Accelerating Renewable Connections (ARC)

Learning Report 2

The Changing Nature of the Transmission and Distribution Boundary

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Abbreviations

ANM	Active Network Management	ICT	Information Communication Technology
ARC	Accelerating Renewable Connections	LFDD	Low Frequency Demand Disconnection
BCA	Bilateral Connection Agreement	kV	Kilovolt
BEGA	Bilateral Embedded Generation Agreement	kW	Kilowatt
BELLA	Bilateral Embedded Licence Exemptible Large Power Station Agreement	LCT	Low Carbon Technology
BM	Balancing Mechanism	LIFO	Last In First Off
BMU	Balancing Mechanism Unit	LMS	Load Management System
BSC	Balancing and Settlements Code	MP	Measurement Point
CUSC	Customer Use of System Code	MW	Megawatt
DER	Distributed Energy Resource	NGET	National Grid Electricity Transmission
DG	Distributed Generation	NETS	National Electricity Transmission System
DNO	Distribution Network Operator	RAA	Restricted Access Agreement
DSR	Demand Side Response	SO	System Operator
DSO	Distribution System Operator	SOF	System Operability Framework
EBS	Energy Balancing System	SoW	Statement of Works
ENA	Energy Networks Association	SPT	Scottish Power Transmission
EFR	Enhanced Frequency Response	SQSS	Security and Quality Security of Supply
ERF	Energy Recovery Facility	STOR	Short Term Operating Reserve
GSP	Grid Supply Point	T-D	Transmission-Distribution
GW	Gigawatt	TEC	Transmission Entry Capacity
ICE	Incentive on Customer Engagement	TO	Transmission Operator

1. Executive Summary

The rapid growth in Renewables and Distributed Energy Resource (DER) across the UK has meant that many areas of the transmission and distribution network have quickly become congested for new connections under conventional design and commercial practises. In 2010, the impact on the Scottish transmission system and the need for transmission reinforcement became clear with a 'queue' of projects emerging where connection was reliant on transmission reinforcement. The System Operator (SO), National Grid, introduced through industry consultation, a number of initiatives including 'Queue Management' and 'Connect and Manage'.

- ✓ 'Queue Management' was implemented to allow those developers who were lower down the queue but ready to proceed to construction with their projects, a way to advance ahead of those projects who were not able to proceed but retaining existing grid capacity, mainly due to lack of necessary planning consents to construct.
- ✓ 'Connect and Manage' was introduced as a means of accelerating the connection of generation ahead of transmission reinforcements. Since 2010, circa. 1.77 GW of generation has advanced under the Connect and Manage incentive – with 1.14 GW of this connected in Scotland[1]. Under this mechanism, projects connecting under 'connect and manage' would be managed mainly by overload protection schemes against to mitigate any possibility of network overload.

These commercial and technical innovations provided an opportunity to accelerate connections subject to transmission constraints. The transmission and distribution boundary constraint problem occurred in Scotland in advance of other areas across the UK due firstly to the rich renewable resource available across Scotland but also due to the classification of the 132kV network as a transmission voltage, compared with 275kV and 400kV in England and Wales. In areas with high penetration levels of generation connected to the distribution network, reverse power flows from the distribution networks onto the transmission network has become more the norm at several Grid Supply Points, as detailed in example figure 1.

