Response to Consultation on Connection Policy Framework in Northern Ireland

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Precepts and Assumption on overall Network in a Power System

Introduction:

An assessment of options for change is critically dependent on the assumptions made on how the Network is expected to develop in the future.

At it's simplest, if electrification of heat and transport requires the uprating of upstream network in the near future anyway, then there would be little point in trying to allocate costs for this work to earlier connectees.

Assumptions and precepts:

1. Network costs are driven by Peak Demand or Peak Generation, not by kWh throughput – the volume of kWh carried by the network does not impact on the cost of the network.

2. Correct Connection Pricing is beneficial as:
   - Correct Price of connection provides economic signal for optimal use of Network
   - Costs are allocated equitably
   - Assets already in place are fully utilised

3. Local Domestic PV generation for own consumption, and for export, is incorrectly priced to the extent that it exceeds the energy cost of a kWh from a large Wind/Solar farm

   Consequently, if the customer is being paid for saving amounts above the energy cost of a kWh, this mean that these extra costs, which are composed mainly of allocations of Fixed Costs/Taxes/Levies, have now to be paid by the remaining customers.

4. Assuming large volumes of Offshore Wind as well as large On Shore PV/Wind, (to meet 80% CCA target) the Network will have to be substantially reinforced so that the energy generated can be absorbed by the load when wind/solar is available.

   Energy not absorbed by load will either be spilled or, to the extent generation is needed when wind/solar unavailable, used in electrolysers to produce gas for Hydrogen fuelled generators.

5. The Variable cost component of a kWh from such large renewable generation will be lower than that of a kWh produced from Domestic PV, and equally CO_2 free.

   However, when imported by a customer from the grid, the kWh cost will include an appropriate share of fixed costs and taxes, which a customer with their own PV will escape, even though they have an equal need for the same network connection and impose similar costs.

6. Costs for Demand connectees should be established in relation to the expected final state of network development.

   The final network configuration can be established by assessing the network structure in 2050 and then assessing what network reinforcements are required to meet this structure.

   Interim investments may be brought forward or pushed back as load/generation progresses, however if the scale of change is very large (as is likely) the timeline and schedule for investment will be independent of load variations and will instead be based on a programme of required work e.g. uprate all 11kV to 20kV

7. Generation may make use of established networks at low costs as the network will be present for demand and it more optimum for society to encourage it's full use.

   However, when generation adds costs because the network needs to be upgraded then the generator should pay whatever additional costs are entailed.

8. V2G Cars will be able to provide standby to individual customers for 2-3 days, and by simply parking their second car in a neighbour's driveway power could also be shared in an emergency.

Based on the above assumptions the answer to the questions raised would be as follows:

Q1. What are the risks ad opportunities of microgrids and what issues do these raise for the connection frameworks in NI?

Microgrids are most suited to the development of networks in areas with limited or no access to network connections (e.g. undeveloped areas in Africa) or where the continuity is exceedingly poor with outages of several weeks (e.g. parts of USA). Many definitions of Microgrid (see CIRED reports).

However, all current Networks originally evolved from isolated networks which were connected to isolated generators, but due to economies of scale and the continuity/security benefits of linking networks and the ability to pool generation (so that generator output did not need to coincide with load demand from small number of customers), this led to the development of interconnected generators and network circuits.

The practical difficulties with microgrids are that:

(a) They are complex to operate technically as they may need to operate either in parallel or separately from Grid, so load and generation must be dynamically balanced
(b) Maintenance and operation have safety aspects and require skilled personnel available 24/7

(c) Margins can be very small when the difference in the price of electricity from the Grid or from local generation establishes the margin, and in turn this means that transaction costs are very significant in relation to this small margin e.g. reconciliation of metering etc.
(d) If Regulation requires customer choice of supplier, it is exceedingly difficult and costly to move the customer physically from the microgrid to the local grid network
(e) If customers leave the microgrid, the remaining fixed costs are now spread over a smaller number of customers creating a 'death spiral 'as more customers are ow encourage to leave due to higher prices charged

So the issue is what are the benefits which customers would get from a microgrid over and above what they already get form independent grid connection with/without own generation?

