications to the industry codes or other documents.

In an accompanying letter published alongside the report[3], Ofgem set out their provisional thinking in light of the work of the Group with the intention of providing further context to inform any potential change proposals being considered by industry parties. Specifically, Ofgem noted the importance that transmission charging arrangements reflect the costs imposed on the transmission network and give appropriate credit for benefits provided on the grounds that this promotes the economic development of the transmission network and helps to ensure that competition in generation and supply takes place on a level playing field. Additionally, Ofgem noted the importance that transmission access is allocated in an efficient and coordinated manner and that the administrative and regulatory burden for smaller participants in the market is proportionate.

The group did not initially take into account the time limited nature of the small generator discount (equal to 25% of the residual charge), which was later addressed by Ofgem through the amendment of Standard Licence Condition (SLC) C13 of the electricity transmission licence. In addition to extending the expiry date for the discount from 31 May 2009 to 31 March 2011, this amendment to SLC C13 strengthened National Grid's obligation to use 'best endeavours' to develop and implement enduring arrangements.

Delayed somewhat by progress in the Transmission Access Review, National Grid has discussed the process for progressing SLC C13 at the Transmission Charging

[1] All documentation from the TADG working group can be found at: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TADG/Pages/TADG.aspx

[2] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TADG/Documents1/070723_Final_TADG_Working_Group_Report.pdf

[3] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TADG/Documents1/070730_TADG_Covering_Letter_final.pdf

Methodology Forum (TCMF) and Charging Issues Standing Group (CISG)[4]. Through these discussions with industry parties, National Grid has identified several potential solutions, along with a timeline for implementation, which could more accurately reflect the difference in the transmission cost associated with connecting a generator to the distribution rather than transmission system. They also provide consistency with our duty to be economic and efficient as well as better meet the objectives of the charging methodology. In doing so the proposals provide a more cost-reflective signal for distribution connected generation of the impact they may be causing through increased transmission investment, as well as any benefit they may receive from competition with directly connected generation (despite not necessarily having access to the same market), taking into account any benefit derived from embedding.

Together these changes ensure that parties who choose to connect to the distribution system are doing so efficiently and that there is not a perverse incentive to embed by receiving an arbitrary competitive advantage over transmission connected generation. In addition, through the enhanced cost-reflectivity, charges can provide more effective investment signal to transmission owners.

The importance of these issues will clearly depend on to what extent directly connected generation and distributed generation are in competition with one another. Views are sought on the extent to which this is the case.

Q1 To what extent are directly connected and embedded generators in competition? What evidence do you have to support this view?

Prior to a detailed assessment of proposals, Ofgem's principles for change are considered in more detail, below.

i) Cost-reflectivity

What is causing the issue?
The current Transmission Network Use of System (TNUoS) charges are applied separately to demand and generation and are based on a combination of locational tariffs (calculated using the Transport Model[5]) and additional flat tariffs (the residual elements), together collecting the allowed revenue of transmission companies. The incongruence of zoning aside, locational elements of generation and demand tariffs would be equal and opposite within a given charging zone.

At present, unlicensed DG is treated as negative demand in TNUoS charging. It therefore avoids the TNUoS generation tariff and, subject to negotiation between the DG and associated supplier, is paid the TNUoS demand tariff by its relevant supplier. If tariffs were purely locational in nature (i.e. ignored the need to collect revenue) this would result in an arrangement that is much more cost-reflective. Directly connected generators would pay the locational generation tariff, and embedded generators would be paid the locational demand tariff. Provided the locational generation and demand tariffs are equal and opposite, this would lead to a consistent treatment. However, this arrangement would not facilitate the collection of transmission companies revenues required to pay for the cost of installing, operating and

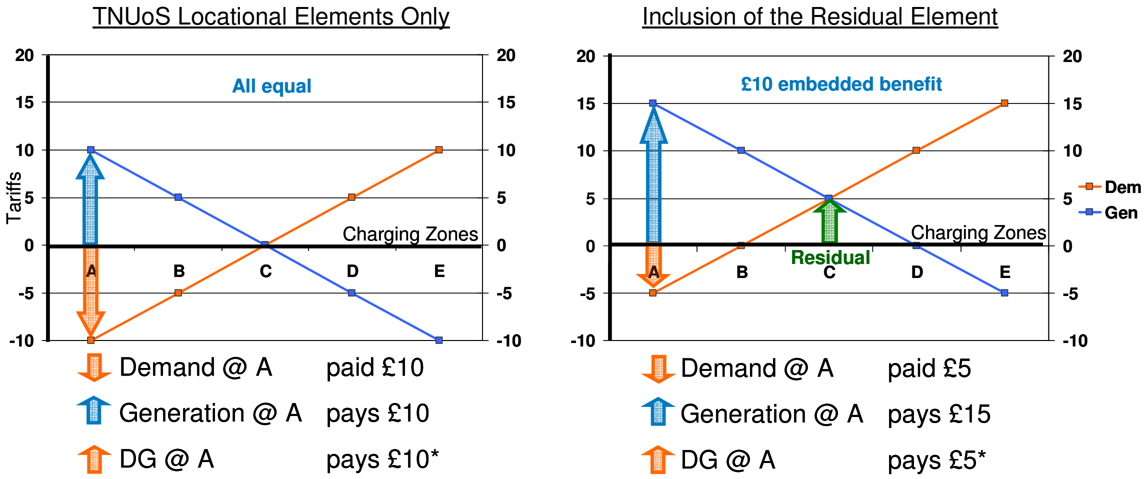
[4] http://www.nationalgrid.com/NR/rdonlyres/5E8C42F8-AA1F-43BD-9941-F253EF91A53B/37271/EmbeddedNG.pdf
[5] DC Load Flow Investment Cost Related Pricing – Transport Model. More information available at http://www.nationalgrid.com/uk/Electricity/Charges/transportmodel/

maintaining the transmission system. It is for this reason that a flat, residual element is necessary. The non-locational nature of this residual element, coupled with its significant relative size (approximately 85% of total revenue collection[6]), results in a net TNUoS benefit to DG over transmission connected generation.

The size of the overall embedded benefit described above is equal to the sum of the residual elements of the generation and demand tariffs, as illustrated below in the simple example shown in Figure 1. This high-level illustration represents a network with 5 zones and an overall power flow from zone A to zone E at peak demand conditions (i.e. zone A has a generation surplus over demand with the converse being true for zone E). The locational elements of the tariff reflect the fact that additional *generation* in zone A would *increase* the amount of transmission capacity required (i.e. the tariff is positive) and that additional *demand* in zone A would *decrease* the transmission capacity required (i.e. the tariff is negative). This equal and opposite effect is reflected in the relative tariffs for generation and demand in this zone. The subsequent addition of the residual element of the tariff, illustrated in the graph on the right of Figure 1, skews this balance and results in a net embedded benefit of the sum of the residual elements of the demand and generation tariffs. This effect is explained in further detail within Annex 1.

[6] For a breakdown of the GB Regulatory Asset Value components vs. locational and non-locational elements of TNUoS, see page 22 of GB ECM13 available at: http://www.nationalgrid.com/NR/rdonlyres/BBBBA243-FB9A-4046-BB95-AE35965B613B/32419/GBECM13Consultationv10.pdf

Figure 1 – Illustrative Effect of the Residual on Embedded Benefit



*Note: in practice DG will be paid demand charges, as they are currently collared at £0/kW in the methodology

What is the potential scale of this issue?

