

Response to the Ofgem open letter: Charging arrangements for embedded generation

ENGIE UK

ENGIE, formerly known as GDF SUEZ, is a global energy company operating in three key sectors of power, natural gas and energy services. The company puts responsible growth at the heart of all its businesses in order to address major energy and environmental challenges: responding to the demand for energy, ensuring security of supply, combating climate change and making optimum use of resources.

ENGIE is present in 70 countries worldwide and has expertise in four key sectors: independent power generation, liquefied natural gas, renewable energy and energy efficiency services.

In the UK, ENGIE has interests in a number of activities across the energy value chain, from gas exploration and production through to services. In total, ENGIE employs approximately 17,000 people throughout the UK across all of its businesses. In generation, ENGIE is one of the country's largest independent power producers, with interests in 4,025 MW of plant. This comprises a mixed portfolio of generation assets that include gas, CHP, wind and the UK's foremost pumped storage facility. The portfolio includes a retail business supplying electricity and gas to the Industrial and Commercial sector, and the company continues to develop its renewables business in the UK.

ENGIE is also the UK's leading district energy company. We design, build, finance and operate district heating schemes on long term concession agreements. ENGIE's high profile district heating schemes include the Queen Elizabeth II Olympic Park, Southampton District heating scheme, Whitehall District Heating scheme, Leicester District Heating Scheme and Birmingham District Heating Scheme.

ENGIE welcomes the opportunity to respond to the Ofgem open letter and supports the approach and principle conclusions that Ofgem presents.

Executive summary

- The differential benefit of connecting at the distribution level as opposed to the transmission level is of the order of a few pounds per kW. The current residual transmission charge benefit of £45/kW, coupled with future projected increases, is causing a significant effect on the ability of new and existing transmission connected generation to remain financially viable.
- This unintended windfall is an economic distortion that has destabilised a number of market areas. In particular, it has resulted in lower clearing prices in the capacity market auctions, reduced the value of peak energy in the traded energy markets, and enabled embedded generation to undercut transmission connected generation in the ancillary services market.
- The current regime results in tariffs inconsistent with the true value brought to the system by embedded generation - for example, avoided transmission costs. The commercial incentives created lead to an unsustainable cycle of increasing embedded generation and increasing benefits. In the medium and longer term this will lead to a substantial increase in customer costs and further security of supply concerns as transmission connected generation is forced to either withdraw from these areas (and potentially close) or rely on support from the System Operator to remain operational. It is important to rapidly establish a level playing field between all classes of generation so that effective competition develops and provides the lowest cost outcome to consumers.
- In seeking the lowest cost outcome, any review of charging arrangements for embedded benefits should recognise CHP and other embedded plant that genuinely help avoid transmission costs e.g. high load factor plant. Arrangements for such plant should not be negatively impacted by any review. ENGIE would be willing to engage with relevant parties to seek an approach to achieve this.
- We are opposed to any “grandfathering arrangements”. The charging arrangements are, and have consistently been, subject to change. The Ofgem-led Transmit project clearly indicated to the industry that all charging arrangements could be changed to reflect developments on the system. Parties entering into auctions, or other commercial arrangements, would have been able to take account of potential changes in any commercial arrangements.
- We concur with Ofgem that the current CUSC process is appropriate for reforming the netting element of embedded benefits. Whilst there will be challenges in the months ahead this is the only process (short of primary legislation) that will deliver the reform of the embedded benefit netting regime and ensure security of supply in the near term.
- The outlook for security of supply will be improved by the removal of the embedded netting arrangements. Transmission connected generation can potentially close in a matter of months whilst much of the embedded capacity contracted under the capacity market has yet to begin construction. Levelling the playing field by addressing this issue will likely result in life extensions being available to existing transmission connected assets that would otherwise close.
- We believe that, as a starting point, the removal of the residual element of the netting embedded benefit will enhance the ability of transmission connected generation to compete with distributed generation on a more equal footing. This will remove a major distortion to current arrangements.
- Looking forward, other aspects also require reform. This includes the BSUoS charging arrangements and what is effectively double energy payments for non BM STOR. Reform is also required for the period over which the residual cost of the transmission system is collected, and moving from collection on a net basis to a gross basis.

ENGIE response to charging arrangements for embedded generation**I) Transmission Charging Arrangements****Background**

- 1) NETA (and subsequently BETTA) was designed to deliver a set of trading arrangements in which transmission connected generation and distribution connected Balancing Mechanism generation (BM generation) could compete for the delivery of energy and balancing services on an equal footing. The arrangements did not explicitly consider the treatment of small distribution connected generation (non-BM generation) or demand side services as these provided only a small volume of energy and services.
- 2) Distribution connected generation subsequently identified that an opportunity existed to receive income from suppliers through the “netting” arrangement. This was an unintended consequence of the NETA changes. The cost of this “netting” is funded by distribution connected demand customers whose demand charges are based on their gross metering over the TRIAD periods. The demand charges levied by National Grid on suppliers are, however, based on net metering where they offtake power from the transmission system at the Grid Supply Points (GSP). The embedded benefit arises where embedded generators generate in the TRIADs and reduce net demand offtake creating a money surplus for the supplier. The supplier then shares this benefit with the embedded generator with the embedded generator receiving the bulk of the surplus.
- 3) Since the embedded “netting” benefit is only available to the distribution connected generation that runs over the TRIAD periods, a significant volume of distribution connected generation operates over this duration. Since the TRIADs are only known after the event, embedded generators generate in more than the three TRIAD periods in order to ‘hit’ the TRIADs with the value of the embedded benefit of such a size that this generation is willing to operate at a loss. At current tariff levels, the rewards of running over these periods for distribution connected generation far outweigh the income available to transmission connected generation for producing the same volume of energy in the same time periods. The outcome of this incentivised behaviour is a reduction in energy demand and impacts on traded energy prices in these peak periods.
- 4) Over recent years there has been a significant increase in the embedded (or netting) benefit of connecting to the distribution system and the charging arrangements no longer reflect the structure of the system. This has resulted in the anomalies where the charging regime determines investment rather than economic efficiency. Because of this, the majority of new generation is likely to connect at the distribution level. Existing transmission connected generation is no longer able to compete effectively against heavily “subsidised” demand connected generation for the provision of peaking energy or services.
- 5) The key defect that must be addressed in the current arrangements is this embedded netting benefit. The immediate removal of this netting benefit will lead to a reduction in consumer costs in all timescales and provide a more sustainable energy mix going forward. In a complex and rapidly changing environment the persistence of this distorted investment signal is highly damaging. This change enables the developers and owners of generation (of either class) to compete on the same basis for the provision of energy and balancing services and, ultimately, deliver an economically efficient outcome for consumers.

