S&C ELECTRIC COMPANY
Excellence Through Innovation

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Sebastien Henry
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Our Ref: JC 2017-005 13 April 2017

Dear Sebastien,

S&C Electric Company response to the Directions Paper on System Security Market Frameworks (EPR0053)

S&C Electric Company welcomes the opportunity to provide a response to the proposal of a new Fast Frequency Response service to help support the National Electricity Market in the face of falling inertia.

S&C Electric Company has been supporting the operation of electricity utilities in Australia for over 60 years, while S&C Electric Company in the USA has been supporting the delivery of secure electricity systems for over 100 years. S&C Electric Company not only supports “wires and poles” activities but has delivered over 8 GW wind and over 1 GW of solar globally. S&C Electric Company has been actively engaged in deploying Battery Energy Storage Systems for over 10 years, supporting a full range of business models and using a range of battery technologies, at the kW and MW scale, and currently has 76 MW/189 MWh in operation. In Australia, S&C projects include the Ergon Grid Utility Support System in Queensland, which reduces peak loads and provides voltage support on rural Single Wire Earth Return lines and the 2 MW battery for PowerCor in Victoria.

In December 2015, Workstream 6 of the DECC and Ofgem Smart Grid Forum published their final report. I was part of the workstream and chaired the Distributed Generation and Storage Sub-group. As part of the final report we prepared a report covering “flexible connections” or options to recoup the costs of reinforcement when a new connectee triggers the reinforcement. I have provided a link to that report under the “Causer Pays” section in our response below, but I would be happy to discuss the other options we explored in the UK, if helpful.

S&C Electric are particularly interested in facilitating the development of markets and standards that deliver secure, low carbon and low cost networks and would be very happy to provide further support to the Australian Market Energy Commission on the treatment and potential of these technologies.

Yours Sincerely

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Introduction:

We are strongly supportive of the approaches proposed by the Australian Energy Market Commission in their paper of 23 March 2017 to delivering:

- Inertia
- Fast Frequency Response
- Managing Fault Currents
- Managing Rate of Change of Frequency
- Voltage Control

We also welcome the clearly defined roles and responsibilities for each approach.

Response

While broadly supportive of the approaches proposed, including the Immediate Package and Subsequent Package, we have some comments on the details of the proposals.

Batteries are already delivering FFR

Throughout the Directions Paper (e.g. page 44) there is a sense that FFR is a new and untried service. This is not correct and S&C Electric has delivered over 17 MW of batteries to deliver this service, mainly in the PJM market, but also the UK Power Networks 6 MW battery, which provided frequency response to the GB Transmission System Operator. S&C Electric delivered their first frequency response project, 2 MW, in 2011, so the use of batteries to provide a variety of frequency response services is well-established. The UK Power Networks battery was instrumental in allowing National Grid to assess the potential for a "rapid" frequency service, shaping the technical specifications for the Enhanced Frequency Response service tender.

These are only S&C Electric projects, but many other developers have delivered batteries to provide fast frequency services globally including the 10 MW battery at AES's Kilroot Power Station, in Ireland, has been operational for over a year and is used by EirGrid to provide rapid frequency response.

However, it is the PJM market that has provided the longest and consistent demonstration for the role of batteries in delivering a fast and accurate frequency response service. With reports from PJM indicating that 1 MW of fast acting response (batteries) displaces 3 MW of (slower) peaking high carbon plant, while delivering an efficient and effective service (PJM Interconnection, *Performance Based Regulation: Year One Analysis*, October 2013; and PJM Interconnection, *Implementation and Rationale for PJM's Conditional Neutrality Regulation Signals*, January 2017).

Batteries can deliver other services, including reactive power

System strength is a critical issue to address and the four proposed approaches are (page 72):

- reinforcing the network with additional lines and/or transformers
- switchable capacitor and reactor banks
- dynamic voltage control devices such as static VAr compensators (SVCs) and static synchronous compensators (STATCOMs)

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- synchronous condensers.

Batteries can provide many of the required services, either directly or as part of a hybrid system, which would allow the entire asset to deliver a broad range of services, while the above approaches can only address a limited range of system issues. The UK Power Networks Smarter Network Storage battery has a primary purpose to meet security of supply and avoids the need for an additional overhead line, third transformer etc. The same battery can deliver reactive power simultaneously to other system services (e.g. reactive and active power together) and provided frequency response.