In an attempt to discover a reflective level for the embedded benefit, National Grid has undertaken some analysis to determine the extent of the potential savings in transmission investment as a result of a generator deciding to connect to the distribution network in preference to the transmission network. These savings take the form of the avoided costs in connecting new generation to the transmission network and the avoided investment in demand substation assets resulting from the reduction in net demand at a Grid Supply Point (GSP). Based on historic and planned future levels of investment as well as historic and forecast levels of demand growth, a cost-reflective embedded benefit is estimated to be in the region of between £6.50/kW and £7.25/kW (the rationale behind this is explained in greater detail in Section 3). By contrast, the current embedded benefit provided by the existing transmission charging arrangements, as described above, is in the order of £20/kW.

ii) Access Allocation

Transmission access arrangements have historically not provided a level playing field for transmission and distribution connected generation. Whilst generation projects wishing to connect to the transmission network could be offered connection dates by the NETSO well into the future, as a result of the transmission reinforcement works required to connect them, other generators could potentially avoid the need to wait for these works by opting to connect to a distribution network.

Going forward, the playing field of network connection dates between transmission and distribution connected generation will level somewhat. As part of the 'Improving Grid Access' consultation document[7], the Department of Energy and Climate Change (DECC) set out their intention to move towards the enduring allocation of transmission access on a 'Connect and Manage' basis and that this should apply equally to DG. By removing the need to wait for the completion of 'wider' transmission network reinforcements the connection dates for all generators should better align with the timescales of the generation projects themselves. A knock on effect of a 'Connect and Manage' regime could be an increase in the cost of operating the system. Hence, a review of arrangements for the allocation of Balancing Services Use of System (BSUoS) charges is also required.

[7] http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

If contractual arrangements are not developed in parallel, this has the potential to exacerbate existing difficulties with investment planning, demand forecasting, timing of operational outages and fault level planning. Whilst not insurmountable, the transmission issues caused by increased volumes of DG connecting to the distribution networks in shorter timescales are significant in practice. In some cases the issues are such that the current contractual framework is no longer fit for purpose.

iii) Proportionality

With the aforementioned issues in mind, Ofgem noted in the cover letter to the 'TADG working group report and next steps' that the administrative and regulatory burden for smaller participants in the market should be appropriate[8]. In addition, the minimisation of implementation costs was a key consideration of the TADG working group. Agency models, where small generators would not have a direct contractual relationship with the NETSO, where favoured for their perceived proportionality.

In moving away from the current net supplier arrangement, Ofgem's provisional views set out in the letter also noted that fundamental reform of the exit arrangements added significant complexity and noted that this may be a disproportionate response to the issue[8]. Some benefits of a gross charging model in terms of simplicity over a net charging model were outlined as well as the need to consider the appropriateness of a threshold below which DG would be automatically be treated as net for practical reasons.

We note that a gross nodal supplier agency arrangement maximises use of the existing commercial frameworks (and so could be considered commercially proportional) as well as minimises the amount of change and cost required for implementation.

However, given the emergence of 'smart grid' technology and its potential to lead towards a role of more centralised control for Distribution Network Operators, it may be prudent to pursue the net DNO model despite the complex reforms required to deliver an acceptable solution under this model.

Q2 To what extent should potential future requirements to facilitate 'smart grids' influence current change proposals for DG? Could this exclude certain options?

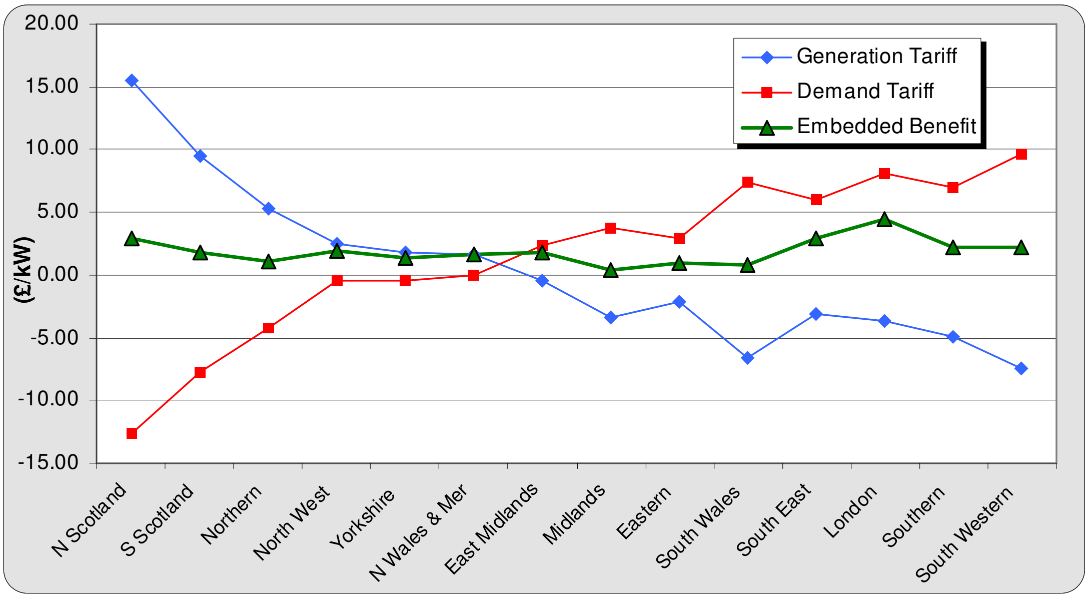
[8] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TADG/Documents1/070730_TADG_Covering_Letter_final.pdf

3.0 Analysis – Defining the Embedded Benefit

As outlined in the introduction, the TNUoS tariff comprises two separate elements. Firstly, a locationally varying element derived from the Transport Model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locational element that relates to the provision of residual revenue recovery. The combination of both these elements forms the overall TNUoS tariff.

Subject to zoning, the locational elements of TNUoS demand and generation tariffs are the equal and opposite of each other in the same location. Where a transmission connected generator pays the locational TNUoS generation tariff determined by its location, a generator connected to the distribution system is effectively paid the demand tariff dependent on location by its relevant supplier (subject to negotiation) which nets the DG from that suppliers demand. Assuming 100% pass-through of the avoided demand tariff by the supplier, Figure 2 identifies that locational TNUoS tariffs result in an average, inherent embedded benefit of ~£2/kW, this being the result of the use of differing 'relevant' nodes when calculating the flow-weighted marginal km for demand and generation zones respectively[9]. It should be noted that for illustrative purposes, TNUoS generation zones have been modelled as TNUoS demand charging zones to enable a direct comparison to be drawn in the analysis that follows.

Figure 2 – Locational TNUoS Tariffs & Inherent Embedded Benefit



Based on 2007/8 charging data

Whilst the gross revenue flows for payment of locational generation and demand tariffs in 2007/8 amounted to approximately £550m, net payments from demand and generation parties amounted to approximately £180m (only ~15 percent of allowed revenue). For the 2007/8 charging year, approximately £1.05bn of revenue was therefore recovered from generation and demand users on a 27/73 percent revenue split basis, from the residual generation and demand tariffs which were ~£3.87/kW and ~£14.06/kW respectively.