Change process

- 6) We concur with Ofgem that the current CUSC process is appropriate for reforming the netting element of embedded benefits. Whilst there have been calls for an SCR or a more holistic review, the delay in implementing change would simply result in a continuation of the existing regime at an ever increasing level with implications for the potential further loss of transmission connected generation.

Grandfathering of the embedded “netting” benefit

- 7) The charging arrangements are, and have consistently been, subject to change. The Ofgem-led Transmit project clearly indicated to the industry that all charging arrangements could be changed. Parties entering into auctions, or other commercial arrangements, would have been able to take account of potential changes in any commercial arrangements. We believe that since there is no evidence to support the proposed value of benefits, grandfathering (or delaying change) will do little to correct the market distortion that the current level of embedded benefits creates. It would also disadvantage new embedded generators who would not be treated on the same basis.

Impact on transmission connected generation and market integrity

- 8) Transmission connected generation relies on the traded market, capacity market and balancing services market to cover costs. For an existing coal plant to be viable (without making any return) it would typically require at least £45/kW from these revenue sources. Achieving these levels is particularly challenging given forward spreads. It therefore provides a good case study on the rationale for removing the embedded netting benefit.
- 9) Any shortfall in the required revenue from the traded market and from balancing services will need to come from the Capacity Market. Embedded plant has an unwarranted £45/kW head start and can comfortably undercut coal plant, pushing coal out of the market. It is difficult to understand how an efficient economic outcome can be achieved for the value of capacity, energy and services when there is such a large distortion to competition.

Effect of the removal of the current embedded netting arrangements on TNUoS revenues

- 10) In the short term there is likely to be no significant effect on the TNUoS allowable revenue as this is stable over a price control period. In the medium and long term the required size of the transmission system will determine the level of TO investment required and, ultimately, the cost to the consumer.
- 11) Embedded and transmission connected generation has the same effect on the transmission system when located at the same grid supply point. For example, 1,000 MW of generation located in Scotland will drive the same reinforcement need irrespective of whether it is embedded or transmission connected. The main difference between the two classes of generation will be the locational tariff that is applied.
- 12) Transmission connected generation has a relatively strong locational tariff with high price signals in the North of the UK and low or negative prices in Southern England near major demand centres. This has been a factor in the closure of some transmission connected power stations. Embedded generation sees a large negative price signal at all locations - the signal has only a small locational element applied (driven principally by the large demand zones used in its calculation).
- 13) Given the difference in locational price signals, from a TNUoS perspective, embedded generation (weak locational signal) is likely to result in a larger transmission system compared to transmission connected

generation (strong locational signal). Thus a higher level of embedded generation is likely to drive a larger, more costly transmission system compared to transmission connected generation.

Security of Supply

- 14) ENGIE believes that controllable generation (whether embedded or transmission connected) is important to ensure secure energy supplies for all consumers. The current TRIAD regime that encourages embedded generation to deliver only energy at times of the highest transmission demand. It provides little or no incentive to deliver energy at other times. Whilst system stress events are rare, they have historically occurred away from the system peak and often outside of the TRIAD season. Recent events (for example, on 14th and 15th September 2016) showed the importance of transmission connected generation to the system. The availability of significant reserves of transmission connected energy provided the necessary supply to prevent a crisis. Without reform of the embedded benefit system it is likely that this type of transmission connected plant will withdraw early from both the energy and balancing services market.
- 15) It is significantly more economic to extend the life of existing assets rather than build new generation. The consequence of the continuation of embedded benefits would be a further loss of transmission connected generation that will need to be replaced by embedded generation, driving a further increase in the TNUoS benefit available to this class of generation.

II) Specific cost reflective comments

Netting arrangements and behind the meter

- 16) Appendix A provides details of a model used in the CMP 264/265 working groups to provide an understanding of the money flows, costs and funding arrangements relating to embedded and behind the meter generation. Whilst the cost of the two arrangements could be considered similar, supplier netting results in an extra cost to all consumers whilst behind the meter generation results in a reduced cost for the meter owner (but ultimately increased cost for all other consumers given that TNUoS is a zero sum game). We believe that urgent action is required to address the netting arrangement where the bulk of the current defect lies. Behind the meter generation also needs to be addressed by a deeper look at how the residual cost of the transmission system is recovered to ensure that all customers pay a fair share of the costs.

Effect on the transmission system of distribution compared with transmission connected generation

- 17) Appendix B provides evidence of the effect on the transmission system of embedded generation and a similar amount of transmission connected generation when connected at the same point. This shows that transmission connected generation and distribution connected generation have the same effect on the transmission system when connected at the same GSP. This demonstrates that the netting benefit, far from being cost reflective, is simply an additional cost to transmission customers.