Batteries can also deliver fault currents on weak networks, manage RoCoF and support voltage. Batteries can be deployed in one location and moved to another site, if, as is likely, the network evolves and either reinforcement can no longer be avoided or support is needed elsewhere, this minimizes the risk of having a stranded asset either on the network or at a generator site.

Generator Obligations

It is not immediately clear if the obligation to be placed on a newly connecting generator will require equipment that is *part of* the generator or equipment that is *on the generation site*. We would strongly support an approach that allowed generators to meet their obligation by placing equipment *on their site*, since not all generation technologies will be able to incorporate the necessary service within the generator.

TNSP Solution

A careful balance needs to be struck between requiring a TNSP to procure a service (opex) versus allowing a TNSP to own and operate assets (capex) that would deliver a service. Where that asset is electricity storage, with the flexibility to provide a range of services, the TNSPs (and DNSPs) are highly likely to be able to deliver maximum value to the end consumer because the NSPs can access many of the value streams that are available, while a third party provider may not be able to access multiple income streams (e.g. UK Western Power project with British Solar and RES, where the majority of the income streams accrue to the network operator: https://www.westernpowerinnovation.co.uk/Projects/Current-Projects/Solar-Storage.aspx) and are also able to coordinate the operation of the asset to ensure maximum efficiency (income versus cost).

Given the likely changes in the system there is a risk that any equipment deployed to manage a particular issue at a given time, will become stranded in the future. We agree with the AEMC that the NSP is best place to manage the broadest range of network/system issues and would have the best oversight of what technical approach would best apply in a given situation.

Causer Pays

The “Causer pays” principle is complex and as stated would not allow cost recovery from a departing generator that results in a reduction in system strength (page 79).

The ability to “free-ride” is also a concern (page 78), with the last connecting generator potentially bearing more of the cost, than is merited by its single impact. It is the cumulative impact of many non-synchronous generators connecting to the network that results in a reduction in overall strength (or the prior departure of a synchronous generator) and so all parties connected to that part of the system have contributed to

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the issue and have a role in the costs and the benefits. This is a widespread problem not constrained to Australia and networks globally, including the UK Regulator, have also struggled with the fair distribution of reinforcement costs. The Flexible Connections paper developed by the Distributed Generation and Storage Sub-group (chaired by Dr. Jill Cainey, now of S&C Electric) of Workstream 6 of the DECC and Ofgem Smart Grid Forum explored this issue and proposed a range of approaches to managing the costs of subsequent reinforcement:

https://www.ofgem.gov.uk/system/files/docs/2016/02/storage_and_distribution_generation_subgroup_supplementary_material.zip

A fairer approach to the distribution of costs associated with maintaining system strength, rather than "causer pays" should be developed. "Causer pays" is likely to ensure that the deemed "causer" that triggers reinforcement (or the requirement to fund network support) is unlikely to connect and seek an alternative connection location that doesn't have the additional cost. This will mean that the reduced strength on that part of the network will not be addressed by a future connectee nor the NSP.

This is a complex issue and merits further work before the imposition of new requirements for connectees and a cost recovery process, that may actively inhibit investment in the network to support strength.

Treatment of Storage as "Generation"

The AEMC has taken the view that electricity storage is "generation":

"the Commission is of the view that any system that exports electricity to the grid is a generating system. A storage device that intends to export electricity to the grid should therefore be registered and treated as a generator" (AEMC, *Integration of Storage: Regulatory Implications, Final report*, 3 December 2015, Sydney).

This means that batteries connecting to a network will be treated as generation and so potentially trigger the "Causer pays" approach to reinforcement, when the battery may actually be connecting to resolve a constraint issue. This is one of the many issues that arise when treating storage just as generation. It should be noted that the load profile of a storage device is more significant that the export profile due to storage losses. Additionally, the "swing" of a battery from full import to full export, in a matter of milliseconds, will, when batteries are large, have a significant impact on the system.

In other jurisdictions (UK and Europe) a separate regulatory asset class is being considered for electricity storage, definitions are already developed and connection codes at both the Transmission and Distribution level are under modification to better take account of and manage this technology.

We would be concerned if the current AEMC view that batteries should be treated as generation, resulted in a "Causer pays" approach in a situation where the batteries are being deployed to support the network. We accept that some third parties, who may wish to provide a system service may need a fully unconstrained connection (this is largely dependent on the service availability specifications*), which may result in the need for reinforcement. This is a strong argument for the role of NSPs in the ownership and operation of batteries to support the system, since NSPs are best placed to deploy solutions appropriately.