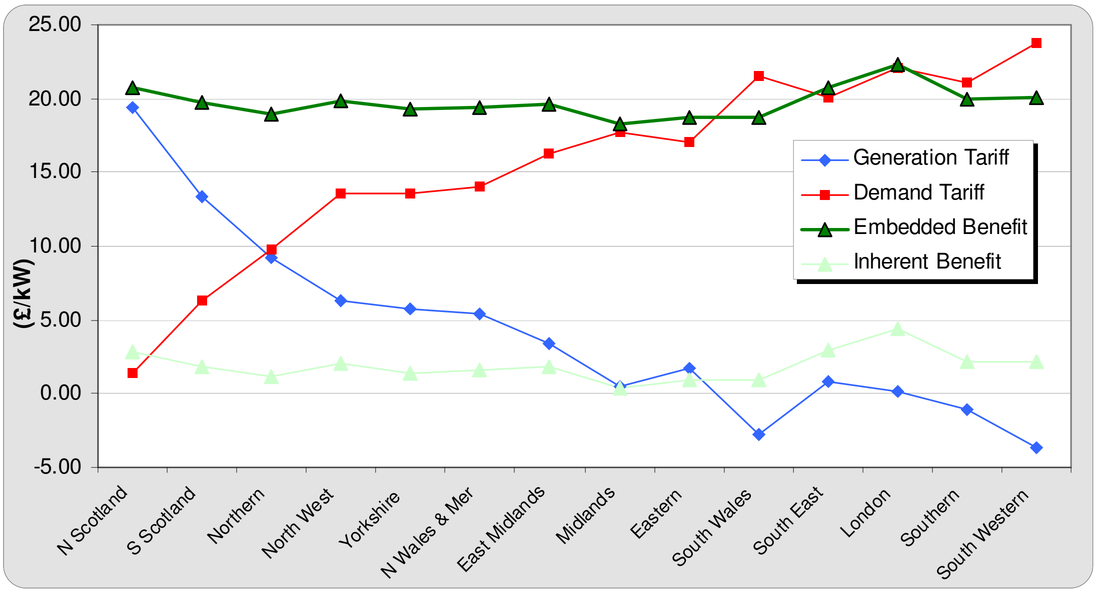
9 As illustrated in the TNUoS Demand Zones and TNUoS generation zones maps, available at: http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

3.1 The Residual Effect

When adding the relevant residual elements to the locational tariffs, this has the effect of increasing both TNUoS generation and demand tariffs such that the actual average embedded benefit becomes ~£20/kW, representing the sum of both the generation and demand residual tariffs of ~£18/kW plus the inherent embedded benefit of ~£2/kW described above. This is illustrated using actual 2007/08 data in Figure 3, below, and the concept explained in further detail in Annex 1.

Whilst in practice this value varies slightly, dependent on the exact location of a generator within its TNUoS generation zone, the sum of the residual tariffs are considered to be a good proxy for determining the current benefit to a generator of connecting to the distribution system rather than the transmission system in any location. This benefit is defined relative to the transmission tariff which a generator connected to the transmission system in that same location would be subject to.

Figure 3 – Total TNUoS Tariffs and Full Embedded Benefit (inc. Residual Effect)



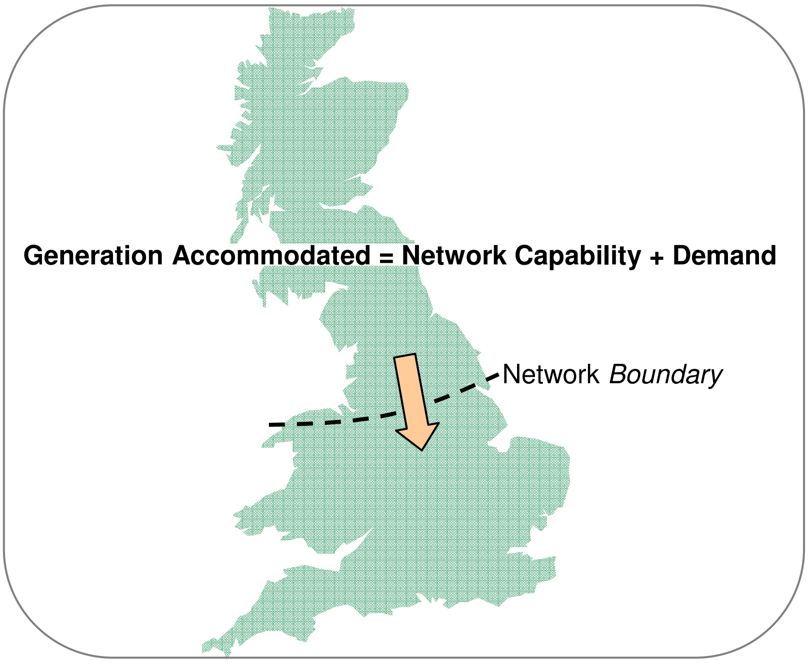
3.2 Impact of DG on Transmission

Many of the misconceptions over the impact of connecting generation to either the transmission network or distribution network arise from the traditional view of transmission and distribution as two separate networks. Whereas, they are in fact one contiguous electrical system within which a change in one area impacts on the entirety of the system.

For a given network capability between two parts of the transmission system (referred to as a *boundary*), the amount of generation that can be accommodated on the exporting side of the boundary is a function of the demand in that area of the network. Therefore an increase in the amount of DG, reducing local demand behind the boundary, has the same impact on that boundary as generation connected directly to the transmission network. This remains the case regardless of whether the amount of DG exceeds the demand within a particular GSP (i.e. becomes an exporting GSP) or the DG simply has the net effect of reducing demand.

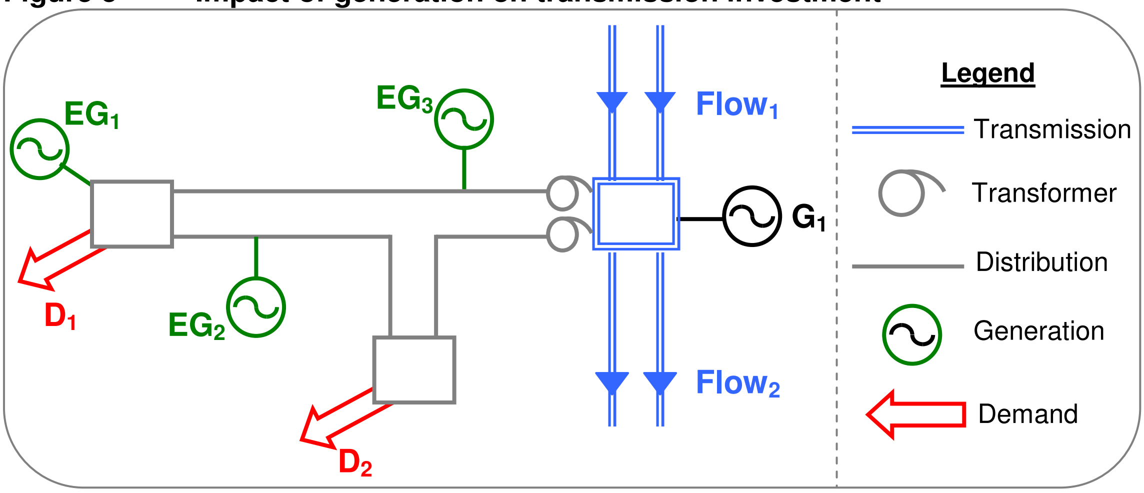
It is instructive to step back and consider the transmission network *boundary* between two parts of the transmission system when conceptualising this issue. Due to the amount of electricity generation exceeding the demand in the northern part of the system, net power is normally exported towards the south. Hence, any reduction in the amount of demand within this area will result in a reduction in the amount of generation that can be accommodated in that area. This is illustrated below in Figure 4.