Locational signal

- 18) Appendix C provides evidence of the locational effect on the size of the transmission system of connecting (transmission or distribution) generation in response to a locational signal or instead evenly spread across the distribution zones. The key message is that the incremental size of transmission system will be around 6% larger if 5,000 MW of new generation is connected evenly over transmission, instead of responding to a locational signal. It is thus appropriate that all generation (embedded or transmission) receives a locational signal.

Embedded substation benefit

- 19) Appendix D details the embedded substation benefit that we believe is appropriate to calculate and pay to embedded generation. It reflects the local cost saving in GSP infrastructure associated with connecting generation via an existing demand circuit and potentially avoided reinforcement cost.

Residual cost of the transmission system

- 20) We do not believe that distribution connected generation should be subject to the residual cost of the transmission system but it should be subject to the incremental cost of the locational decision. Thus we believe it should be subject to a locational tariff plus an embedded substation benefit as described above.

Transmission and distribution connections

- 21) Transmission connected generation owns and operates all connection assets to allow export onto the 400kV transmission system. Distribution connected generation is treated in an identical way funding the distribution companies cost associated with reinforcement of the distribution system to allow embedded generation to connect to the transmission system. We do not believe that there is any fundamental difference in treatment of this element of charging regime. Additional DUoS benefits available to distribution connected generation (on a standard methodology basis) based on a cost reflective methodology seem appropriate.

Collecting the residual cost of the transmission system

- 22) The current transmission charges for demand are collected on a net basis over the three periods of highest demand (the TRIADS). This provides a strong signal to reduce demand during these periods, and also to reduce charges faced by individual demand users. The method used to collect the residual cost of the transmission system is important for many users and it has the potential to affect demand behaviour. We believe that a more measured review of this area is needed to ensure that the impact of a potential solution can be considered. Spreading the residual collection too wide will have negative effects on development and operation of new and existing storage, whilst collecting it over too few hours has the potential to significantly impact the operation of the energy market. One option (detailed below) would be to collect it over a fixed period. We consider a full commoditisation of this residual would have significant implications for storage users as they would effectively pay twice for the same connection.
- 23) The location component of TNUoS reflects the incremental cost of connection at a location, and a residual component that collects the balance of allowable costs. The locational component represents around 10%-15% of the cost of the transmission system (see Appendix C) with the residual cost representing around 90% of the cost. Approximately 10% to 15% of the cost of the transmission system should be recovered over demand peaks using the existing TRIAD methodology by adding an appropriate fixed element. This should be recovered from gross demand importing during the TRIAD periods. The balance, around 90% of demand TNUoS, could be recovered across gross demand based over a fixed time period ranging from several hundred to several thousand hours.
- 24) This methodology would continue to provide an appropriate incentive to reduce the size of the transmission system but ensure that all users pay a fair share of the cost. The current arrangements, in which all costs are recovered over the TRIADS, allow some customers to avoid paying for a transmission system that they benefit from for the remainder of the year. Industry and National Grid needs to raise a CUSC modification to address the current TRIAD to keep some element of this based on peak capacity but recover the residual element over a longer time period or have it commoditised. ENGIE believes developments should take place over the next 12 months.

III) BSUoS charging arrangements

25) ENGIE agrees with Ofgem that a review of BSUoS charging arrangements is not as urgent as addressing the TNUoS situation. However, any review carried out should be holistic, covering the following areas:

- a) Ensuring that embedded generation pays an appropriate share of the costs of balancing the system;
- b) Better targeting of when balancing costs are applied. For example, plant is warmed overnight in order to provide response for the evening peak. Those operating in off-peak periods are charged for the warming costs despite it being needed for the peak periods;
- c) A more general review of to whom BSUoS costs are allocated.

IV) Spill energy payment

Embedded balancing services energy benefit

26) ENGIE has identified a double energy payment for Non-BM STOR. We do not believe that National Grid takes account of this when procuring or dispatching Non-BM STOR. This creates a further embedded benefit which also needs to be addressed. The double payment is described in the following paragraphs.

27) Non-BM STOR receives an energy payment from National Grid based on the energy delivered and metered. The Non-BM STOR volume appears in the supplier's energy account and drives the supplier long. The supplier pays the Non-BM STOR provider the cashout price it receives for the spilled energy, less a fee (approximately 10%).

28) For example, the utilisation fee for Non-BM STOR was on average £90/MWh between November 2015 and July 2016. The cashout price received by the supplier when the Non-BM STOR was delivered in this period was £87/MWh. This spill payment can be shared with the Non-BM STOR provider. The overall cost to the end consumer is thus £177/MWh, although this overall amount is not taken into account when dispatching Non-BM STOR.

29) When National Grid assesses STOR tenders it is assumed that BM and Non-BM energy price is comparable but this is not the case. BM STOR cannot receive the cashout spill payment as the volume is treated as a Bid Offer Acceptance (BOA). The embedded Non-BM STOR provider does receive this spill payment which is applicable to all energy delivered from Non-BM balancing services providers.

30) National Grid should review its procurement and despatch process in combination with the C16 licence condition and develop changes to commercial arrangements to meet licence obligations in a timely fashion.

V) Flexibility

31) In changing the charging arrangements, it is important to ensure that storage is not charged twice for the same connection.

32) There are various ways that the market rewards flexibility, and provision of capacity is distinct from this. As the amount of flexible generation increases, it is important to only reward generation in the capacity mechanism that has the capability to deliver energy for a period of time that better aligns with the duration of a system stress event. ENGIE has raised a capacity mechanism rule change to address this.

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Technical Appendices Executive Summary

The analysis in the appendices below was presented to support CUSC working group discussions on this subject.