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*The majority of the UK Enhanced Frequency Response (EFR) providers opted to make themselves "100% available" over the 4-year term of the contract, resulting in the requirement for fully unconstrained connections, with all 201 MW connecting at the Distribution level to deliver a Transmission level service. The EFR service was developed by the Transmission System Operator without the knowledge or consultation with the Distribution Network Operators (DNOs), resulting in huge pressure on the DNOs with connection requests and difficulties in understanding the technical issues that would occur on the Distribution Network during delivery of a very rapidly responding service. The UK situation illustrates the need for close cooperation between all parts of the system, when developing a new system service, regardless of the nature of that service.

Technology Neutral Approaches

We are concerned at the apparent requirement for the deployment of Synchronous Condensers by either a generator or NSP to improve system strength (pages 81-82). There may be other technical solutions that can improve system strength that may be more efficient and deliver wider benefits at lowest cost.

Generators and NSPs should together consider what is the most appropriate technology to deliver maximum benefits and not only resolve the specific issue as a result of a single connectee. This may necessarily complicate the cost recovery process, because some aspects of the technical solution may address other broader system/network issues than the connection of a particular generator. A process needs to be developed to assess the fair costs that can be levied on the connecting generator, versus the entire cost of the mitigating technology and the wider benefits provided by that technology.

This approach would deliver maximum system benefits at lowest cost and reduce the risk of over deployment of one single technology, that may later become stranded.

Deadband Issues for Conventional Generation

If the framing of FCAS has unintentionally resulted in a widening of the deadband response of conventional providers of inertia/frequency response, and there is evidence that this is the case, resulting in an increase in the number of events and hence costs of running the system, then this should be resolved as a matter of urgency, as it may be possible to resolve some of the current system security issues by returning to tighter deadbands.

The observed widening of deadbands has only highlighted the wider issue of falling inertia, so the approaches proposed in the paper are still important and valid, but the immediate requirement for new inertia and FFR services may be reduced and it makes sense to minimise the immediate costs by ensuring the inertia and frequency response that is already available on the system is used appropriately, while ensuring that the NEM is ready for a future where inertia and frequency provision are tight.

Flexible Connections – Considerations, Risk and Issues

Summary

WS6's DG/Storage group has initiated a discussion around Distributed Generation Flexible connections, through which DG customers receive a connection offer from the network operator detailing a time-restriction or dynamic capacity-management restriction in order to facilitate a connection to a constrained area of the network. This paper addresses the following questions:

- Should DNOs (and DUoS customers) bear some of the financial risks associated with curtailment of DG? What level of risk should they bear?
- What other methods of risk mitigations are there available to connectees who opt for a Flexible Connection?
- What happens when reinforcement is triggered at a later date? Should existing DG customers on flexible contracts pay a portion of the cost? What mechanism should be used to set the level of contribution?

In considering the first and second of these issues, the group identified four scenarios under which DG customers may connect to the distribution network. The first is a traditional 'firm' connection. The second is a simple flexible connection with no mechanism for sharing curtailment risk. The third and fourth scenarios represent possible risk mitigation mechanisms which might emerge in conjunction with flexible connections in future. This paper considers the risks, costs and benefits of each scenario. It also considers the potential barriers and enablers for the scenarios. This sub-group proposes to carry out further work to develop recommendations for putting enablers in place/ removing barriers to the scenarios identified.

In relation to the third question, the group also considered how and when reinforcement might be triggered and paid for in areas where DG customers have connected on flexible contracts. The annex to this paper presents an example mechanism for how DG on flexible contracts could contribute to the reinforcement costs as their connection becomes firm.

Contents

Background on Flexible Connections

In order to comply with its existing licence obligations, the DNO offers terms for connection with a generalised right of network access (unless specifically requested otherwise by the customer), which would typically allow for unconstrained access to the requested import and export capacities under normal (intact) network conditions, including any need to upgrade or reinforce the network if applicable. Although in the years leading up to ED1 only 5% connections required network reinforcement, where it is required, the cost is shared between the connecting customer and DUoS customers as a whole.[1]

When a Distributed Generator (DG) requests a connection to a constrained/saturated area of the distribution electricity network, the DNO can offer a flexible connection. Under these schemes, these DG customers receive a cheaper and earlier connection. In return, they accept they will be subject to curtailment, e.g. real-time reduction of the generator's output depending on the network's operating conditions. This arrangement delays or avoids additional reinforcement work, meaning that flexible schemes potentially benefit both DUoS customers and DG compared with traditional schemes.