Figure 4 High level example of DG impact on transmission investment



At a more detailed level Figure 5, below, shows a directly connected generator (G_1) and embedded generators (EG_1, EG_2 and EG_3) at the same transmission substation (GSP). The required capacity of the transmission lines (the 'Flow' in MW) is the sum of the directly connected and embedded generators minus the demands (in MW). Therefore increased output from the directly connected or embedded generators would have the same impact on the investment required (either increased or decreased) in the transmission circuits to accommodate $Flow_2$ in MW.

Figure 5 Impact of generation on transmission investment



$$Flow_2 = Flow_1 + G_1 + (EG_1 + EG_2 + EG_3) - (D_1 + D_2)$$

This concept is important when considering the practical and technical impacts on the two networks as well as the effectiveness of cost-reflective signals in signalling the incremental cost of the network to all those contributing to that cost.

3.3 Avoided Transmission Investment – The 'De-facto' Embedded Benefit

This paper has attempted to demonstrate the impact that DG can have on the transmission network. Nevertheless, a generator that chooses to embed within the distribution network clearly has the net effect of reducing the investment required at the interface point between the distribution and transmission networks. In addition, some of the costs associated with connecting a generator to the transmission system are also avoided. National Grid has undertaken some analysis in order to quantify the de-facto benefits of avoided transmission investment associated with a generator deciding to connect to the distribution network in preference to the transmission network in the same location. This has been subject to discussion at the TCMF and its subgroup, the CISG in the past[10].

As outlined above, the avoided transmission costs associated with the distributed generator is limited to two categories; the transmission investment which would have otherwise been incurred as a result of increasing demand at a relevant GSP; and the investment which would have otherwise been incurred in connecting new generation to the transmission system.

Avoided GSP Investment

Using demand growth figures from between 2000 and 2006 and the actual levels of transmission investment arising as a result, in addition to forecast 2006-2012 demand figures and planned levels of investment, the savings in local transmission investment associated with demand growth are estimated to be in the region of £5.00/kW and £5.75/kW in today's prices.

Avoided Generation Connection Investment

In assessing the levels of transmission investment avoided from generation connecting to the distribution networks in preference to the transmission system, National Grid's revenue drivers which form part of the 2007-12 Price Control Review settlement[11] were used. The average additional costs incurred (or avoided) in connecting more (or less) new generation than assumed in the baseline for England & Wales, equates to an annuitised value of approximately £1.50/kW when using this method. The differences between TNUoS and Revenue Drivers mean that it is not possible to compare them directly in many circumstances[12]. However, in the approximation of investment savings associated with avoided generation investment this was considered a reasonable approach.

Using this basis as a proxy for determining the actual value of avoided transmission investment as a result of a generator choosing to connect to a distribution network, this can be estimated to be in the region of between £6.50/kW and £7.25/kW under the current transmission arrangements, when calculated on a capacity basis and

[10] http://www.nationalgrid.com/NR/rdonlyres/3F26A596-B935-41CA-9405-74429133D3E5/20852/EmbeddedGenerationOct2007TCMFfinal.pdf

[11] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/16342-20061201_TPCR%20Final%20Proposals_in_v71%206%20Final.pdf

[12] This was discussed in TAR working group 2: http://www.nationalgrid.com/NR/rdonlyres/7726F56A-639B-483A-8045-35BB38CED969/28046/CAP165revisedalternative.pdf

assuming that the embedded generator will generate at full capacity during periods of system peak demand.

This issue is therefore that, under the prevailing transmission charging arrangements, the value of revenue recovered from the residual elements of transmission tariffs results in tariffs that from a charging perspective alone may provide an incentive for a generator to embed within the distribution network. With a difference of approximately £13/kW in excess of the actual savings in transmission investment that could be realised, this is potentially quite a strong, inefficient signal informing the investment decisions of small generators.

Q3 Is the methodology used to derive a 'de-facto' value of the embedded benefit appropriate? If not, can you suggest an alternative method?

3.4 Commoditisation of the Residual Tariffs

As part of the Transmission Access Review (TAR), consideration was given to the commoditisation of the residual element of the TNUoS generation and demand tariffs and, going forward, it is possible that this will form one element of an improved charging regime. However, the effect of this change on the embedded benefit is easily misunderstood and there is a misconception that the commoditisation of residual tariffs removes or reduces the level of the embedded benefit to more cost-reflective levels.

In practice, the commoditisation of the residual tariffs alone (levied on a £/kWh energy basis) fails to address the issue of cost-reflectivity of transmission charges for DG in the same location as a transmission connected generator. Table 1 illustrates the impact on tariffs of DG by generation type and assumed load factors, when compared to a transmission connected generator in the same location with the same load factor (as above, assuming 100 percent pass through of tariffs from the supplier).

Table 1 Illustrative Embedded Benefit

Generator Type	Assumed Load Factor	Embedded Benefit
Wind	27%	~£9.80/kW
Hydro	37%	~£12.80/kW
CHP	65%	~£20.90/kW
Other	52%	~£17.10/kW
Average	**56%**	**~£18.30/kW**

For relatively low load factor plant such as wind and hydro the embedded benefit is reduced to what could be considered as more cost-reflective levels, when the residual element of the TNUoS tariffs is levied on a commoditised basis, given the analysis presented in Section 3.3, above. For average load factor plant however, the embedded benefit remains at those levels provided by the current transmission charging arrangements. Commoditisation in itself is therefore not a solution to the issue of the embedded benefit. Nevertheless, National Grid does not consider that this precludes the commoditisation of the residual element of the tariff as part of a wider solution to charging issues.

Could a commoditised residual be accommodated as part of a solution?

Based on the analysis provided at the start of Section 3, by continuing to levy the locational element of the TNUoS tariffs on a capacity basis, there would remain an inherent embedded benefit of ~£2/kW from the locational tariff. The majority of the embedded benefit, in this case would subsequently be derived from the commoditised residual tariff and therefore vary dependent on the load factor of the embedded generator (as demonstrated in Section 3.4).

In order to achieve a cost-reflective embedded benefit under a commoditised residual charging regime, the involvement of suppliers may be required. This requirement arises out of the need to provide the DNO with accurate metering data for each embedded generator from that relevant supplier, whilst a DNO / generator specific 'adjustment' would be required dependent on the load factor of the relevant generator, to arrive at a cost-reflective embedded benefit. Consideration would also need to be given to the treatment of 'peaking plant' which under a commoditised regime, would receive a relatively small embedded benefit due to operating only at times of peak transmission system demand, yet serve to reduce transmission investment.

3.5 Threshold(s) Associated With Requests for a Statement of Works

CAP097: "Revisions to the Contractual Requirements for Small and Medium Embedded Power Stations" was raised by National Grid in June 2005[13] seeking to clarify National Grid's requirements for the provision of information regarding small and medium sized embedded power stations for the provision of information to enable National Grid to accurately assess the impact of an embedded development on the transmission system. Within the amendment proposal, National Grid presented its view that the cumulative impact on the transmission system of smaller power stations connecting to a distribution system can be equivalent to the impact of a single large embedded power station and noted that there are circumstances where a proposed small or medium sized embedded power station could trigger wider transmission system reinforcement works.