Appendix A addresses the money flows for different type of generation/reduction in demand, including transmission-connected generation, embedded generation sold to a supplier, on-site generation and demand side reduction. The information demonstrates that although the flows on the transmission system associated with a particular action are the same (in this example a reduction of 100MW) the TNUoS costs to the end consumer are different. For transmission-connected generation there is no additional cost to the consumer. For embedded generation all consumers see an increased cost. For on-site generation and Demand Side Response (DSR), the host demand sees a reduced cost but all other consumers see an increase in costs.

Appendix B is a load flow analysis of the effect on the transmission system of distribution connected generation. It uses the current version of National Grid's transport model. This shows that identical load flows result from connecting generation at either the transmission or the distribution level. The increase or reduction in the size of the transmission system is only affected by the location of Grid Supply Point (GSP) relative to other demand and generation connections and the network parameters. Distribution and transmission connected generation have the same effect on system flows and hence the size of the transmission system.

Appendix C illustrates the effect of connecting multiple generators on the transmission system with an equal level of MW in each generation zone compared with a pro-rata increase in line with the generation locational tariff. This shows that without a locational tariff the size of the transmission system (MW per km) is around 6% larger than it would be with the locational tariff. The result of applying the current embedded benefit across all embedded generators (with negligible locational signal) is likely to result in a larger, more costly transmission system than would otherwise be the case.

Appendix D demonstrates that if the generator connection saving (£1.44/kW/year) is added to the cost estimated by National Grid of avoided demand connection (£1.62/kW¹) the combined embedded benefit is around £3-4/kW/year in value. It suggests adding a new charge to the substation cost relating to connection generation via a demand connection. The embedded substation benefit of £3-4/kW would be calculated by National Grid using the same methodology as substation cost CUSC 14.15.119 and would avoid substation costs resulting from generation connecting via a demand circuit.

Appendix E is a high level overview of the DCLF model used in this analysis as well as the CUSC link to obtain the model.

Appendix F contains consumer impacts and further thoughts on Green Frog and UK Power Reserve proposals.

¹ Embedded Benefit Review | National Grid 15th January 14, section 4.6.

Appendix A

Impact of embedded generation, onsite generation and demand side response on customer costs

This note details the incremental impact on transmission costs (as collected by suppliers and National Grid) resulting from the connection of 100MW of various types of distributed generation. Diagram 1 below shows the system used for the presentation with the main transmission system demand, generation and embedded generation represented by F_m , T_m and E_m respectively.

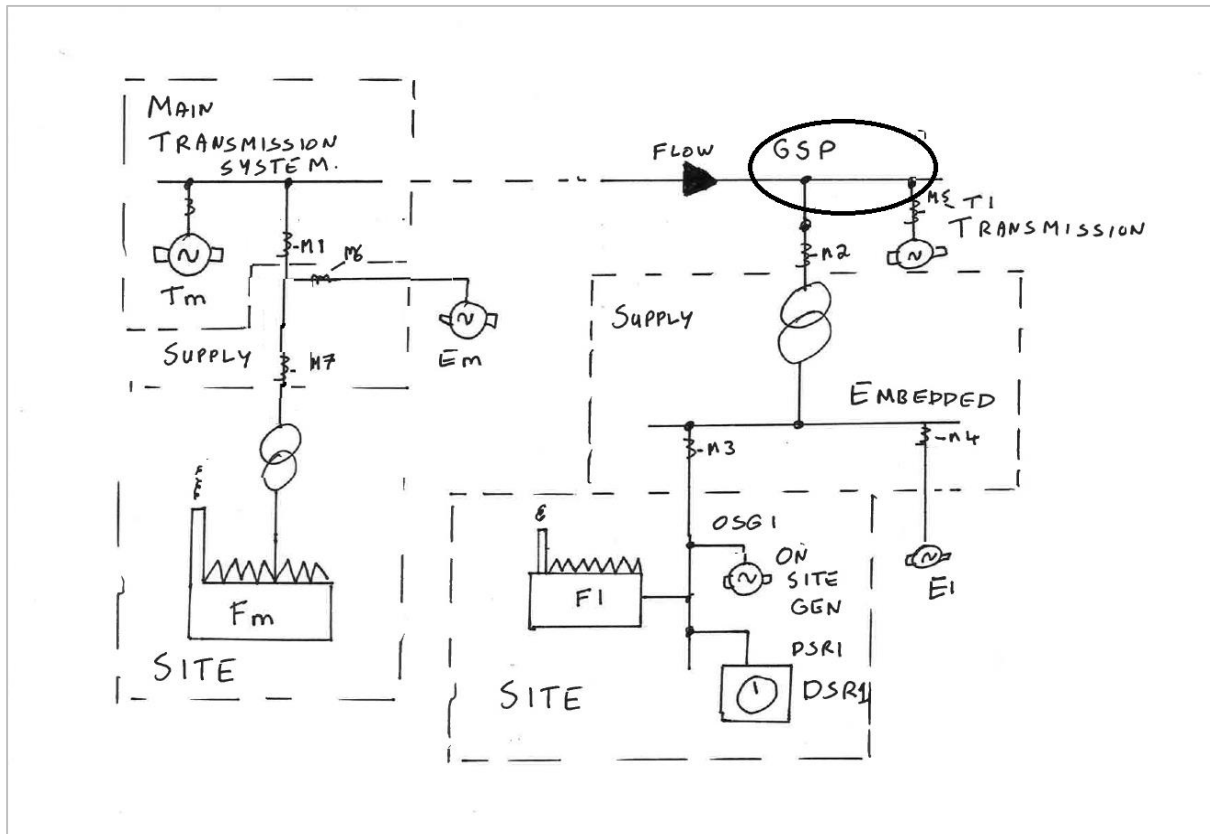


Diagram 1: main transmission system demand, generation and embedded generation

A small node (GSP) on the system was then examined that contains a 1000MW of demand ($F1$). 100MW of generation/demand reduction is placed at four locations below the GSP to replicate supplier connected embedded generation ($E1$), on site generation ($OSG1$), demand side response ($DSR1$) and transmission connected generation ($T1$) at the same GSP.