Flexible schemes have been used as a facilitating mechanism to allow more generation onto the existing network. However, uncertainty in the level of curtailment experienced during operation of flexible connections introduces a level of risk to DG developers and may act as a barrier to financing generation projects. Flexible connection offers must also comply with the rules governing the allocation of renewables support under Contracts for Difference, where such support is sought.

1. Forecasting future curtailment levels

Forecasting with a good level of accuracy future curtailment levels in the networks is a difficult task, due to the uncontrollable factors such as:

- Constraint management system not performing as expected.
- Significant changes to the input assumptions of the curtailment estimate that are not within the control of the DNO and are difficult to predict, including:
  - Load growth
  - Load drop
  - Growth of DG, i.e. micro-generation
  - Profile of generation and demand modification (due to intro of storage for example)

This introduces a level of uncertainty for both generation customers and DNOs. For generation customers the risk is both revenue loss and higher borrowing costs for future projects. For a DNO, the risk of curtailing customers more than envisioned is largely reputational (both in managing the customer's expectations and in providing a good service broadly).

2. Scenarios and distribution of risk/costs and benefits

If the customer requests a connection to connect within a constrained part of the network, there are several ways to address the risks. Four scenarios have been identified and are analysed below.

[1] NB. Where new connections have triggered reinforcement, DUoS customers have paid around 70% of the reinforcement cost. However, the non-reinforcement elements (ie the sole-use assets) are paid for entirely by the connecting customer.

Scenario 1: Traditional non-flexible connection

The DNO analyses the available 'headroom' in the network for the type of generation wishing to connect and, in accordance with engineering guidelines and principles, offers the most economic, coordinated and efficient connection design for the generator. No operational network constraint is imposed by the DNO during intact conditions, and generators may export up to their full registered export capacity, in accordance with their business requirements and physical restrictions such as plant availability and load factor.

- **Risks / costs**:

For the generator: Cost of connection can be high if reinforcement to the network is required, and resulting connection timescales can be long, taking months or even years to reinforce existing assets or build new lines. Given the longer connection lead times, projects can face delays and changes to their financing arrangements. Also, market conditions could vary while waiting for a connection and this may significantly alter the project's value. High connection costs themselves can simply make the project economically unviable.

For the wider market: Too many saturated network points can limit the growth of generation, adding risk to national generation margins (energy security) and restricting competition in the generation of electricity. This risk is particularly relevant to project developers that are required to locate within a particular geographical area such as community projects.

- **Benefits**:

For the generator: No constraint expected to their output from a networks point of view, hence greater certainty of forecast output which assists with securing project finance.

Scenario 2: Flexible connection, no compensation

In this scenario, the DG customer is offered a flexible connection with scenarios of forecasted curtailment. Connection costs and times to connect are lower than those required for scenario 1 which is the incentive for developers to consider this alternative. Such flexible connections are being used at the moment by a number of DNOs in certain locations, although not always with forecasted curtailment. Active Network Management (ANM) techniques are being used to curtail the generators' output in real-time when necessary to keep the system within acceptable operational parameters.

It is expected that over time the curtailment forecasting methods can be improved and standardised to limit curtailment risk and better enable new projects to secure financing.

- **Risks / costs:**

For the generator: Estimated curtailment levels are given by the DNO to the generator using best efforts at the time of making the offer, covering more than one future scenario; however these forecasts are nonetheless not contractually guaranteed. Actual curtailment can vary relative to forecast issues described above. This additional degree of unpredictability (beyond normal plant variations and market conditions) adds a layer of complexity and risk to DG projects , which adversely impacts the availability and terms of project financing.

For the DNO: If the level of curtailment is much higher than the amount predicted at the time of connection, there is a risk of reputational damage and challenge by generators. Also, the absence of a compensation payment means that there is no locational investment signal and therefore no trigger to invest to relieve the constraint.

For the wider market: financing risk arising from uncertain outturn curtailment levels increasing the cost of new projects, potentially inhibiting new generation.

- **Benefits:**

For the generator: cheaper and earlier connections that may allow projects to become economically viable, which would otherwise not progress under scenario 1.

For the DNO: Providing the customer with a viable alternative allows DNOs to provide improved customer service; allows DNOs to make better use of existing assets.

For the wider market: More generators can be accommodated and sooner, compared with scenario 1, better facilitating competition in generation.