[1] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=43723

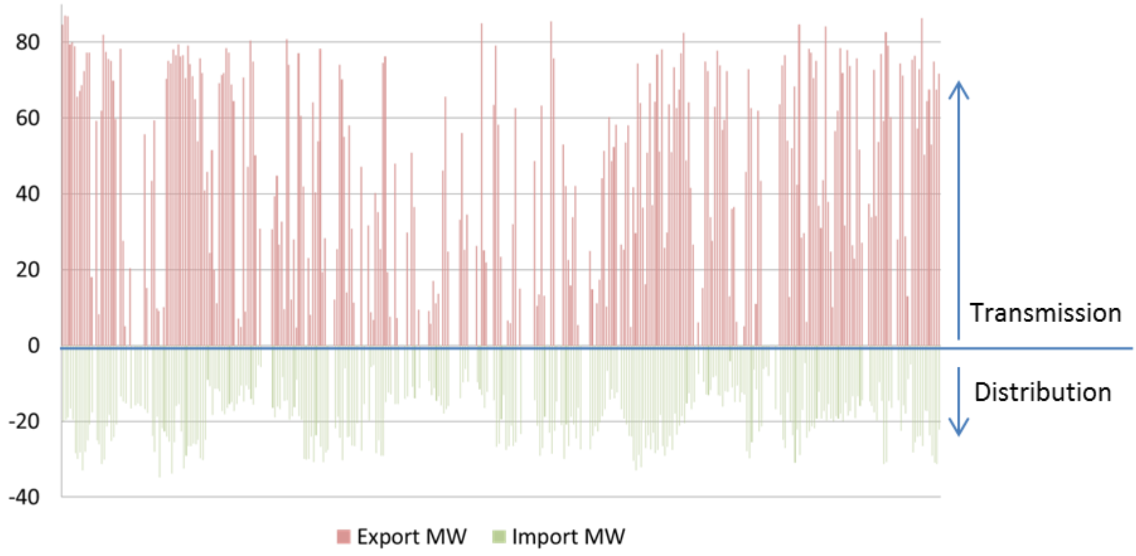


Figure 1: 2012 Annual Half Hourly Import/Export Profile at Dunbar GSP (Pre-ARC)

The Accelerating Renewable Connections (ARC) project set out to demonstrate an alternative means of connecting additional embedded generation subject to transmission constraint at the GSP. The case study of the 'Exporting GSP' has been the cornerstone of the ARC project. The project aimed to trial new technical and commercial solutions, in collaboration with the SO, to manage additional distribution connected generation against the Dunbar GSP transmission / distribution constraint.

Initially we expected this would be achieved by sharing information with the SO, agreeing the control philosophy and hierarchy of control with the TO and reflecting this new commercial arrangement within a suite of distribution connection agreements. We believed that the technical challenge would be the greatest; delivering a robust solution and datasets that both parties could rely upon. In reality, the greatest challenge was establishing a contractual agreement between all parties. We found the potential for ANM actions to conflict with the existing market arrangements between parties (such as embedded balancing mechanism participants and the system operator) as a key barrier to the delivery of the project objectives. A fundamental element of this project was ensuring we continued to comply and fulfil our Connection and Use of System Code (CUSC) obligations. No derogations were sought or agreed during the execution of the ARC project as we believed from the beginning that we would implement an innovative solution within the current regulatory and network code structure. This report details those challenges that we overcame and provides learning on the changing nature of the transmission distribution interface; hopefully setting a learning benchmark for the future Transmission – Distribution (T-D) interface.

The project generated the following learning outcomes:

- ✓ The importance of visibility of SO instructions implemented against existing Embedded Balancing Mechanism Units (BMU) by the ANM System to ensure that no unintended consequences occur whereby managed generators fill the void of the network capacity created following a reduction in export by BMUs as instructed by the SO

- ✓ Existing network protection arrangements, support the acceleration of renewable generation projects, but are not sophisticated enough to manage load flows in real-time and often result in generator disconnection from the system for long periods of time.
- ✓ The connection of small scale embedded generation within the 11kV and LV network can erode capacity and increase the frequency of generator disconnections under 'connect and manage'.
- ✓ Outage management of the transmission network in areas with ANM connected DG has the potential to become more complex for the SO and TO in the longer term; aggregated non-BMU generation can become so great that even paying BMUs to come off the system may not be enough to guarantee uninterrupted network access during a system outage.
- ✓ The requirement for a co-ordinating party who has visibility, control and a direct contractual arrangement with all assets connected at Distribution level, such as a Distribution System Operator (DSO) will become of greater importance in future.

Beyond the DNO/SO interaction we also worked with the Transmission Owner (TO) to better understand the investment signals needed for reinforcement. The investment case for transmission reinforcement can be very difficult for any individual DG developer to fully understand when their distribution connection is dependent upon completion of wider transmission reinforcement. By working with developers as a consortium to understand progress of each of their projects and any affect that this could have on the remaining parties, we were able to ensure that each party was fully aware of the capital cost associated with the GSP reinforcement, why this was necessary and how this would benefit the delivery of both their individual projects and as a collective group. There was also openness and transparency between all parties on how costs would be apportioned throughout the process and how any design changes for one project could impact upon the rest of the consortium. The ARC project developed a two-stage connection offer agreed with the SO and TO respectively, allowing customers to benefit from a managed connection that would be facilitated through the implementation of ANM at Dunbar GSP, as an interim solution (Stage 1) whilst also committing them to paying their contribution of connection asset works at the GSP and securitising the wider transmission reinforcement works (Stage 2) that would realise a firm connection against transmission assets upon completion, scheduled for 2021.