The MW assumptions for each load/generator are shown in Table 1 below. Meters are allocated as required but principally at boundaries to the supplier zones. The numbers used are representative of the actual demand/supply and costs at peak.

	Base assumptions		Base	Transmission	Embedded	DSR	OSG
Demand	Demand	Fm (M7)	56000	56000	56000	56000	56000
		F1	1000	1000	1000	1000	1000
Generation	Transmission	Tm (slack Bus)	-50100	-50000	-50000	-50000	-50000
		T1 (M5)	0	-100			
	Embedded	Em (M6)	-6900	-6900	-6900	-6900	-6900
		E1 (M4)			-100		
	DSR	DSR1				-100	
	On site gen	OSG1					-100
	=Fixed	Changes					

Table 1: MW assumptions for each load/generator

The output from the model for the four scenarios is shown in Table 2 below based on increments of 100MW:

			Base	Transmission	Embedded	DSR	OSG
Transmission Demand (M1 + M2)		MW	50100	50100	50000	50000	50000
Supplier Demand (M7 + M2)		MW	57000	57000	57000	56900	56900
Transmission Cost		£m	2275	2275	2275	2275	2275
Rate		£/kw	45.41	45.41	45.50	45.50	45.50
			Base	Transmission	Embedded	DSR	OSG
Flow (MW)			1000	900	900	900	900
Transmission Customer Cost(Fm+F1)		£m	2588.32	2588.32	2593.50	2588.95	2588.95
F1 cost		£m	45.41	45.41	45.50	40.95	40.95
E1+Em Cost		£m	-313.32	-313.32	-318.50	-313.95	-313.95
Delta Transmission Cost (100MW)		£m	NA	0.00	5.18	0.63	0.63
Delta F1 Cost		£m	NA	0.00	0.09	-4.46	-4.46
DSR/onsite payment [50/90%] of benefit		£m				2.23	4.01
Customer cost + DSR/onsite payment		£m	2588.32	2588.32	2593.50	2591.18	2592.96
Delta cost		£m		0.00	5.18	2.86	4.64

Table 2: Output from modelling

The key points from this analysis are:

1. For all four options the flows on the transmission are the same at 900 MW import. So the effect on the transmission system of connecting embedded, on site generating, DSR or transmission connected generation via the same GSP is the same.
2. Funding for supplier embedded benefits is collected from the difference between the supplier and the transmission demand changing base multiplied by rate (TNUoS tariff); this funding is shared across all demand customers in equal share.
3. The incremental transmission cost to consumers resulting from connecting additional 100MW of embedded generation via the supply embedded route is £5.18m. This results from a reduction in the transmission demand charging base (creating a higher tariff) that is then collected over the larger supplier charging base. This is more than £4.55m as the higher tariff is collected over all embedded generation and not just the additional 100MW. This creates an additional £0.63m of cost.
4. The incremental transmission cost to consumers resulting from connecting additional on Site/DSR is £0.63m. The tariff is the same as the supplier embedded generation but the supplier charging base is 100MW smaller. The reduction in the cost borne by the demand that hosts the DSR/OSG can be used to pay for DSR [50% assumption] or own generation or a private wire to an external provider [90% assumption]. The money comes from the demand host as opposed to all customers.

5. If the additional payment made by the demand host to (DSR/OSG) is included as a transmission cost then the cost of onsite generation approaches the cost of the supplier embedded generation option.
6. The lowest incremental transmission cost to consumers is 100 MW of transmission connected generation at the GSP. This results in no change to costs faced by consumers and does not change the supplier or the transmission demand charging base.
7. On site generation and DSR are different in character to supply embedded generation. With onsite generation/DSR the lower supplier transmission cost was seen directly by the demand host. The benefit could be used to reduce demands as long as the cost of reduction does not exceed the benefit of reduction. With supply embedded generation there is an increased transmission cost that is seen by all consumers without exception.

Appendix B

DC Load flow analysis of effect on the transmission system of distribution connected generation

Background

The 2016/17 National Grid Transport and Tariff Model was used to examine the difference in network flows and the size of the transmission system of connecting 450 MW of generation via demand (embedded) or transmission at Norwich 400KV substation (as shown in the diagram and table below). Norwich substation was chosen as it includes both demand and generation at the same Grid Supply Point.

Methodology

The 2016/17 Transport and Tariff Model was set up using tariff generation and demand data but forced to run an identical load flow by re-categorising all generation as CCGT (this allows all generation to appear in the Peak and Year round load flows). This simplifies the analysis as only one generator scaling factor needs to be dealt with.