If they receive an export tariff then the only benefit from a microgrid would be if it were higher, and as the microgrid will be in competition with marginal cost from offshore wind this is unlikely, Transaction costs will be high including metering, operations, legal and insurance.

Outage durations and frequency are not long enough to justify microgrids.

These are the risks to the microgrid entity – the risks to other customers are possible cross subsidisation if microgrids escape fixed costs which are then borne by remaining non-microgrid customers, the extra Regulatory burden imposed on the Regulator in policing small individual systems.

A virtual Microgrid as available from Enedis in France overcomes such issues as entry/exit from the microgrid is just by software, and all customers continue to pay DUOS, but with the conciliate of rates between member the responsibility of the Microgrid operator. No technical issues as the microgrid is virtual and based on the existing Network. However, the cost of establishing this facility was extremely high e.g. bespoke Smart Meters required as well as a new Billing system. Uptake has not been high.

Essentially the economics of microgrids in NI would not be dictated by benefits to resilience, or increased renewables, but instead by savings to microgrid members, although in essence this means transferring costs to other customers.

Customers with V2G Electric Vehicles could generate for themselves, and if necessary, share power by simply connecting their car to the neighbour's house – no need for interconnected microgrid– a with widespread V2G each house is it's own microgrid

Practical Examples:

In Australia, Microgrids became popular as they provided a way of establishing private monopolies in apartment blocks, housing estates and industrial estates, where electricity imported at HV Tariffs was then retailed at much higher LV tariffs, but which were still at 10% below local utility tariff (so that customer would not move Supplier).

Such microgrids were only established in new developments so that no further network investment would be required within the microgrid areas – adjoining older developments remained the responsibility of the local DNO.

Microgrid operators were both Retailers and Distributors and largely unregulated in both areas.

Recently the Australian market operator has imposed severe restrictions on any new microgrids being established.

In US two large Microgrids in same city are merging because of the benefit of interconnection, effectively beginning to consolidate and form their own network grid.

US Universities and some military bases have their own microgrids for security and to avoid general Network costs.

Island communities have also used microgrids for resilience, but they tend to be expensive and technically difficult to operate.

Q2 Do you agree with the Guiding Principles?

The features set out on p28 are not actually Guiding Principles!

The first states that the '*Connection Policy Framework will facilitate delivery of Energy Strategy targets*' – how could it be expected to do otherwise?

Second states *'…review will facilitate a just transition… and seek to benefit all NI Customers ensuring connection cost changes are proportionate to customer benefit'.*

But for connection costs change there must be winners and losers, so not all customers will benefit. Also, connection costs are proposed to have socialised elements, so that those seeking connections are likely to benefit more than those not seeking connections.

Third states *'… Framework will set out ..legislative and regulatory changes … futureproofed where possible'* – all laudable intentions and what would be expected in any case, but not a 'Guiding Principle' which can be used to establish a new Connection Policy.

It would be expected that 'Guiding Principles' would provide rules and assumptions which could be applied when developing a new connection policy, and possibly provide a yardstick as to whether what was proposed was acceptable e.g.

- *Customer Connection costs would be related to the cost they imposed on the network over the next 20 years based on the Long-Term Development Plan.*
- *Connection Capacity Costs would be based on MW of demand.*
- *Generators would pay for any extra costs associated with their connection, including full shallow costs plus a levy based on their share of the proposed Long Term Development.*
- *Hardship cases would be dealt with by external subsidies rather that by use of a lower allocation of costs.*
- *Prosumers would save/be paid for the energy cost involved but their share of fixed costs would not be evaded. If society wishes to provide an extra subsidy for Prosumers it should be transparent (-otherwise the wrong signals will be sent to customer sand market, and wrong decisions taken).*
- *Network development will be taking place in the context of XX GW of Offshore generation being connected into the network in North and South of Ireland, and this huge amount of renewable generation will then compete with Domestic solar and other generation.*

Q3. Do you agree with our proposed scope in relation to this connection review – including:

- **Are there other issues which we should take into account?**
- **Are there connection areas we should remove from the scope of the review?**

The requirement of the extent for the Distribution Network to be able to offload large Offshore/Onshore Generation needs to be taken into account as it will have a major impact on network development – much more than electrification of heat and transport.