Through implementation of a two-stage connection agreement, this provided flexibility for both the customers seeking connection and the necessary investment signal for the network operator. With all parties completing their projects, the transmission reinforcement is a necessary investment as ANM on an enduring basis is not feasible due to the reliance within the Dunbar GSP area of a single large 33kV demand customer and mix of technology that was seeking to connect. However, it was also recognised that had certain generation parties fallen away and failed to build out their projects, the Stage 1 connection offer for some of the smaller developers, mainly wind developers, would have been translated into an enduring connection arrangement facilitated through the ANM system. The implementation of this new connection offer therefore provided flexibility to allow managed connections to accelerate their connection. For the transmission network operator, as developers start to construct and connect their projects, this represents a clearer signal to move forward with wider transmission reinforcement which is also more efficient on a £/MW connected as all parties are either contracted, connected or in construction of their projects prior to the delivery of the transmission reinforcement solution.

The commercial challenges addressed by the project has complemented the implementation of new commercial arrangements being driven by the wider industry, such as the trial in relation to how the Statement of Works process is undertaken when distribution projects are considered to impact transmission. Delivery of a new commercial arrangement within the current BEGA/BELLA provision has also allowed distribution connections to realise transmission network access as part of an ANM scheme and which should be able to be implemented across other licenced distribution networks subject to transmission constraint.

The two-stage agreement has been implemented to accelerate the connection of five projects now under Dunbar GSP.

The project has also delivered solutions that permit connections that would otherwise be constrained as a consequence of transmission requirements by managing DG customers against an export limit at the interface set by National Grid under outage conditions through retrofitting ANM to an existing generator subject to an existing transmission overload protection scheme to maximum customer export opportunity.

The ARC project has informed wider industry discussions on the transmission/distribution interface, relevant even more so today as the penetration of DG continues to grow across the UK and which is now complemented by the increase in connection applications relating to energy storage and a range of Low Carbon Technologies. Activity undertaken as part of the ARC project has contributed significantly to National Grid publishing a guidance note on ANM as part of its annual SOF.

SP Energy Networks also chaired the ENA ANM Working Group from 2013 – 2015 which was responsible for the publication of the ANM Good Practice Guide in 2015 and the team continued to support the ENA working group with industry colleagues to enable learning from ARC to be used as a source of information when dealing with future ANM Transmission/Distribution interface arrangements.

Interaction with the SO brought forward many of the issues now the focus of wider industry debate around the role of a future Distribution System Operator (DSO). We demonstrated the ability of the DNO to implement control managing power flow across the transmission/distribution boundary during the ARC project, helping provide the balance between improved, lower cost system operation and end customer access to the existing grid to realise connection to the network and how this could overall benefit the economics of customer projects. This has helped inform customers as to whether interim or enduring ANM connections are feasible for accelerating their project.

Proving that the commercial and technical innovation demonstrated through the ARC project is not location specific and can be readily applied by other DNOs, we have already engaged with the SO to extend the concept of a fixed export limit through GSP transformers at three other sites in the SP Distribution licence area. As part of our SP Energy Networks DSO Vision paper published during 2016, we also identified North Wales and Dumfries & Galloway, part of our electricity franchise areas of Manweb and SP Distribution respectively, as areas of our network where we plan to implement and rollout our DSO Vision and which will rely heavily upon the learning and activity that has been delivered through the ARC project to date.

The T-D interface challenge has been central to the ARC project. We have learned a great deal about the interface between the transmission and distribution network, complexities and considerations that have to be addressed around system balancing, supported a number of wider industry initiatives and informed debate around implementation of ANM and its effect upon the transmission system, making significant progress towards a more flexible distribution network with potential for a local and regional DSO. Going forward we will continue to work with the SO and UK DNOs to share more information and set transparent rules regarding responsibilities for network operation and how network access continues to be facilitated to the benefit of all. To facilitate this, we will need all of the technical tools discussed in Report 1 at our disposal. However, as DNOs and wider industry participants explore the benefits in creating DSOs, the more significant challenge in the short-term will not be solely technical, but will be rooted in the commercial and existing cultural implications of change. The priority however will always be in ensuring that all parties are sufficiently incentivised and obligated in a way that benefits all energy users, customers and the wider energy system.

2. Introduction

The Accelerating Renewable Connections (ARC) project was a four year project that concluded at the end of December 2016. The project was successful in securing funding in the 2012 competition of the Low Carbon Network Fund. Building on previous projects, which had demonstrated the technical and commercial feasibility of managed connections and alternative connection arrangements within constrained distribution networks, the ARC project set out to deliver new use cases that tackled the interaction of Distributed Generation (DG) with the GB transmission system, empower customers through customer service innovations, and deliver a business case and business model information to allow any Distribution Network Operator (DNO) to adopt the same innovations.