Following a Working Group Report[14] and subsequent Consultation[15], Consultation Alternative Amendment 2 (CAA2), proposed by EDF Energy was approved by the Authority in June 2006[16]. In summary, CAP097 CAA2 requires a DNO to make a request for a Statement of Works from National Grid in respect of proposed embedded medium sized generators (<100MW and =>50MW NGET), whilst for proposed embedded small generators (<50MW NGET, <30MW SPT, <10MW SHETL), such a request is only required where that DNO believes that the proposed small power station connection may have a significant impact on the transmission system.

In National Grid's view, it is questionable whether a DNO is best placed to determine whether or not a small embedded power station development has a significant effect on the transmission system. In practice, due to the wide range of issues which need to be considered and the varying interpretation of these, it has not always been possible for National Grid to agree with the DNO's assessment as to when the

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13 http://www.nationalgrid.com/NR/rdonlyres/4A0EA597-1BB5-4FA1-BE8A-3D8CFBBD66B1/3156/CAP097CUSCchangesforMediumPowerStationsassociated.pdf

14 http://www.nationalgrid.com/NR/rdonlyres/B40EBC83-973F-4CCC-B234-12641FB92BA1/4406/CAP097WGReportv11.pdf

15 http://www.nationalgrid.com/NR/rdonlyres/C9784928-AA5E-48D2-8AE0-08F4F6F2E60C/4646/Consultation_CAP09711.pdf

16 http://www.nationalgrid.com/NR/rdonlyres/8A959F56-6709-477E-80D7-16165310AE79/7536/CAP097D.pdf

development of a small embedded generator has a significant impact on the transmission system.

Consequentially, National Grid raised CAP167 at the May 2008 CUSC Panel Meeting with the aim of providing definitive clarification in the assessment of whether a small embedded power station development has a significant impact on the transmission system with a transparent trigger to notify a DNO of when a Statement of Works is required.

Whilst it is intended that CAP167 will improve the visibility of DG to National Grid, the proposal does not offer a solution to the issue of cost-reflectivity in TNUoS charges, or address the gap in the contractual framework with respect to GSPs which export onto the transmission system.

The following section of this document presents two alternative, enduring solutions, each of which goes some way towards resolving the problems identified above, in the form of a Gross Nodal Supplier Agency Model (GNSAM) straw man and a Net DNO Agency Model straw man.

4.0 Potential Enduring Solutions

This section presents two possible enduring solutions to the issues raised in this paper with the intention of stimulating industry debate on both, and highlights the issues associated with each of them. Industry views are requested on the pros and cons of each solution.

In addition to the impact on the amount of investment in transmission capacity required, explained above, the times at which DG runs will also impact on the total cost of operating the system. Therefore, the efficient allocation of this cost, recovered through BSUoS charges, will also have to be addressed in any enduring solution.

4.1 Gross Nodal Supplier Agency Model

During the TADG process, National Grid proposed and supported the development of a GNSAM, based on the following key assumptions:

- Output from a directly connected and a DG will lead to broadly similar levels of wider transmission infrastructure investment (see Figure 4 and 5 in Section 3.2);
- DG competes with directly connected generation for network access;
- DG benefit from competition with directly connected generation in terms of the price they receive for electricity generated; and
- Charging arrangements should be largely cost-reflective.

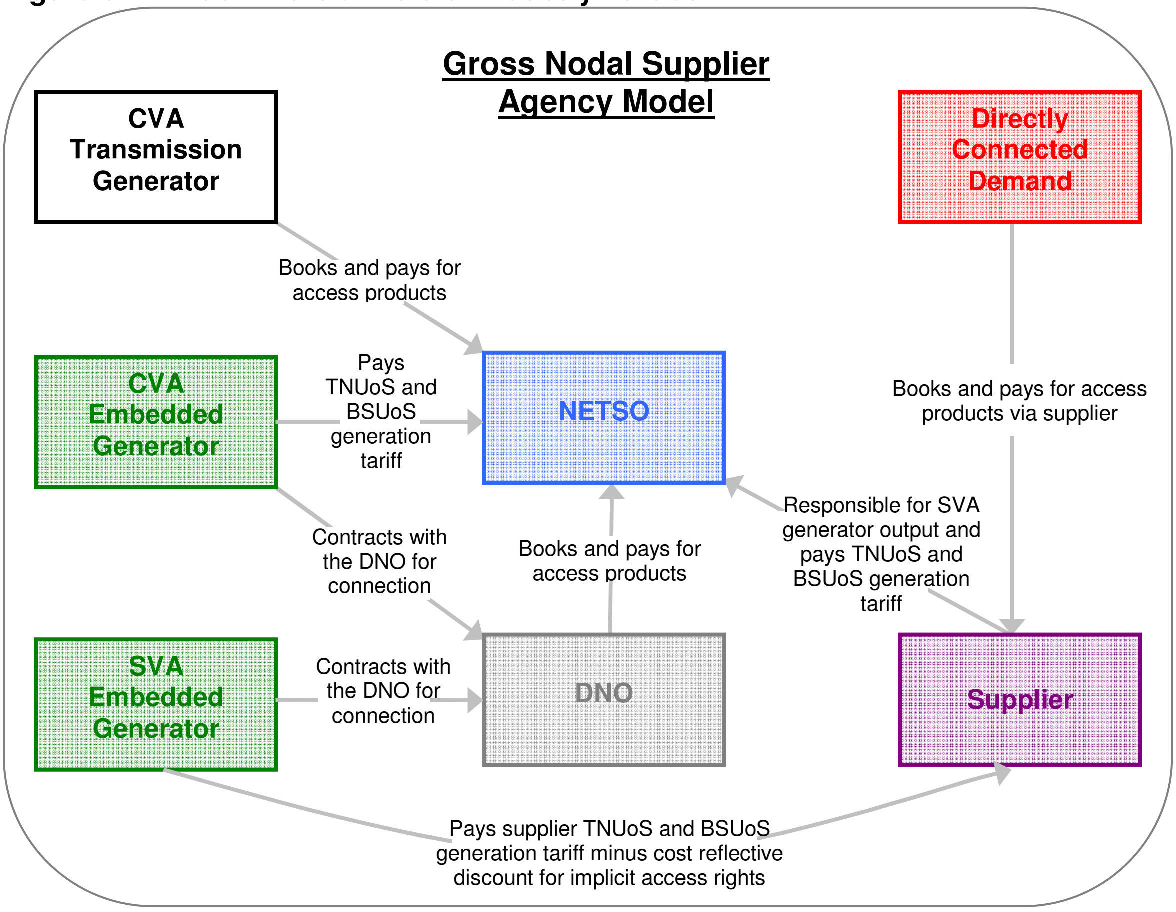
In terms of improving access for new generation, this is expected to be largely addressed through DECC's 'Improving Grid Access' consultation[17]. However, ongoing access implications in terms of constraint costs will continue to prevail

The GNSAM seeks to address the above issues associated with DG by treating all generation (both directly connected to the transmission system and embedded in the distribution networks) equally for transmission charging purposes, except for a cost-reflective discount applied to the generation tariff levied on DG, reflecting the avoided investment in the transmission network (see Section 3.3).