Generation was scaled to meet demand as is required for a load flow model (approximately 72% scaling factor) and the load flow run to determine the size (MW per km) of the network and the power flows on all transmission circuits (Base scenario). The MW per km represents the length of 400 kV transmission lines (cables and lower voltage lines are converted to 400 kV equivalents) multiplied by the power flow. It does not include historic costs, the cost of non-locational items (e.g. substations, transformers) or other RIIO costs, such as SO costs. 450 MW of transmission connected generation was added at one substation, Norwich 400kV (NORM40), and the load flow was re-run (Option A). This was repeated by simulating the connection of 450 MW of embedded generation by reducing demand at the Norwich 400kV substation by 450 MW (Option B). As expected the power flows on all transmission system circuits produced identical results for Option A and B. These power flows are shown in Diagram 2 below:

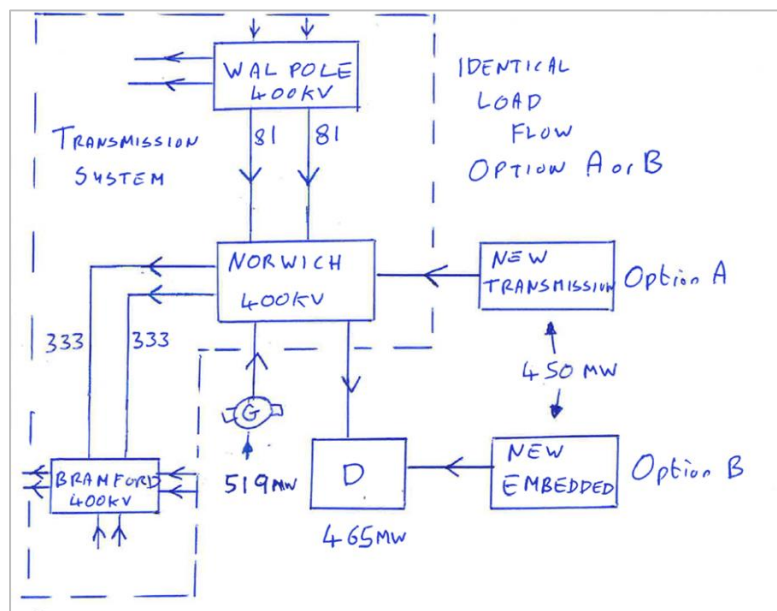


Diagram 2: Power flows

Overall the size of the transmission system (MW per km) reduced by 0.56% as a result of the connection of 450MW of embedded/transmission generation as can be seen in the table below.

Scenario NG 16/17 tariff all plant type set to CCGT force one load flow (Year round)	Bus Name	Demand MW	Generation MW	Toatal load flow MWkm	% Network size change
Norwich 400 kV substation base load flow	NORM40	465	519	7,751,081	0.00%
Option A transmission + 450 MW generation	NORM40	465	969	7,707,548	-0.56%
Option B embeded generation - 450 MW demand lower	NORM40	15	519	7,707,549	-0.56%

Table 3: Impact of size of transmission system

Key Observations:

1. The network flows on the transmission system as a result of connecting a similar volume of transmission generation or embedded generation at the same point are identical.
2. The change in the size of the transmission system as a result of connecting embedded or transmissions generation at the same Grid Supply point is identical. The increase or reduction in the size of the transmission system is only affected by the location of the GSP relative to other demand and generation connections and the network parameters.

Appendix C

Effect on the size (MW per km) of transmission system of connecting generation (distribution or transmission) evenly or according to a locational signal

Background

Following on from the Appendix B analysis that looked at the effect of connecting embedded/transmission generation at the same Grid Supply Point, further analysis was undertaken to establish the effect on the size of the network of connecting generation evenly across the network (i.e. no locational signal) or in proportion to a locational signal.

As previously noted the MW per km represents the length of 400 kV transmission lines (cables and lower voltage lines are converted to 400 kV equivalents) multiplied by the power flow. It does not include historic costs, the cost of non-locational items (e.g. substations, transformers) or other RIIO costs e.g. SO costs.

Methodology

The 2016/17 Transport and Tariff Model was set up using tariff generation and demand data, and the model used without modification. The initial run established the size of the network (Peak plus Year round MW per km) as used in the tariff calculation. Scenarios 1 to 6 were then performed to establish the effect on the size of the transmission system resulting from connecting 5,000MW of conventional (CCGT type) generation in various generation tariff zones. Scenarios 7 to 9 were then performed that added different amounts of generation to each of the generation tariff zones based on even distribution (7), in proportion to the generation locational tariff (8) or the reverse generation locational tariff (9). The actual MW added to each zone are shown in Table 4 and 5 below:

Transport and tariff model 16/17 with additional MW showing change in size of			Peak MWkm	Year Round	Peak + Year Round	Annuitized cost **	% from base
Scenario	Zone	Change applied to zone	MWkm	MWkm	MWkm	£m	%
0	Base case tariff model		4,907,755	4,457,111	9,364,866	£224.87	0.00%
1	North Scotland (z1)	+5000 MW generation	7,677,102	5,453,463	13,130,565	£315.29	40.21%
2	Stirlingshire and Fife (z9)	+5000 MW generation	5,615,063	5,545,066	11,160,129	£267.98	19.17%
3	West Devon and Cornwall (Z27)	+5000 MW generation	5,042,423	5,131,648	10,174,071	£244.30	8.64%
4	West Midlands (z13-z18)	+5000 MW generation	4,857,261	4,751,375	9,608,636	£230.72	2.60%
5	Mid Wales and The Midlands (z18)	+5000 MW generation	4,705,604	4,567,725	9,273,329	£222.67	-0.98%
6	Central London (Z23)	+5000 MW generation	4,538,888	4,200,420	8,739,308	£209.85	-6.68%
7	All zones	185.1MW all zones *	4,702,668	5,601,791	10,304,459	£247.43	10.03%
8	All Zones	locational see table*	4,460,641	5,245,271	9,705,912	£233.06	3.64%
9	All Zones	Reverse locational*	5,179,169	5,943,590	11,122,759	£267.08	18.77%
** Expansion constant £13.34/MWkm and Security Factor 1.8			* see table of MW per zone below				