The trial area focused on East Lothian and the Scottish borders. It is a mainly rural area with a number of market towns forming hubs of population. There are few large load sites although some of the towns have manufacturing facilities, including a cement plant which provides a significant base demand at Dunbar. Existing generation already exists in the area in the form of an existing Nuclear Power Station and a number of early embedded renewable projects have already connected at distribution. The area has a number of upland areas making it ideal for wind development but also has some of the highest solar irradiation levels in Scotland making it attractive for PV development. A large portion of the Scottish Borders network was substantially rebuilt following storms in 2001. Generally the network in the ARC trial area is a mix of overhead lines and underground cables serving a customer base of approximately 77,000. There is approximately 300 MW of connected renewable generation connected in this area, although this is likely a conservative estimate due to G83 PV connections that are not visible on our systems as a consequence of the DNO not being informed as required.

The Learning Outcomes from the ARC project have been summarised into three independent but inter-related reports:

1. Designing and Operating New Alternative Connection Solutions Across Voltage Levels
2. The Changing Nature of the T-D Boundary
3. The Business Case for Top Down Investment in Smart Solutions

Each report has been written to allow a range of stakeholders to be able to understand and consider adoption of the various technical and commercial approaches trialled through the project.

This is the second report in a series of three and which focuses on the commercial aspects of the project and the sphere of control between transmission and distribution network operators. It provides background context to the industry-wide shift towards managed connections and increasing flexibility. The rapid increase of DG has led to substantial changes to the way in which distribution and transmission networks operate. A similar shift is required in the commercial arrangements and industry processes that define the roles and relationships between stakeholders that own, operate, or use the network such that increased flexibility can be translated into overall customer benefits.

The boundary between the transmission and distribution network is one of the most important areas going forward. While the technical solutions pass information or control signals across the boundary, it is the supporting grid codes, commercial arrangements, licence obligations, and regulatory incentives that must evolve to ensure the best solution for the wider energy system. The technical issues at the boundary can include reverse power flows, voltage support, fault level mitigation and wider system balancing services. The often differing roles, technical approaches, and commercial motivations of transmission and distribution network or system operators can lead to unintended delays or costs to customers or inefficient use of the existing network. In this report we have brought a number of these issues to light and discuss how the ARC project addressed them where possible. We also discuss the impact of the ARC project on publication of our own Distribution System Operator (DSO) Vision paper and wider industry thinking and how the solutions trialled relate to the emerging DSO role.

As managed connections are rolled out to benefit customers with quicker and more efficient connections this has to be managed against the risk that the avoidance or deferral of network reinforcement in the short-term then fails to trigger necessary reinforcement in future. Some previous innovation projects funded by Ofgem[2] identified this risk and studied potential investment models for distribution reinforcements. The ARC project set out to implement and inform on the commercial arrangements required in order to ensure the investment signal is never lost for transmission works.

The report introduces the problem of the 'Exporting GSP' and challenges experienced at the T-D boundary. This includes reference to the current Statement of Works (SoW) process as well as the mechanism for DNOs to include costs and timescales of transmission reinforcement into connection offers. It then goes on to discuss the technical and commercial issues that were explored and trialled during the ARC project. The report continues by discussing the relevance of the ARC project on developments in the wider industry before concluding with a discussion on the next steps for the tools, techniques and approaches developed during the ARC project.

We have tried to make the report specific to the ARC project and avoid, where possible, generic examples of potential issues. We have tried to explain the issues in sufficient detail that allows broader stakeholders to access the information provided.

[2] UK Power Networks Flexible Plug and Play and SHEPD's Orkney ANM scheme

3. The Exporting Grid Supply Point

3.1. Background

Traditionally, distribution networks have been designed in a fit and forget manner where risk of network overload is designed out at conception and the network constructed to service all customers under both intact and N-1 conditions. Under the traditional network model power was assumed to flow in a top down direction, from transmission to distribution to end customers, and generation took the form of large, centralised, transmission connected power plants. More than a decade's worth of change in the energy industry towards increased distributed renewable electricity generation and storage has disrupted this model indefinitely. Whilst the existing 'fit and forget' has model remained economic for the first wave of renewable generation projects, the UK is now at a point where the continuation of a similar approach is neither feasible nor affordable.

The shift towards decentralised energy generation and storage is driving distribution networks to evolve to become more active in order to accommodate bi-directional flows, responsive demands, energy storage, and other emerging disruptive technologies that will become more and more present behind the traditional distribution-customer boundary of the energy meter. The low carbon transition has prompted DNOs to begin offering managed connections alongside traditional connections in areas of network deemed to be constrained in order to provide customers with network access that will either defer or avoid expensive and lengthy reinforcement upgrades. By managing the export of certain customers in real-time, in response to specific network constraints, the level of utilisation of existing network capacity can be maximised allowing for more efficient use of the existing network.