An overview of the roles of industry parties and some of the implications for each under a GNSAM can be summarised as follows:

[17] Some access issues over the 'local' connection work for new connectees may remain

Figure 6 Commercial Role of Industry Parties



National Electricity Transmission System Operator

- NETSO levies TNUoS and BSUoS generation tariff on the supplier, for the Supplier Volume Allocated (SVA) registered embedded generator for which they are lead party.
- NETSO levies TNUoS and BSUoS generation tariff directly onto Central Volume Allocated (CVA) registered embedded generation.
- TNUoS and BSUoS generation tariffs levied on all generation in excess of a pre-determined threshold based on TEC or “DGTEC”, thus increasing the generation charging base. (For the purpose of this pre consultation, the term “DGTEC” is introduced to differentiate between TEC obtained by transmission connected generation and that access obtained by DG)
- Residual element of the TNUoS generation tariff could remain TEC / triad-based or commoditised, dependent on the outcome of wider framework changes made to entry arrangements subsequent to the government’s decision on access arrangements.
- TNUoS demand tariffs levied on a gross demand basis, increasing the demand charging base.
- Residual element of the TNUoS demand tariff could remain triad-based or be commoditised.
- Tariffs for both DG and demand calculated based on nodal data and levied on a zonal basis. This could require nodal BMU data from DG for settlement purposes.
- Generation tariff for both SVA and CVA registered embedded generator is equal to the TNUoS generation tariff for a transmission connected generator in the same location, minus a discount (in the order of £6.50/kW - £7.25/kW) to reflect

the avoided local transmission investment costs resulting from the generators decision to connect to the distribution network in preference of the transmission network.

Central Volume Allocated registered embedded generator

- GNSAM represents no change to the CVA registered embedded generator from the current transmission charging arrangements for >100MW, other than the payment of a TNUoS generation tariff which reflects the associated savings in transmission infrastructure as a result of that generator connecting to the distribution network, by way of a cost-reflective discount in the order of £6.50/kW to £7.25/kW.
- CVA registered embedded generators <100MW and in excess of a pre-determined threshold become liable for TNUoS generation tariffs (minus the cost-reflective discount) and BSUoS and are no longer credited with the TNUoS demand tariff by the relevant supplier.
- CVA registered embedded generator contracts with the DNO for connection to the distribution network and is subjected to the relevant Distribution Use of System (DUoS) and connection tariffs.

Supplier Volume Allocated registered embedded generator

- SVA registered embedded generator becomes liable for TNUoS generation tariff (minus the cost-reflective discount) and BSUoS, payable to the relevant supplier.
- SVA registered embedded generator no longer credited with the TNUoS demand tariff by the relevant supplier.
- SVA registered embedded generator contracts with the DNO for connection to the distribution network and is subjected to the relevant DUoS and connection tariffs.

Supplier

- Supplier is responsible for all transmission charges associated with the embedded generator for which it is the lead party, proportional to the length of time for which it is the lead party within a charging year.
- Supplier is responsible for resolving SVA registered DG Transmission Entry Capacity “DGTEC”.
- Supplier adopts all CUSC rights and obligations on behalf of the SVA registered generator for which it is the lead party (i.e. the obligation not to exceed DGTEC).
- Supplier is responsible to the DNO to ensure that all changes in output can be facilitated by the DNO.

Distribution Network Operator

- Current CUSC 6.5 relationship between the NETSO and the DNO would continue.
- The Statement of Works will indicate data, communication or control requirements that the NETSO requires.
- In addition, the application for a Statement of Works will include a DGTEC figure.

Operational impact

National Electricity Transmission System Operator

- NETSO responsible for adjusting embedded generation either through a supplier Balancing Mechanism Unit (BMU) in the Balancing Mechanism (BM) or by despatching SVA registered generation directly under a new contractual relationship with the supplier. Whilst this may alleviate transmission congestion, this could be at the expense of exacerbating distribution constraints.

- NETSO needs to know how adjustments to DG will affect individual super grid transformer (SGT) flows.

Distribution Network Operator

- DNO becomes active and is responsible for confirming the extent to which products can be despatched by the NETSO in real time through the BM.
- Impact on the DNO network requires further assessment.

Cost-reflectivity

The GNSAM provides TNUoS tariffs which reflect the costs of investment in the transmission network as a result of generation connecting to both the transmission and distribution networks. National Grid considers that a cost-reflective tariff for DG would be the TNUoS and BSUoS generation tariff levied on transmission connected generation, minus a discount reflecting the avoided local investment, as they drive (or avoid) the same wider transmission investment.

National Grid considers that an appropriate discount for the avoided local investment would be in the order of between £6.50/kW and £7.25/kW. Such a discount would ensure that DG is liable for cost reflective TNUoS tariffs with DG effectively seeing the same signal as a generator looking to connect to the transmission system in that same location. The GNSAM is flexible in its design in that the discount could be a generic discount applied to all DG across GB or alternatively, a DG specific discount calculated based on the exact transmission savings resulting from the generators decision to connect to the distribution network. At this stage, National Grid considers that a single generic discount might be the preferred option on the grounds that this is more simple to implement and transparent to Users.

Access allocation

Under the GNSAM, if an embedded generator wishes to obtain or increase its level of DGTEC at a GSP, it will be required to apply to the NETSO via the DNO and the Statement of Works process. This ensures equitable allocation of transmission access regardless of whether a generator intends to connect to the distribution or transmission networks, subject to a de minimis MW level.

The implementation of a GNSAM as an enduring solution would address the current gap in the contractual framework with respect to GSPs which export onto the transmission system.

Commercial proportionality

National Grid considers that implementation of a GNSAM would require some major changes to industry codes and systems, including:

Connection and Use of System Code

- Changes required in order to clarify the revised role, rights and obligations of the supplier in respect of DG.
- Review the role of Licence Exempt Embedded Medium Power Stations (LEEMPS), Bilateral Embedded Licence Exemptable Large Power Station Agreements (BELLAs) and the role of the DNOs, particularly for CUSC 6.5.

Grid Code

- Changes required in order to clarify the role of the supplier in respect of embedded power stations (e.g. supplying data and despatch in the balancing codes).

Balancing & Settlement Code

- Consequential changes following on from the changes to the CUSC. Principally, seeking to ensure that the obligations on parties are consistent (e.g. the requirement for supplier generation BMUs and the extent to which a supplier can net (or not) will need to be consistent with the CUSC).
- There may be a requirement for additional metering information to support transmission charging systems.