So Renewable Generation is only available when wind blows or sun shines, and accordingly to maximise usage the load must be turned on when the renewable power is available.

But this means that EV, HP and other loads will be turned on in bulk at these times and will very likely overload every part of the network. Alternatively, the load is constrained so as to minimise Network investment and loading, in which case much greater levels of Generation and Electrolysers /Hydrogen Fuelled Generators are required.

So the trade-off between extra Network Investment or Extra Generation Investment must be made, and the outcome will dictate the amount of network reinforcement and new network required.

Accordingly, the Network model derived from the above will then indicate what capacity will be available as dictated by Strategic national requirements, and this network will be financed by all customers.

Consequently, it would only be changes to this network as produced by new connected load which would the need to be costed, and this is more likely to involve 'shallowish' costs.

Another significant issue to be addressed is whether the current tariff arrangements which encourage Domestic Generation will continue, and provide an attractive reward for PV installation, paid for by cross-subsidisation from other customers.

With large amounts of renewable offshore generation whose kWh energy cost will be lower than Domestic PV, will there be a justification to allow customers with PV largely avoid kWh tariff costs, yet keep the benefits of their network connection? In a 'thought experiment' where the electricity bill was 5c for a kWh and a Standing Charge of £120 per month, would any one install Domestic PV?

The issue of redefining the Import or Export capacity so that it was 'non-firm', available for control and that the capacity allocated was limited to use only at certain times of the day, or when the voltage was within certain ranges would be worthwhile.

Tariffs based on kWh give misleading price indicators ad drive sub-optimal investment. Tariffs should be much more heavily based on standing charges and with kWh energy costs separate
e.g. £120/mth standing cost ad 5c/kWh Energy cost – an extreme example but gets the point across!

Q4. Do you consider the current 'partially deep' connection boundary in NI appropriate?

The intention in all charging models is to identify the costs driven by the customer at all voltage levels and then ascribe them appropriately to the customer. In theory changes to the timing of future reinforcements brought about by the customers actions should be costed using NPV/Probability and ascribed to connections, if necessary sharing these costs between customers and providing refunds if other customers connected later to the same assets.

The problem with this methodology is that it is complex to apply and depends on a good knowledge of what future investments will be required where and when, yet the timing of these investments is based on a series of assumptions which will change over time.

Costing the direct connection itself is usually straight forward, and for simplicity the next step is to just move up one voltage level as costs could be followed to that level. However, this is no longer sufficient as a series of LV connected generators will have an impact two voltage levels above e.g. both at the 11/LV transformer and then at the 33/11kV transformer (which is possibly already loaded with large wind generators) and where there may be no capacity available.

So under this policy the customer cannot connect, nor can they be charged for reinforcement as it is more than 1 voltage level above them.

However, if loads from electrification or peak generation dictate updating of all upstream plant, these reinforcement costs will already be allocated to the generality of customer anyway. So setting a levy for such upstream capacity in such circumstances would be a simple and effective strategy.

Both load and Generation customers can act dysfunctionally without a strong price signal, but a simple levy will give the same signal everywhere.

Consequently the simplest solution would be to limit the size of the Generators/Load that can connect at each voltage level so that individual customers does not claim an excessively large share of capacity at lower voltage levels.

As an example, consider a large generator connecting to a 132/33MVA station with a generator/load which is the size of one transformer, applying for connection.

If the load is connected at 33kV the whole substation is sterilised for further load/generation as the forward and standby feeds are fully loaded. Alternatively, if the Connection Policy was to require connection at the higher voltage if the load was more than 50% of the size of a single transformer, then the connection would be at 132kV, and the full capacity of the HV Station would then be available for many other customers.