The UK energy regulator, Ofgem, has supported a number of innovation projects involving managed connections since the inception of the Low Carbon Network Fund. Today, all DNOs are moving towards issuing managed connections as a business as usual connection arrangement and indeed SP Energy Networks have, as part of their Incentive around Customer Engagement (ICE) plan, included the right for all customers to request an alternative connection solution and which is supported by the production of SPEN's own Flexible Connections and Principles of Access Policy. The foundation of both of these developments has been the implementation of learning drawn from the ARC project.

This activity should result in a greater volume of actively managed assets operating across distribution voltages, however with increased levels of connected capacity, this will ultimately lead to further impacts on network power flows at a national transmission level. The regulator continues to encourage DNOs to offer managed connections as a key means of delivering quicker and more efficient connections[3] as well as improving the overall customer service offering. This will support the continued growth of DG, which has already led to Grid Supply Points (GSPs), the point on the

[3] https://www.ofgem.gov.uk/publications-and-updates/quicker-and-more-efficient-connections-update-industry-progress

network which sees an exchange of power between distribution and transmission, to become exporting boundaries i.e. power is flowing from distribution to transmission level voltages.

Whilst managed connections can provide a means of delivering connections for customers more quickly, and at a lower initial capital cost than conventional connections, they should not mask the need for network reinforcement, nor the increase in day to day operating costs for the network operators in providing such alternative solutions.

Transmission network reinforcement requires sufficient evidence of a needs case. The timescales for DG planning and construction can often be misaligned, and typically shorter than transmission upgrades, which in most cases can span many years. Actively managed connections provide a means of accelerating connections but also provide the foundation and evidence required to support the business case for triggering wider network reinforcements.

The way in which the wider energy system is operated is changing and a number of challenges have been identified by the System Operator (SO), National Grid, in recent years. These include increasing constraint costs, reducing system inertia and the network in general operating at a higher voltage level. In many cases the time and cost to implement transmission solutions are prohibitive and the more economic and practical solution is for the SO to work more closely with existing network connected customers and the DNOs to address wider network problems.

The ARC project set out to investigate the challenges of the exporting GSP. The project started by looking at the case study of the GSP transformers being the technical constraint by which new DG could be managed against. Early in the project it was recognised that any ANM solution would require engagement and agreement from the SO and Transmission Operator (TO) to implement. However, the complex nature of different connection contracts, regulatory incentives, and licence obligations as well as industry codes meant other issues of system and market operation quickly came to the fore.

To study the case of an exporting GSP, the ARC project focused on Dunbar 132/33kV Grid Supply Point. We investigated a way of providing the SO with enhanced visibility of connected DG and explored the operation of an Active Network Management (ANM) scheme to facilitate new managed connections.

Visibility of generation embedded within the distribution network becomes very important to the SO as the volume of DG and future DER assets increases. The SO models and operates the system based on flows at the GSP and other boundaries across the transmission network. As the GSP flows become less predictable, and the comparative volume of synchronous transmission connected generation decreases, the volatility of the system will increase and will therefore be harder to manage without visibility of activity within regional distribution networks. It is under this scenario that actions at distribution level begin to have significant impact on wider system operation and in particular, balancing of the transmission system. It is important to further develop the relationship between SO and DNO. Currently the SO has a role in planning what reinforcement takes place and delivered by the three GB TOs. Therefore by increasing information flows between SO and DNO, the issue of transmission constraints could be resolved more effectively and efficiently.

During the course of the ARC project, the wider electricity industry recognised the growth of ANM and the impact it would have on wider system operation. Both Ofgem and National Grid published documents which made reference to the increase in DG and the impact this could have on both the transmission and distribution networks in the short and longer term. Details of these documents are discussed in Section 6.

3.2. A Case Study Example: Dunbar Grid Supply Point

Dunbar GSP was already an exporting GSP prior to the conception of the ARC project. With 110 MW of distributed generation already connected with a maximum demand within the area recorded at 30 MVA, thus making it an 'Exporting GSP'.

The Dunbar ANM Scheme has proved to be an excellent trial site to demonstrate new innovative commercial and technical mechanisms under ARC for overcoming real-life examples of T/D interface constraints.

Prior to the commencement of the ARC project, three new consented projects approached SP Energy Networks seeking connection to the local distribution network and applied for connections totalling 50MW.