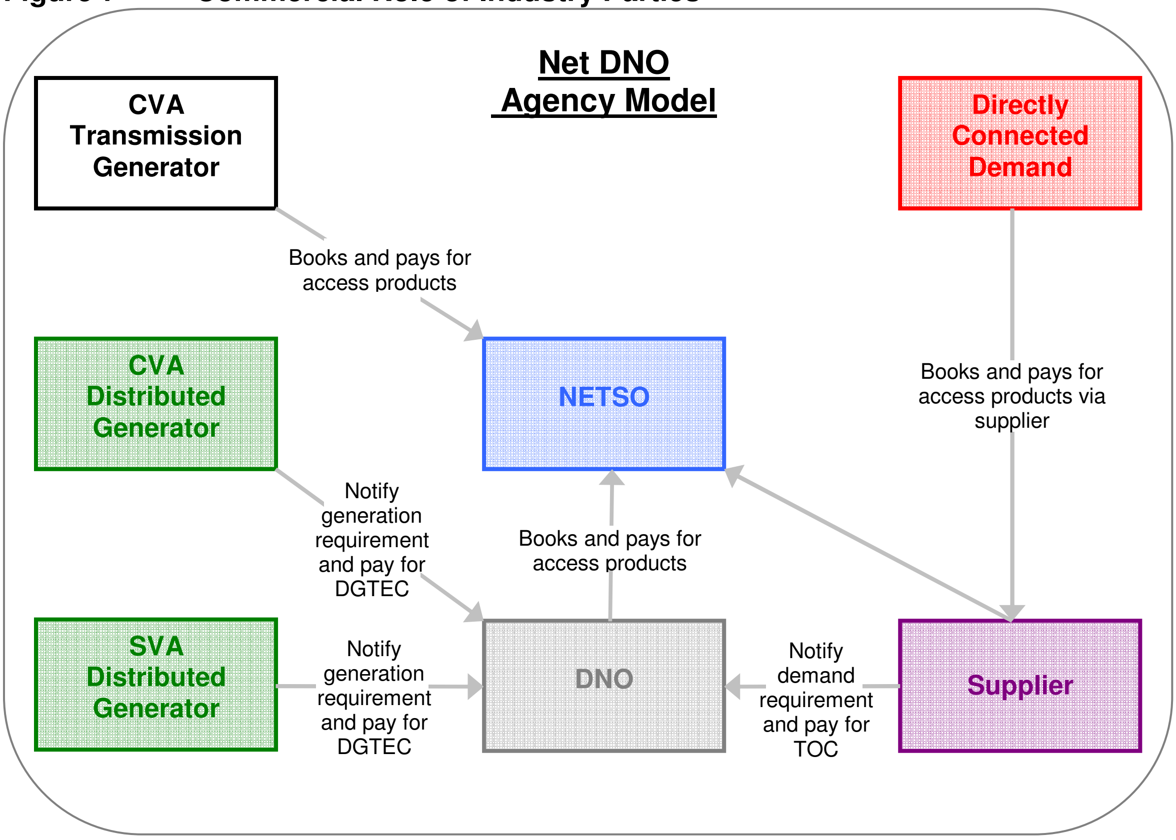
Additionally, changes would be required to the transmission charging methodologies, the Distribution Connection and Use of System Agreement (DCUSA), the Distribution Code, and the BM registration and settlement systems.

4.2 Net DNO Agency Model

Unlike the GNSAM, net models treat embedded generation as negative demand. The implicit access arrangements for demand within the current transmission charging arrangements however, lead to disproportionate treatment between transmission and distribution connected generation. The Net DNO Agency Model seeks to address this from an access allocation perspective, by placing a requirement on Users to book firm exit products in the form of Transmission Offtake Capacity (TOC). However a model based on net charging does not explicitly address the issue of cost-reflectivity.

An overview of the roles of industry parties and some of the implications for each under a DNO Agency Model can be summarised as follows:

Figure 7 Commercial Role of Industry Parties



National Electricity Transmission System Operator

- NETSO levies TNUoS and BSUoS generation and demand tariff on DNOs, directly connected demand or directly connected generation on a net basis.
- Tariffs (both generation and demand) calculated based on nodal data and levied on a zonal basis, based on a winter peak demand scenario.
- Locational element of the TNUoS tariff calculated and charged based on TEC / DGTEC / TOC.

Distribution Network Operators

- Responsible for booking DGTEC on behalf of GSPs which export onto the transmission system and directly liable for TNUoS generation tariff.
- Responsible for booking Transmission Offtake Capacity (TOC) for each GSP by netting their notified DGTEC/TOC requirements and directly liable for TNUoS demand tariffs.
- Incentives would be required to ensure that DNOs book appropriate levels of capacity and accurately pass these costs through to Users.
- Responsible for booking (and paying for) available exit products at each respective GSP.

Embedded generator

- Responsible for notifying (and paying for) the relevant DNO of DGTEC requirement.

Supplier

- Responsible for booking (and paying for) TOC from the NETSO on behalf of directly connected transmission demand Users.
- Responsible for booking (and paying for) short-term access products from the GBSO on behalf of directly connected transmission demand.
- Responsible for notifying (and paying for) the relevant DNO of their demand requirement.

Directly connected generator

- Responsible for booking TEC directly from the NETSO and directly liable for relevant TNUoS generation tariff.
- Responsible for booking short-term access products from the NETSO and directly liable for payment.

Directly connected demand

- Responsible for notifying TOC (and any short-term access) requirements to the relevant supplier.
- Responsible for payment to the supplier.

Operational impact

National Electricity Transmission System Operator

- May require the ability to access bids and offers for imports and exports at each GSP, therefore DNO BMUs required, with mini-BMs (managed by the DNOs) behind each node with embedded generation that the DNO uses to aggregate bids and offers.

Distribution Network Operators

- Responsible for adjusting embedded generation to ensure net output does not exceed requested TEC for exporting GSPs.
- Responsible for operating networks within requested TOC / short-term access parameters.

- Likely to be achieved through the development of a mini BM for each DNO / GSP, which will be managed by the DNO itself.
- An option may be for the DNO to offer a merit stack of bids and offers based on prices submitted by embedded generators, filtered to exclude units that would exacerbate local distribution issues. Appropriate incentives may be required to ensure efficiency.
- This option may better facilitate the introduction of 'smart grids' from an operational perspective, depending on their configuration.

Cost-reflectivity
Whilst the contractual relationship between the NETSO and directly connected generation and demand remains broadly the same, the decision to levy TNUoS tariffs on DNOs represents fundamental change to the current transmission charging regime.

The Net DNO Agency model does not solve the inconsistencies between distribution and transmission connected generators through transmission charging alone. Whilst locational tariffs send a locational signal to generators, the commoditised residual tariffs continue to provide an embedded benefit as transmission connected generation pays the residual generation tariff and DG is paid the residual demand tariff when netting from overall demand at a GSP.

By continuing to treat embedded generation as negative demand, the responsibility for charging DG cost-reflectively becomes that of the DNOs. Whilst transmission charges would accurately reflect the costs for use of the GB transmission network itself, it would be a matter for the DNO to pass these costs through to distribution network Users in accordance with the requirements of its Licence.

Where the impact of DG is such that this results in an exporting GSP, this would be treated as transmission connected generation and the DNO would be liable for the full TNUoS generation tariff, through an entry product for exporting GSPs. It would be for the DNO to pass this cost through to the relevant embedded generator(s) in accordance with its charging methodology and License. However, it is worth noting that where the cost of the access provided might be shared by multiple embedded generators, issues of cost-reflectivity may remain.

Access allocation
For exporting GSPs, the relevant DNO will be required to apply to the NETSO for capacity rights in the same way as transmission connected generation. Where embedded generation reduces demand levels, the DNO could be incentivised to undergo a TOC reduction process, assuming that they are exposed to the cost differential of requested demand versus actual demand.

In the event of 'floating GSPs' whereby it is difficult for the DNO to predict whether that GSP will import or export from/to the GB transmission system at system peak, the DNO may be required to book TEC and TOC as per the current arrangements for interconnector owners. It is worth noting the difficulties which may be associated with forecasting the running profile of intermittent generation at these times, particularly given the forecasting timescales that would be involved. However, as mentioned above, in a world of 'smart grids' the DNO may be best placed to perform these activities.