Scenario 3: Flexible connection, with a 'cap' (compensation)

As in scenario 2, a flexible connection is offered, but there is a cap to the level of curtailment to the generator, above which a financial compensation is paid. The cap would be intended to provide a backstop position, and not to guarantee a particular forecast. The methodology for defining the level of the cap would need to take into account a number of significant factors, such as the curtailment forecast scenarios and the cost of the appropriate network reinforcement which would otherwise have been triggered by providing an unconstrained connection. The cap should be set at a level that reflects the benefit received both by DUoS customers and by the connecting DG, notably through avoiding network reinforcement costs.

The concept of compensation for lost energy production makes the issue of measuring lost output very important. One solution is for generators with these types of connection to provide a *power available* signal, such as is already used in Ireland, and such has been agreed to be included in GB Grid Code[2]. Such a signal can be validated against the metered output in unconstrained conditions to verify accuracy. A financial value can then be ascribed to the constrained lost energy, either under prevailing market conditions, such as for example the relevant Contracts for Difference strike price, or potentially to an agreed up-front unit price.

In concept, the cap encourages good forecasting and encourages DNOs to maximise availability of the system. Furthermore, the constrained lost energy could potentially act as a locational signal for network investment.
However, there will be issues beyond control of the DNO which can cause excessive constraint which, on the face it, would be compensated under scenario 3. One such example could be a rapid proliferation of micro-generation, whereby an area of previously uncongested network is rapidly and unexpectedly filled up. All compensation costs would need to be appropriately recovered or funded. Funding options could include using avoided reinforcement costs that DUoS customer would otherwise have paid under a firm connection scheme. Alternatively, the DNO could charge a premium to all flexible connections customers to recover the costs. Further research is required to explore how the level of capped constraints and compensation could be determined and to demonstrate the net benefits of this approach. However, any cap and compensation scheme should not result in DNOs incurring greater costs on behalf of DUoS customers than would have been the case under a traditional non-flexible connection.

- **Risks / costs:**

For the generator: There is potentially an incentive for DNOs to forecast a very high level of curtailment, to mitigate forecasting risks. This could drive up the cost of connections and reduce the value of projects. The generator needs to

[2] Grid Code Modification Proposal GC0063.

invest in appropriate communications systems to enable instructions to be received, acted upon, confirmed, and recorded.

For the DNO: DNOs are put in a position where they have to run the risks of forecasting variables that are not within their control as described above. Unforeseen compensation payments would drive up the network costs which ultimately are paid for by the customers.

For the wider market: Although this scenario reduces the financial risk for the DG customer, it does not physically solve the problem of constrained networks areas; therefore any additional generation permitted under this scenario compared with scenario 2 may be limited if permitted to connect at all. Another risk is reputational: it could be perceived by customer groups that generators are 'paid for not generating', and that the customer is perceived to be paying these costs. There are precedents in transmission for this kind of concern.

- **Benefits:**

For the generator: A visible and capped constraint risk allows generators to better obtain project finance. The development of non-firm projects and associated building up of funds for grid reinforcement would remove the cliff edge currently faced in areas of congested grid and address some of the concerns around current deep(er) charging for connections.

For the DNO: A better level of customer service would be perceived by the generators; any increase in connections above scenario 2 may be viewed as better facilitating competition in generation.

For the wider market: Competition is encouraged in that more generators may connect than in either of the previous scenarios. The risk premium added to generators under scenario 2 is capped, which could lead to lower generation costs.

Scenario 4: Flexible connection, with a benefit transfer

Scenario 4 involves a more market-based mechanism with a view to solve the physical constraint. Curtailment could be reduced by three methods

a. Demand in the area increase to match output at times of potential curtailment
b. Another generator decreases output
c. Electricity storage[3]

Where the connectee decides to manage their output via their own arrangements, such as storage, behind the meter, there is in theory no need for the DNO to be involved. However, in practice the DNO may wish to reassure themselves that the connectee's arrangements are failsafe, i.e: that they will not ever exceed the export limit imposed. The DNO will be aware of the generators involved because the nameplate capacity of the generator will be higher than the maximum export capacity in the connection agreement.

This option has the potential to make DG projects more bankable and also reduce total system costs, as the mechanisms are geared towards allowing more generation into the system when they would have otherwise been curtailed off. There are many options for how this curtailment 'service' could be provided, depending on the party involved:

[3] Barriers to storage facilities offering flexibility services to the DNO are dealt with separately in this subgroup's *Storage and DG Services* paper.

- DNOs, taking on a "DSO" role (more similar to a system operator, with clear regulation in place to facilitate this)
- Aggregators/ market makers
- End providers such as local demand
- Other generators
- Storage

This scenario may afford opportunity for community involvement and in community schemes to provide the appropriate service.