As a consequence of connecting 110MW of embedded wind generation throughout 2003-2008, a requirement for local transmission network reinforcement for any further parties wishing to connect was identified via the Statement of Works process, with transmission reinforcement costs estimated at £20 million with a connection date of 2021 following completion of identified transmission works.

The reason that SP Energy Networks chose to trial the implementation of an Active Network Management (ANM) scheme at the Dunbar GSP was for three reasons.

1. Accelerate the connection of additional distributed generation projects onto a constrained network.
2. Prove that there was sufficient capacity within the existing network to accommodate an increased connected capacity of intermittent generation;
3. Existing generation already had in place an overload protection scheme;
4. Trial the management of a large embedded generator under intact and outage conditions through delivery of an Active Network Management scheme.

In addition to the implementation of ANM to facilitate further generation, the project also retrofitted an ANM control system at an existing 48MW generator to permit additional export in real-time against an actual measured network constraint, as opposed to a modelled constraint under traditional network modelling that was currently subject to connection through implementation of an overload protection scheme. The existing generator, a wind farm, had already connected under a BELLA contract and protection arrangement at the 33kV busbar. This meant that under outage conditions, such as the loss of one of the transformers at the GSP, the wind farm could receive a trip signal or for a planned outage an agreed export limit, to ensure that thermal limits of the remaining transformer would not be breached. During the ARC project we sought to prove that the addition of real-time control, facilitated through ANM, could have greater system and customer benefits and allow management of the generation export within existing network limits and which would operate within the parameter of the existing protection arrangements with the protection scheme remaining the ultimate network protection should a failure of the ANM system occur.

To enable the ARC project to deliver on its overall objectives and install ANM at Dunbar GSP, discussions were required with the SO and incumbent TO, SP Transmission. We engaged in a series of meetings with the SO that required the visit of the ARC team and project partners to NGET's offices at Warwick and Wokingham. Early engagement with a variety of NGET stakeholders from Network Planners, Operational staff, as well as the Commercial and Customer management teams allowed for an open forum with the aim of assisting them to gain a clear and transparent understanding of the technology that would be deployed.

Part of this engagement involved the completion of power flow studies at Dunbar GSP to understand how the network would operate under both system intact and outage conditions currently and post implementation of ANM. This was used as evidence to demonstrate the advantages of ANM to the SO and both existing and future distributed generation developers. Following engagement, undertaken throughout much of the early part of the project, the SO & TO both agreed to permit the implementation of an ANM solution at Dunbar, this then allowed SP Distribution to offer ANM connections to initially three new renewable developers that had come forward in the Dunbar area and allowed the output of the existing wind farm generator to be actively managed during network system outages.