Table of MW applied to each zone		Even all zones	Locational	Reverse locational
Name	Zone	MW	MW	MW
North Scotland	1	185.2	56.3	342.6
East Aberdeenshire	2	185.2	123.2	260.8
Western Highlands	3	185.2	88.6	303.2
Skye and Lochalsh	4	185.2	120.6	264.1
Eastern Grampian and Tayside	5	185.2	103.3	285.2
Central Grampian	6	185.2	63.6	333.7
Argyll	7	185.2	0.0	411.4
The Trossachs	8	185.2	119.2	265.8
Stirlingshire and Fife	9	185.2	189.4	180.1
South West Scotland	10	185.2	144.0	235.5
Lothian and Borders	11	185.2	159.0	217.2
Solway and Cheviot	12	185.2	198.9	168.5
North East England	13	185.2	225.1	136.4
North Lancashire and The Lakes	14	185.2	197.9	169.6
South Lancashire, Yorkshire and Humber	15	185.2	191.7	177.2
North Midlands and North Wales	16	185.2	206.9	158.7
South Lincolnshire and North Norfolk	17	185.2	225.8	135.6
Mid Wales and The Midlands	18	185.2	237.1	121.7
Anglesey and Snowdon	19	185.2	186.1	184.1
Pembrokeshire	20	185.2	180.5	190.9
South Wales & Gloucester	21	185.2	216.2	147.2
Cotswold	22	185.2	254.5	100.5
Central London	23	185.2	336.8	0.0
Essex and Kent	24	185.2	266.4	86.0
Oxfordshire, Surrey and Sussex	25	185.2	293.1	53.3
Somerset and Wessex	26	185.2	307.7	35.6
West Devon and Cornwall	27	185.2	308.1	35.0
Total		5000.0	5000.0	5000.0

Tables 4 and 5

Key observations

- 1) Locating generation remote from demand centres (e.g. North Scotland) increases the size of the network, whilst connecting generation close to demand centres (Central London) reduces the size of the network.
- 2) The increase in size of the network between generation located evenly over each tariff zone (scenario 7) as opposed to pro-rated to a locational signal (scenario 8) is approximately 6% larger.
- 3) The locational cost of the transmission network (that is, MW per km multiplied by the expansion factor and the security factor) represents approximately 10% of the network cost with the remainder being made up of historic and non-locational items. The non-location related costs are included in the residual.
- 4) There is no difference between the size of the transmission system resulting from connection of distribution or transmission connected generation.

Appendix D

Benefits to Transmission users of generation connecting via the distribution system

Diagram 3 below illustrates typical funding arrangements for connection of transmission and distribution connected generation.

Transmission connected generators typically own and fund all equipment (1) including the 400kV switch. A skeletal 400 kV bay (6) is typically provided by the TO (included in TNUoS charges) to connect to the transmission system at £10/kW for a 500 MW connection. As this connection is funded by TNUoS it is not directly paid for by the generator but funded by all customers.

Distribution connected generators face similar charges. They pay for their own works (2), fund sole user works (3), and a share of reinforcement (4), (5). In general, no works are required to the distribution connection (7) to the 400 kV system except in the case of exporting GSPs connection when funding is typically included in TNUoS.

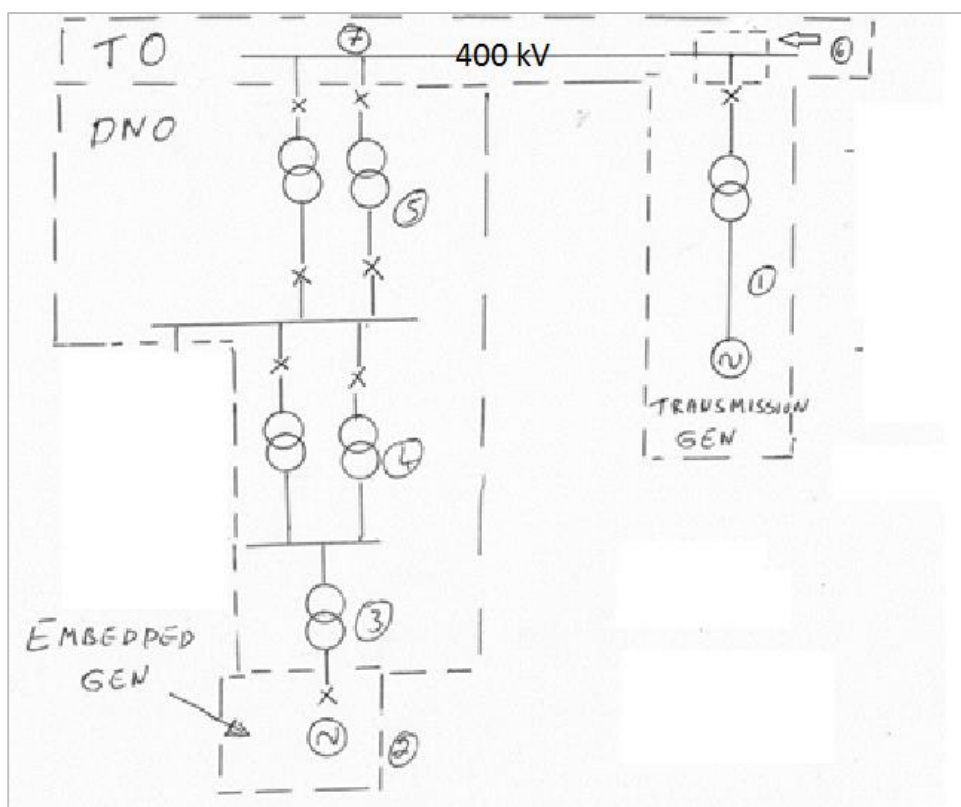


Diagram 3: typical funding arrangements for connection of transmission and distribution connected generation

Key	Typical funding arrangements for connections
1	Transmission generator owner
6	TO owned securitised by Transmission generator
2	Embedded generator owned
3	Sole works funded by embedded generator
4	Reinforcement funded by embedded generator
5	Reinforcement funded by embedded generator
7	Exporting GSP's no embedded generator funding

RIIO sets the baseline revenue than can be collected via TNUoS on an annual basis. This includes allowances for capital projects as well as some volume related drivers. For generator connections for 2016/17, an allowance of £220m for 3553 MW of connection has been made. This covers all generator connection work. Some of this is classified as connection (sole user works) and some related to shared works such as the skeletal bay described above. Different years have different costs depending on the business plan with an average of £30/kW/new connection.