Each option has different pros and cons and this paper does not assess which party may be best placed to manage the corresponding risks. It is important to point out that for any of these alternatives, DG customers can have bilateral arrangements to minimise curtailment but they must be connected behind the same constraint. If not, it does not address the network problem (which is the driver for having a flexible connection). DNOs might not have visibility of these contracts but would continue monitoring the constraint at established measurement points to make sure that the network parameters stay within limits.

It should be noted that Scenario 4 can be used in conjunction with Scenario 2 and Scenario 3 above. In other words, a generator can make arrangements to minimise their constraint whether or not there is a cap above which they are compensated.

- **Risks / costs:**

For the generator: Costs could be higher than under scenario 2 because the generator would be required to pay for the 3rd party service.

For the DNO: Diversion of risk through the 3rd party service removes a potential investment signal to reinforce to remove the constraint.

- **Benefits:**

For the generator: Constraint risk would be much lower than in scenario 2 and therefore the project would be better placed to achieve financing. As DNOs don't have to mitigate forecasting risk, costs of connections would not include a premium.

For the DNO: No uncertainty costs would have to be incurred and passed on to customers as a result of forecasting errors.

For the wider market: Under this scenario, a greater share of low carbon technologies is being facilitated into the market when compared with scenario 1, possibly at optimal cost. Customers that can provide load flexibility would be able to receive benefits for providing this service to generators. Furthermore, under this scenario, constraint would actually (physically) be reduced, allowing more low carbon generators (when applicable) into the system.

4. Reinforcement under flexible connection

Reinforcement may come in the form of a specific network build or upgrade which provides additional capacity. In this context, it could also include third party storage or other solution to deliver additional capacity in place of a traditional network asset upgrade. The cost/benefit analysis requires an understanding of the time-varying nature of users' demand and generation profiles, which may result from more active system management of the distribution networks.

In general, flexible DG connections should not be considered a long term solution for every connection in the network. It should be recognised that many users may require flexible connections for *timely* network access, with firmer-access to follow on completion of relevant reinforcements (similar to the principles of National Grid's Connect & Manage framework). Currently there is no operational cost signal to inform DNOs where best to invest for facilitating DG connections, whereas the constraint applied to flexible connections could potentially become a proxy for such a signal. Furthermore, the present charging framework (apportionment rule and high-cost cap rules) typically anticipates a single pre-connection user[4] as the trigger for reinforcement, requiring up-front capital contributions which can represent a very high proportion of the total reinforcement cost; this itself can be a significant hurdle for progression. Flexible connections for multiple users behind a constraint could, with an appropriate contractual framework, form part of a needs case to justify a reinforcement, which may also spread the cost between a number of users including those with flexible connection contracts.

For reinforcement to follow after a flexible connection there needs to be consideration of how and when to trigger and recover the costs of reinforcement, in such a manner which permits network development and facilitates new connections without adding undue increased cost to existing customers. Specific considerations include:

- How to determine when the network has reached a certain level of curtailment which makes it optimal to reinforce instead of continuing to curtail generation.
- Cost recovery, or cost apportionment, from converting flexible customers to firm customers, for example when a subsequent new user triggers a reinforcement which relieves a constraint, or if the existing user specifically requests an upgrade to an unconstrained connection.
- When precisely is the trigger for reinforcement
- How constraint costs can be linked to reinforcement costs (e.g. annualised and charged post-connection)
- How existing customers behind a constraint can contribute towards a subsequent reinforcement which relieves (or partially relieves) the constraint.
- What the appropriate reinforcement is, e.g. balancing a short-term solution versus a long-term reinforcement rather than performing both.

Finally, it is important to discuss what happens once reinforcement upstream is carried out. Generators that have connected under a flexible scheme could be required to contribute towards the costs of this reinforcement either as a lump sum or as an annual payment for the extra generation that they are able to input into the system. Addressing these issues would accelerate the roll out of these methods ensuring that customers get the benefit from a cheaper and faster connection.

4.1 Minimum access rights

It can be useful to set a minimum level of export which a generator can expect to be able to output even in the event of certain network constraint scenarios. It is instructive to consider the current situation for flexible connection access rights in Northern Ireland, where generators are issued with two export figures – a Maximum Export Capacity (MEC) based on generator ratings and a Firm Access Quantity (FAQ) which expresses the maximum level of its financially firm transmission access rights. Over time, as reinforcements are completed, it is expected that the FAQ rises to meet the

[4] Or precisely concurrent users, in the case of consortia.