Commercial proportionality

Whilst potentially representing the optimal solution in terms of the NETSO receiving efficient signals for transmission network development, the major drawback of the Net DNO Agency model in addition to the continued difficulty to charge cost-reflectively between transmission connected and distribution connected generation due to the residual tariff, is the costs associated with implementation and the likely timescales involved. A Net DNO agency Model would require fundamental reform for both entry and exit and subsequent changes to industry codes and systems for both transmission and distribution.

Connection and Use of System Code

- Changes will be required to clarify the revised role of the DNO in respect of DG.
- Development of formally defined TOC product.
- Development of short-term access products for both entry and exit.

Grid Code

- Changes required to clarify the role of the DNO in respect of embedded power stations (e.g. supplying data and despatch in the balancing codes).

Balancing & Settlement Code

- DNO may assume some responsibility for DG.
- Requirement for additional metering information to support transmission charging systems.
- Changes to the BM registration and settlement systems may be required.

Transmission charging methodologies

- TNUoS levied on DNOs, direct connects and generators, therefore modifications required to the existing charging systems.
- Through development of a formally defined TOC product, no longer a requirement to differentiate between Half-Hourly and Non Half-Hourly demand users as residual tariff charged on a commoditised basis.

Distribution Network Operators

- As DNOs will be subjected to TNUoS and BSUoS charges to which they are currently not, it will be necessary to reopen the distribution price controls to ensure that the DNOs are eligible to recover the additional revenue required to meet these costs. Whilst this is a non-trivial step, it is achievable but may lead to further regulation requirements. DNOs could be exposed to the difference between the transmission charges associated with their capacity booking(s) and the receipts from suppliers and embedded generators based on usage.
- Having established a revenue stream, it is likely that the DNOs will be required to amend their current charging methodologies and charging systems.
- It is likely that significant changes to the DCUSA and bilateral agreements with demand Users and embedded generation will be required to facilitate the change in relationship of capacity booking and payment.
- Such arrangements are likely to have a significant impact on the way in which the DNOs operate their network through the use of the BM and mini-BMs.

Q4 Is there anything further that should be considered in the relative merits and implications of the GNASM and Net DNO Agency Models?

Q5	Which model do you think is most suitable when considering the criteria of cost-reflectivity, access allocation and proportionality?

Q6	What are your views on whether the appropriate solution should be gross or net (or a suitable combination of both models), and whether the DNO or supplier would be the most suitable agent?

5.0 Views Invited

Comments on all of the issues contained in this pre consultation are invited by close of business on **26th February**.

More specifically, National Grid would be particularly interested in receiving the views of the industry on the questions raised within this pre consultation. These are repeated, below:

1) To what extent are directly connected and embedded generators in competition? What evidence do you have to support this view?

2) To what extent should potential future requirements to facilitate 'smart grids' influence current change proposals for DG? Could this exclude certain options?

3) Is the methodology used to derive the 'de-facto' value of the embedded benefit appropriate? If not, can you suggest an alternative method?

4) Is there anything further that should be considered in the relative merits and implications of the GNSAM and Net DNO Agency models?

5) Which model do you think is most suitable when considering the criteria of cost-reflectivity, access allocation and commercial proportionality in conjunction with 'Grid Access' developments?

6) What are your views on whether the appropriate solution should be gross or net (or a suitable combination of both models), and whether the DNO or supplier would be the most suitable agent?

If you wish to provide comments on this pre consultation document, responses are preferred via email to: ivo.spreeuwenberg@uk.ngrid.com

Alternatively, interested parties can send their comments in writing, addressed to:

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If you have any further queries, please do not hesitate to contact Ivo on 01926 655897.

Annex 1

Formulation of Benefit

The formula below explains why the TNUoS embedded benefit simplifies down to the sum of the residual elements.

L_i = Locational Charge at point *i*
Rg = Generation residual (at all points)
Rd = Demand residual (at all points)

The locational signal, at a point i on the system, derived from the transport model is L_i[18]. Therefore the generation charge at this point would be:

Generation Charge = L_i + Rg

Where Rg is the generation proportion of the residual amount. This is a flat charge applied to all generation tariffs to ensure cost recovery.

The demand locational signal at point *i* is equal and opposite to that of generation, -L_i, therefore the demand charge would be:

Demand Charge = -L_i + Rd

Where Rd is the demand proportion of the residual amount. As with generation, this is non locational and applied to all demand.

An embedded generator avoids the generation portion of the transmission charge and has the effect of reducing the demand portion of the transmission charge for the associated supplier. Therefore, assuming the supplier passes through the full avoided cost, then the total embedded benefit is:

Embedded Benefit = Generation Charge – Demand Charge
= (L_i + Rg) – (L_i – Rd)
= L_i + Rg - L_i + Rd
= Rg + Rd

From the above, it is clear that the embedded benefit is non locational in nature and works out as the sum of the residual elements of the generation and demand charges.

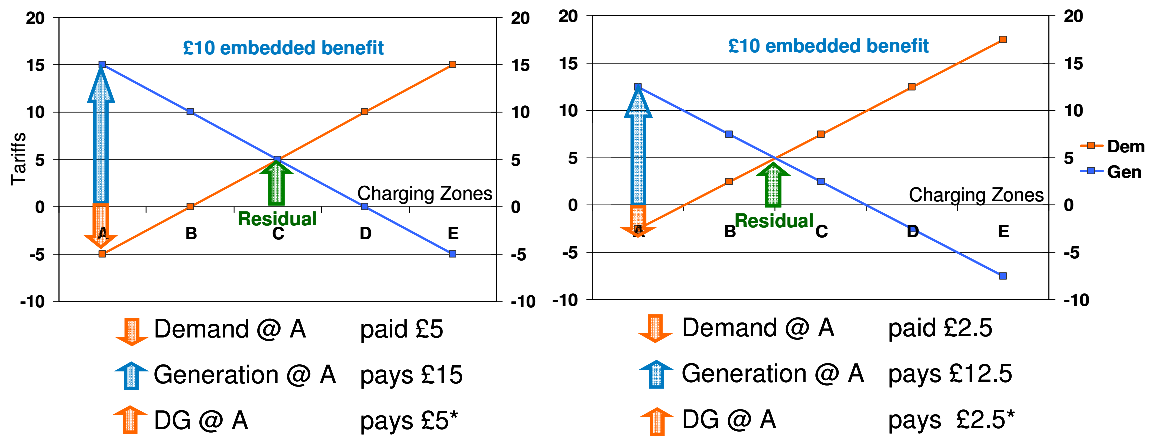
It is this result that calls into question the cost-reflectivity of the embedded benefit as it currently stands and contributes to National Grid's belief of the need to address the residual element of charges.

[18] Includes the referencing adjustment to maintain 27:73 revenue recovery.

Illustrative Effect of the 27% / 73% Split

In the explanation above, the term L_i (i.e. the Locational Charge at point *i*) has already taken into account the effect of the 27/73% split in revenue recovery between generation and demand. Hence, this split does not have an effect on cost-reflectivity.

Taking the simple, illustrative example presented in Figure 1 of the main text one step further to include this split, the effect is shown below:



*Note: in practice DG will always get paid demand charges, as they are set to a de-minimus level of 0 £/kW

This shows quite simply that the embedded benefit in this case remains at twice the value of the residual (i.e. £10 in this example). Therefore the split in revenue recovery does not have an effect on the cost-reflectivity of the charging signal.