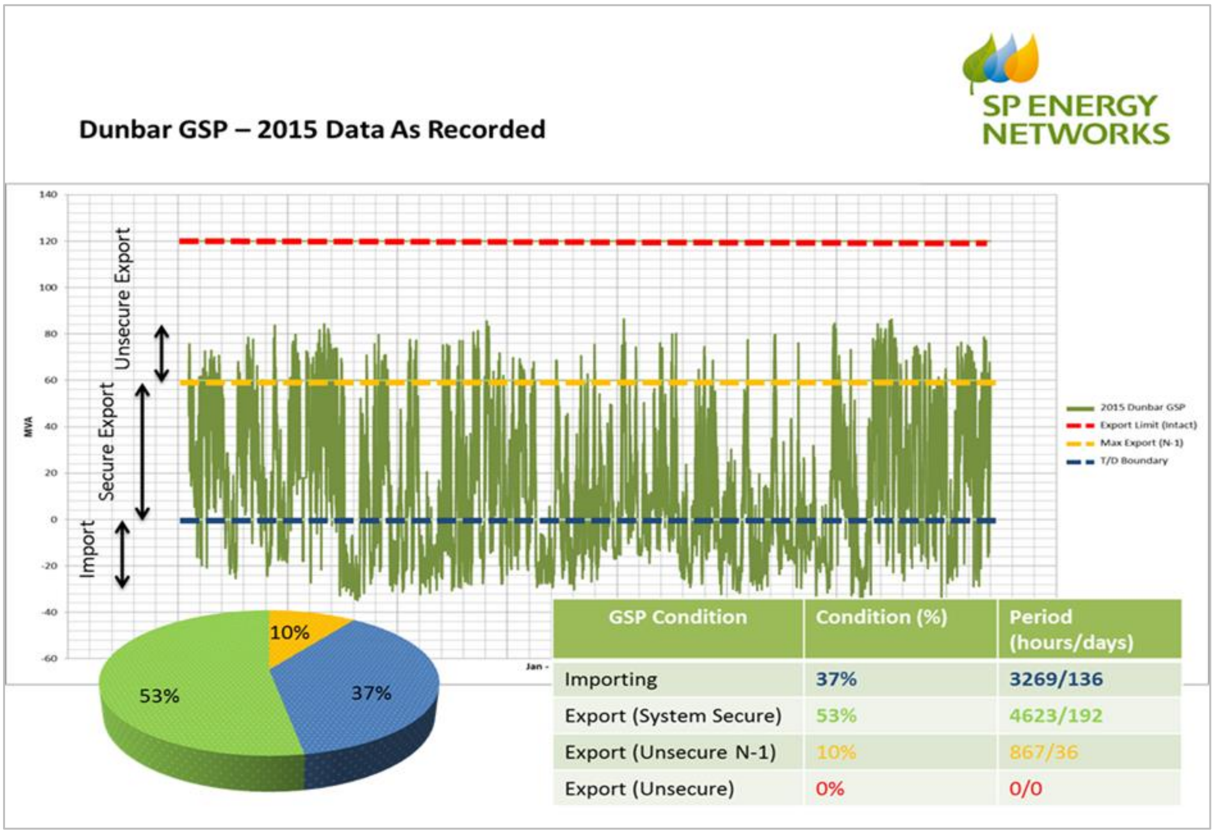


Figure 2: Dunbar GSP Profile 2015

Figure 2 details the performance of the Dunbar GSP network in its current state over the calendar year 2015. This data represents the system with only existing generation connected to the network pre-ARC (~110MW). Data shows that for **37%** of the year Dunbar GSP imports energy across the transmission/distribution boundary. However, due to the size of existing generation and variable demand within the Grid, **63%** of the time Dunbar GSP exports energy to the 132kV transmission system, i.e. the level of electricity generation connected to the distribution system outweighs that of local system demand.

In recognising the high percentage of reverse power flow at Dunbar GSP, data suggested that for **10%** of the year the level of reverse power flow exceeds the capacity of the system under an N-1 condition, i.e. Loss of 132kV circuit or Grid Transformer. Therefore if unmanaged would pose a risk of overload arising on the remaining grid transformer during any N-1 outage or fault, hence the second generator to connect prior to the commencement of ARC was commissioned subject to a ‘connect and manage’ overload protection scheme, as identified in Figure 3.