MEC. The introduction of the FAQ can make it easier for the project to secure finance because it would start to receive compensation for constraints in accordance with SEM rules.

4.2 Consideration of Electrical Storage

Electricity storage is an option that could allow the management of connecting DG to a constrained network. There are several commercial alternatives for this solution:

a) The DG connectee may invest in their own storage facility (behind the meter) to manage any constraints. Despite the falling costs of storage, the business case for such investments is not enhanced by the fact that the efficiency of a storage device implies losses in energy and hence income from potential ROCs; therefore in some cases, the constraint situation may have to be acute for the generator to prefer this investment. In this case, measuring the storage's activity and where the meter is located is critical. Additionally, storage behind the meter may or may not be able to provide services to the wider network and system, which would need to be explored further with the TSO and DNOs. For example, if the storage connects behind the meter, the DNO will control the generator directly; however, it is unlikely to be able to offer services to the TSO, however it could offer services to the TSO if the storage and DG were operated mutually exclusively 'behind the meter'. If reactive power evolves to be a service, the DG may offer reactive power to DNOs, or it may do arbitrage via Power Purchase Agreements. In any case, if the storage is used to provide services beyond managing the constraint for the DG connectee, then income stacking (i.e. several contracts) and visibility issues would need to be addressed. If the storage connects with separate meter, the option of having a controlled storage and a controlled DG would need to be managed by the DNO.

b) The second option is for the DNO to invest in storage to manage a constrained network. It is not clear how this storage would be funded, but if it was a DNO owned asset then there is the potential for the storage to have wider network and system uses. Currently, the benefit accrues more to the generator while for the DNO storage is too expensive to use only for curtailing generators. In this case, other services would have to be considered to break-even, with the risk on the DNO to pay the associated costs. It is still unclear if high income from ancillary services would be allowed to DNO. For this option, not only must there be clear definitions on DNOs operating storage, but the issues of income stacking and visibility would also needs further work. Finally, double charging of levies and obligations is a potential barrier that must be analysed.

c) Finally, a third party may invest in storage to help both the DG connectee and DNO manage a constrained network. In this option, DNOs must rely on the device for security of supply and third parties may find a more lucrative option elsewhere. However a third party would need to be made aware that an opportunity existed to provide storage. Income stacking, visibility, double charging of levies and obligations are also barriers that need further clarification specifically for DNOs and service providers to have common understanding of how to create appropriate connection terms.

4.3 An example of reinforcement after flexible connection

This section outlines one example of how reinforcement could be delivered after a number of generators connect behind a specific network constraint. In this example the cost of reinforcement is compared with the projected annual generation revenue loss due to the constraint, and the reinforcement is triggered when the constraint cost is higher. Once complete, the reinforcement removes the constraint for these generators, who instead pay an apportioned annualised charge towards the cost of the reinforcement. The scheme is setup such that the resulting annualised reinforcement charge is no higher than the projected annual revenue loss which would have been incurred if the constraint had endured. For the generator, the result has a similar effect to capping the constraint. For the DNO, it may be seen to facilitate both flexible connections and efficient longer-term connection solutions. A more detailed example is given in Appendix A.

The principles of this scheme answer most of the bulleted considerations of section 4 above, such as determining the trigger point and offering a solution for cost recovery. The terms of the flexible connection contract could set out the triggering methodology for the avoidance of doubt, and oblige payment of the relevant share of annualised reinforcement charge as a condition for remaining energised. However, it is not yet clear exactly how the most appropriate reinforcement is to be identified: The discrete nature of network assets, particularly at EHV level, may assist (for example, 132kV/33kV transformers are typically offered in very few capacity levels); further work would be needed to establish to what degree the first few flexible connection contracts would have to be specific or exclusive in detailing a reinforcement, and whether there could be scope to revisit the reinforcement design in the event of additional local flexible-connection customers.