Had the connection been at 33kV the cost would have been very difficult to calculate because whilst the load might have taken all the substation capacity, even charging the costs of the assets would have been inadequate as the time take to build a second substation could be a decade, and the site required could be further away. For a correct allocation of resources the opportunity cost of the substation would have to also be included – likely a complex and contentious process.

In contrast, with a simple rule such as thresholds of load/generation per voltage level, the 'deepish' costs which would have to have been calculated and allocated now become part of the customers own direct costs. The transformer capacity used is from a transformer the customer installs at their own site.

Q5. Do you consider a shallow connection boundary to be appropriate in the NI context?

It is inappropriate, as it sends no price signals to customer of the upstream costs of connection. Consequently the customer is not motivated to look for a connection which requires less work as they are not bearing the extra costs.

To some extent this can be mitigated by having Voltage Thresholds at which various sized load and generators connect, as this effectively extends the 'shallow' connection further upstream.

Having a levy to pay for upstream costs when extra capacity is readily available is a good way of allocating costs which have been socialised to the particular customers benefiting from such earlier investment.

In short, customers should not be limited to 'one voltage level above' because costs are not limited to one level above, and this approach was only adopted originally for simplicity, not because it was appropriate.

In contrast, using the voltage level thresholds for connection, and additional levies where capacity is available are good approaches.

In the case of capacity not being readily available but required for the load/generator, then it is readily apparent that the load/generator is mainly driving the reinforcement. The Cluster approach could be applied here, or a policy could be used whereby the capacity provided would have it's cost allocated between the demand/generation driving it and the remaining MVA of transformer capacity then available. This reduces the initial cost for the developer to some extent and makes provision for future customer connections, which could be dealt with using refunds but with more complexity and delay.

So if (say) a new load required 40MVA it might be fed a 33kV from a new 2 x 132/33KV , 63MVA Transformers, so that allowing for standby the extra capacity available for future customers would be 2 x 20MVA Transformer. So costs would be 80/126 for the load driving the upgrade and 40/126 for future use (initially socialised).

However, if the load were (say) 63MVA, then the developer would have used all the capacity and get no allocation of socialised costs.

Of course for loads of 63MVA magnitude, the Voltage Threshold policy would have required connection at 132kV Direct so that the only costs involved would be the direct costs of the new 132kV Circuit and the 132kV Customer station at the customer site – customer would provide the transformer capacity directly on site.

Whether there is a different treatment for generation and load would depend on whether DUOS is equally paid by Generators and Demand customers. DUOS paid by Demand Customers could contribute toward the connection costs as a payment over time, whereas with Generation which pays little or no DUOS, all the costs must be upfront.

Where there is a mix of demand and generation the one site, costs driven by the larger peak demand will drive network size and should be the basis of overall costs, with those costs which would have been required to offset the demand load also being offset against total cost.

Q6. Do you consider a shallowish boundary to be appropriate in NI?

See Answer to Q5 above.

A critical issue is the extent and speed at which very substantial reinforcement of existing network will be dictated by either the need to offload Offshore Generation or meet the needs of Electrification.

In other words, if all the upstream network is already required to be uprated, then new connectees will be fed from a network where further upgrade work is not required, in which case levels of 'shallowish' become moot.

Q7. Do you believe that moving to a more shallow connection boundary in NI will deliver NI Renewable targets that otherwise would not be met?

No.

Generation is required in NI and will be bid for at prices that cover whatever costs are required to meet the generators rates of return. If shallow costs are cheaper the generators may simply make their return but at a lower price.

The issue in delivering Renewable targets is not the price of shallow connections but the timing and availability of the connection.

Possibly creating '**Renewable Hubs'** where the DNO takes the investment risk upfront, implements without delay and then shares costs as generators connect would be more effective.

Q8. Please provide evidence of the potential impact on energy affordability in NI if reinforcement costs were socialised further?