Part A: Baseline Generation Connections and Allowed Expenditure

6F.5 Table 1 in this condition sets out the baseline forecast of Generation Connections (BGCO) and overhead line (BLOHL) for each Relevant Year in the Price Control Period and the baseline expenditure (BGCE), in 2009/10 prices, associated with those baseline outputs as at 1 April 2013.

Table 1: Baseline Generation Connections and Allowed Expenditure

	Relevant Year							
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
BGCO (MW)	504.0	1597.0	3264.0	3553.0	1540.0	3797.0	5649.5	13819.0
BLOHL (circuit km)	5.4	0.0	0.0	100.0	0.0	70.0	40.0	0.0
BGCE (£m)	130.524	185.228	184.112	220.710	117.364	95.965	42.494	20.662

6F.6 The baseline expenditure set out in Table 1 in this condition has been reflected in:

- (a) the licensee's Opening Base Revenue Allowance, set against the licensee's name in Appendix 1 to Special Condition 3A; and
- (b) GCE values contained in the PCFM Variable Values Table for the Licensee contained in the ET1 Price Control Financial Model as at 1 April 2013.

Table 5 below shows the indicative annual cost (£/kW) for generator connection from 2015/16 to 2020/21 derived from the RIIO data. The average cost is around £2/kw/year.

Indicative Cost		2015/16	2016/17	2017/18	2016/18	2017/19	2018/20
Total Circuit Capital Cost	£m	184.1	220.7	117.4	96.0	42.5	20.7
Capacity	MW	3264	3553	1540	3797	5650	13819
Unit Cost	£/kw	56.41	62.12	76.21	25.27	7.52	1.50
Depreciation	years	45	45	45	45	45	45
Rate	WACC	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%
Annuity	rate	0.053	0.053	0.053	0.053	0.053	0.053
Annual Cost	£/kw/year	2.967	3.268	4.009	1.329	0.396	0.079

Table 5: indicative annual cost for generator connection from 2015/16 to 2020/21 from RIIO data

If the generator connection saving is added to the cost estimated by National Grid of avoided demand connection (£1.62/kW) the combined embedded benefit is around £3-4/kw/year. Embedded generation connecting via exporting GSPs does not result in a demand infrastructure saving but instead causes a cost, so this saving should be removed from sites exporting via an exporting GSP. The avoided demand connection cost is also possibly overstated depending on the nature of generation. High load factor generation would lead to reduced infrastructure at the GSP but low load factor or intermittent generation is unlikely to lead to reduced demand GSP infrastructure. Therefore, the benefit may be overstated for this class of generation.

We suggest the Embedded Substation benefit be calculated as per other substation costs and be the “Avoided cost of connection generation via a demand circuit”. National Grid would set the initial value and would thereafter update it in line with RPI with a full review after each price control. An example table is shown below.

14.15.118 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

Substation Rating (b)	Connection Type (c)	Substation Voltage (a)		
		132kV	275kV	400kV
<1320MW	No redundancy	0.133	0.081	0.065
<1320MW	Redundancy	0.301	0.192	0.155
>=1320MW	No redundancy	n/a	0.257	0.208
>=1320MW	Redundancy	n/a	0.417	0.336
Embedded substation benefit		- 3.500		

A total of eighteen NGET schemes were assessed from their RIIO-T1 price control submission and the spread of infrastructure costs can be seen in Figure 10 below.

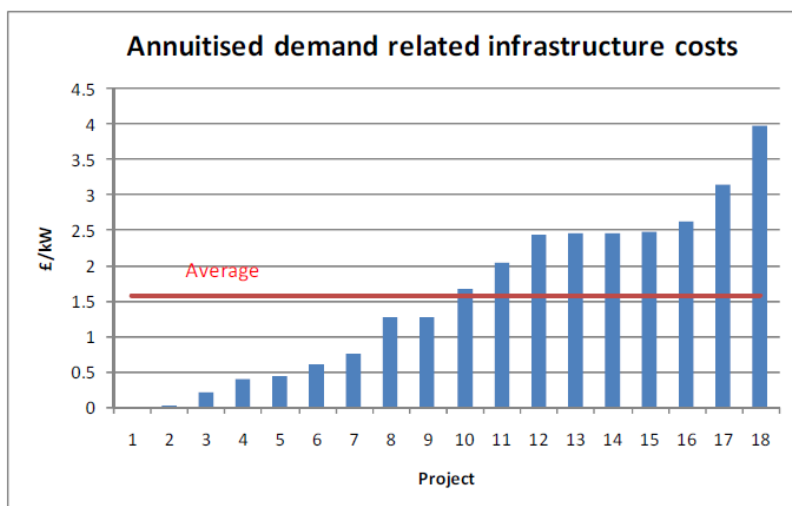


Figure 10

The average annuitized cost was determined as £1.58/kW in 2012/13 prices (£1.62 in 2013/14 prices). This is comparable with previous analysis in 2009/10 where the equivalent price was £1.47/kW.