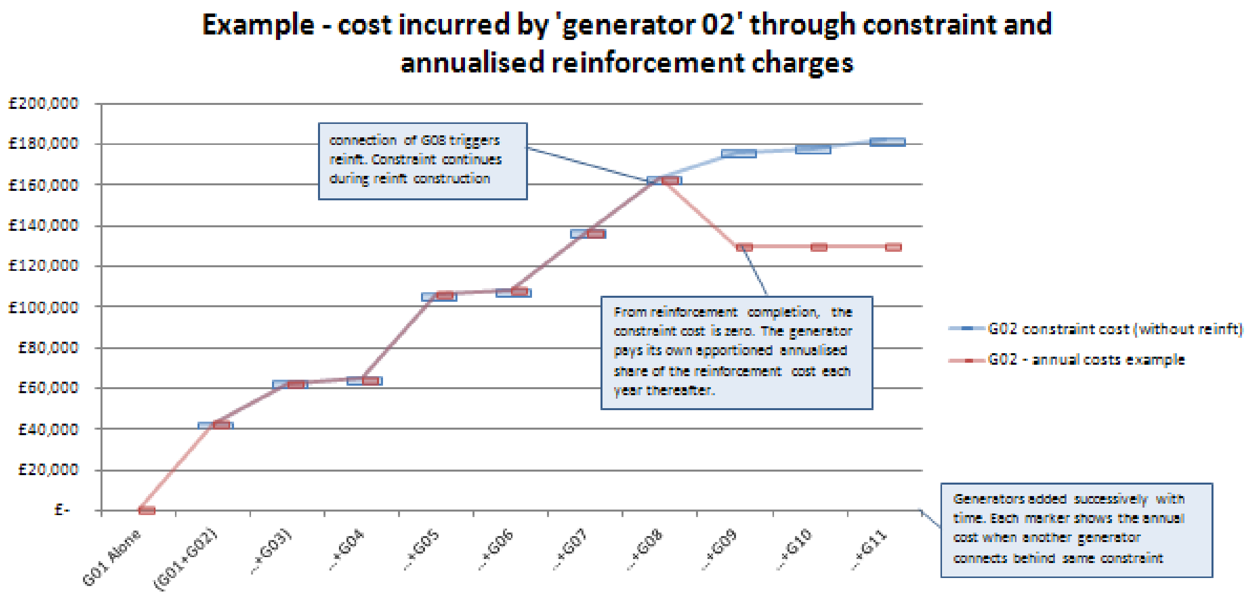
A significant item for consideration is the constraint modelling used to trigger the reinforcement – while all parties will necessarily acknowledge that it cannot be exact, *excessively* under- or over-estimating the constraint could lead to inappropriate triggers and potentially undesirable incentives for connecting generators. Another item for development is to establish whether the reinforcement works would require any specific financial underwriting ahead of completion or whether the existence of flexible generation operating behind a constraint with appropriate contractual obligations sufficiently de-risks the investment.

Appendix A – More example of reinforcement after flexible connection

This appendix continues from the description in section 4.3. A model is developed to estimate the likely lost energy imposed by the network constraint, and updated with each subsequent flexible-connecting generator. This lost energy can be converted to an annual cost using appropriate market data according to an agreed formula, in a manner similar to UKPN's Flexible Plug and Play scheme. In parallel, a specific reinforcement is identified and the cost is annualised in a manner similar to transmission connection asset charging[5] (the design could be potentially revisited as the actual generation mix progresses).

A worked example considers a 50MVA EHV reinforcement costing £10m, equating to an annual charge of approximately £650,000 using a hypothetical set of rates (depreciation, permitted rate of return, and so on). In this example, the flexible constraint is applied pro-rata and the constraint increases approximately linearly with the connection of each successive generator. Eventually a new flexible-connecting generator, taking the group total to approximately 42MW, connects behind the constraint and the generator group now anticipates greater than £650,000 of annual revenue loss due to the constraint; therefore the DNO now proceeds to construct the reinforcement.

Once the reinforcement is complete, each generator in the group (under the terms of its contract) pays to the DNO its apportioned share of the annualised reinforcement charge; e.g. a 10MVA generator in the group could be required to pay 20% towards this 50MVA reinforcement, an annual charge of approximately £130,000. The annual charges continue for the life of the reinforced asset as appropriate; a termination charge may be considered appropriate if the connecting user disconnects before this time. An example of the costs incurred by a single 10MVA generator in the group is shown in Figure 1. This generator is second from a group of flexible connectees to become operational, and constraint increases with each generator thereafter until the reinforcement is both triggered and completed. The annual 'cost' incurred by the generator is therefore shown by the red line (note that constraint continues in the interim between reinforcement trigger and completion).



[5] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Connection-Charges/

Questions to SGF Workstream 6

- Do you agree with the four scenarios outlined?
- Are there any additional barriers/ enablers for the scenarios that the sub-group should consider?
- Are there any additional risks/costs and benefits for the scenarios that the sub-group should consider?
- Do you agree with the further work proposed for developing the example of recovering reinforcement costs after a flexible connection? Are there any other considerations the sub-group should consider?