If the market for electricity is efficient and well functioning , and if cost socialisation could be arranged not to lead to inefficient investments, then there would be **no difference in costs to NI customers regardless of whether socialisation was used or not.**

This is because if socialisation reduces costs to developers and if market is efficient, then costs for electricity sold by the generators will reduce proportionally i.e. if no socialisation then the generators would require a higher price.

This assumes that socialisation, which tends to remove price signals to connecters, does not lead to connections costing in expensive locations simply because they are no longer directly responsible for the reinforcement costs.

The issue on whether socialisation would change affordability by 1-3%, 4-7% or 7-10% is not related to whether socialisation takes place, but to what the costs of Grid reinforcement may be, as these costs will find their way to customers either as increased DUOS or increased energy prices.

Q9. Can NIE Networks differentiate between RP6 Allowances, RP7 business plan connection requests and how these differentiate and have been factored into the analysis that has been done on the potential reinforcement costs analysis NIE Networks have completed?

Perhaps the issue is whether such cost allocations would be material and justify the complexity of the analysis required in each instance, as well as possible developer challenges to the allocations made?

Additionally, if Renewable Hubs are developed, then all the costs for generator connections in these areas are known and can be directly allocated.

Q10. Do you think that a developer led or plan led is the best approach for the future development of connections in NI?

Obviously it is not a good idea to pick an area with high levels of network capacity but where there is no wind there and developers have no sites!

Consequently, any 'Plan led 'approach must take into account the views of developers as to whether they would propose to install generation nearby.

Having said that, a 'Plan led 'approach is best for actually getting renewables connected as it has focus and economies of scale, whereas attempting to provide separate connections in many locations would be difficult on a manpower basis alone.

Q11. Do you think the current 3 moth timeframe for SONI and NIE Networks to issue a connection offer is appropriate?

The old adage *'measure twice, cut once'* comes to mind!

A connection offer in 3 months would be the smallest part in the project timeframe with issues such as Wayleaves and procurement of material taking far longer.

So far more critical to take the time to get the right answer, so 6 months would still be very reasonable or longer if required, as with a large volume of applicants' interactions will occur and these will lead to delay and complexity.

Additionally, as each generator connection impacts on the next, generator connection offers which remain open but not accepted cause significant delay, as studies must include them, yet when their offer lapses/declined then all previous studies need to be redone to account for the change.

To speed up offers have a limited period in which they must be accepted and allow no modifications after offer issued.

Q 12 If our legislation facilitated it, should obtaining Planning Permission be a pre-requisite to receive a grid connection?

In ROI Courts have decided that the Network Connections must also be considered when obtaining Planning Permission, so it is likely that this requirement could arise in NI also, and this would mean that Planning Permission was not able to be obtained without the connection requirements also being included in the application.

The likely intent of Q. 12 is to reduce the connection queue by eliminating applications less likely to succeed, and promote those which have a greater state of readiness e.g. Planning Permission.

An alternative approach would be to dramatically increase the cost of applications, so that these developers most likely to succeed would continue with their expensive application, whilst those unsure of their likely success would withdraw.

However, any cost set for the Application would have to be very significant to have any effect, and such fees would be argued against as being excessive.

An alternative approach is to auction positions in the connections study queue, so that developers who are most likely to be able to develop their site fastest will bid high, and , who are less sure, will bid low and be put at the back of the queue.

Q 14. Do you have any further information relevant to the subject matter of this call for Evidence that you think we should consider?

No.

Q 15 Please list any connection issues you have raised in order of priority:

- Decision on level of reinforcement that will be required by 2050 as this will dictate where reinforcements will occur and to what extent.
- Development of specific Principles against which connection policy can be assessed.
- Development of Threshold Voltages for specific levels of load/generation connection.
- Auction to determine position in queue for Connection study.
- Elimination of delays in accepting/modifying offers as this leads to further complexity.
- Limitations of the Import/Export capacity provided e.g. only available at certain times or under certain network conditions.
- Tariffs based much more heavily on Fixed Costs driven by kW capacity of connection, and variable kWh energy cost which could be at 5c /kWh

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