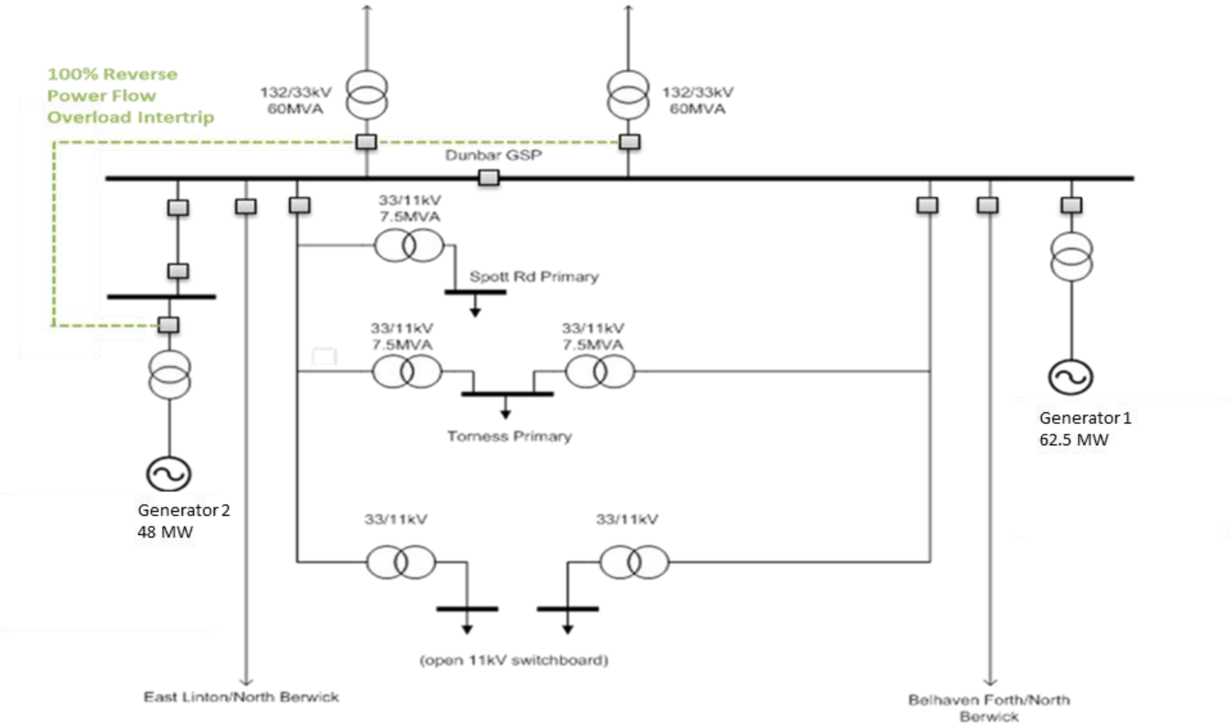
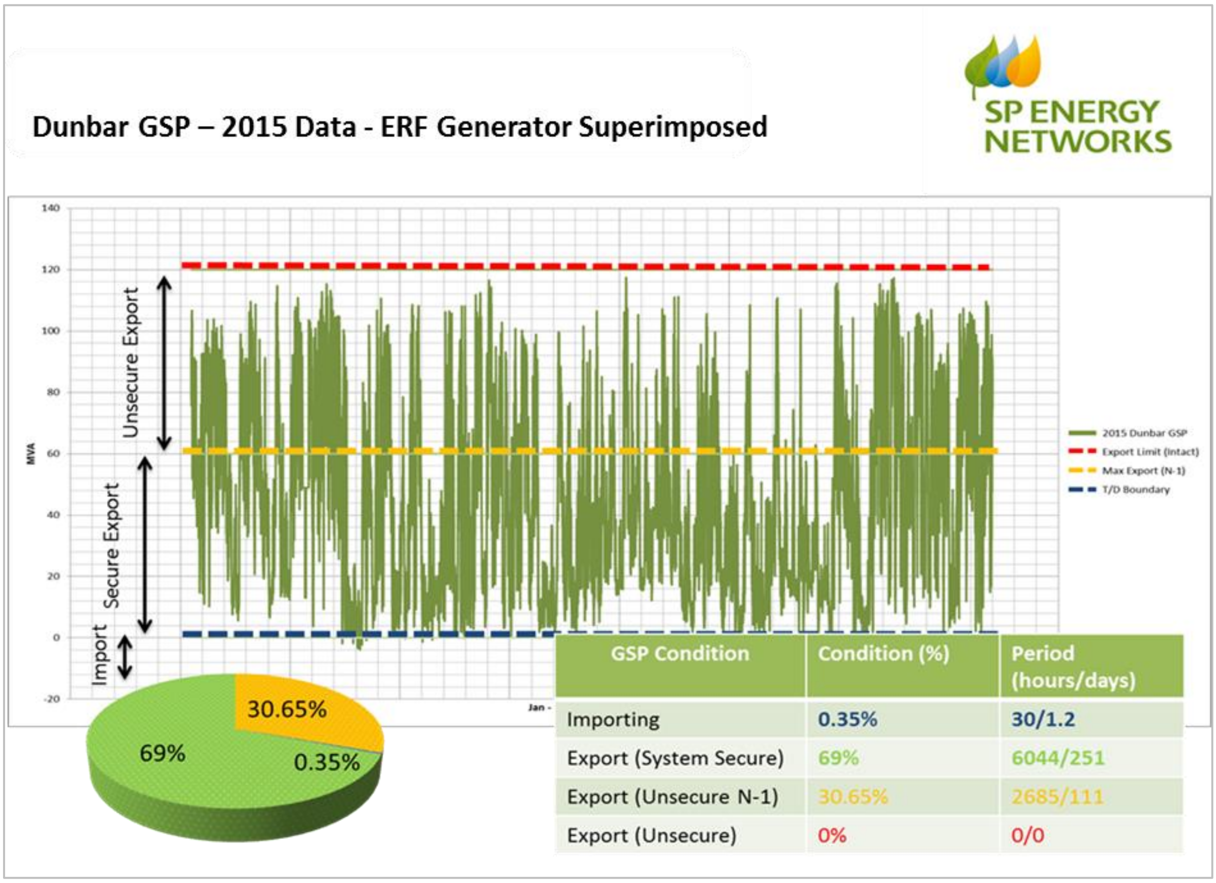


Figure 3: Dunbar GSP Network Pre ARC

At the commencement of the ARC Project, analysis was undertaken to better understand how the behaviour of Dunbar GSP would change once a number of additional large generators connected to the system under an ANM connection. Forecast export with a superimposed data set from an Energy Recovery Facility (ERF) generator identified significant change in GSP behaviour, detailed in Figure 4;



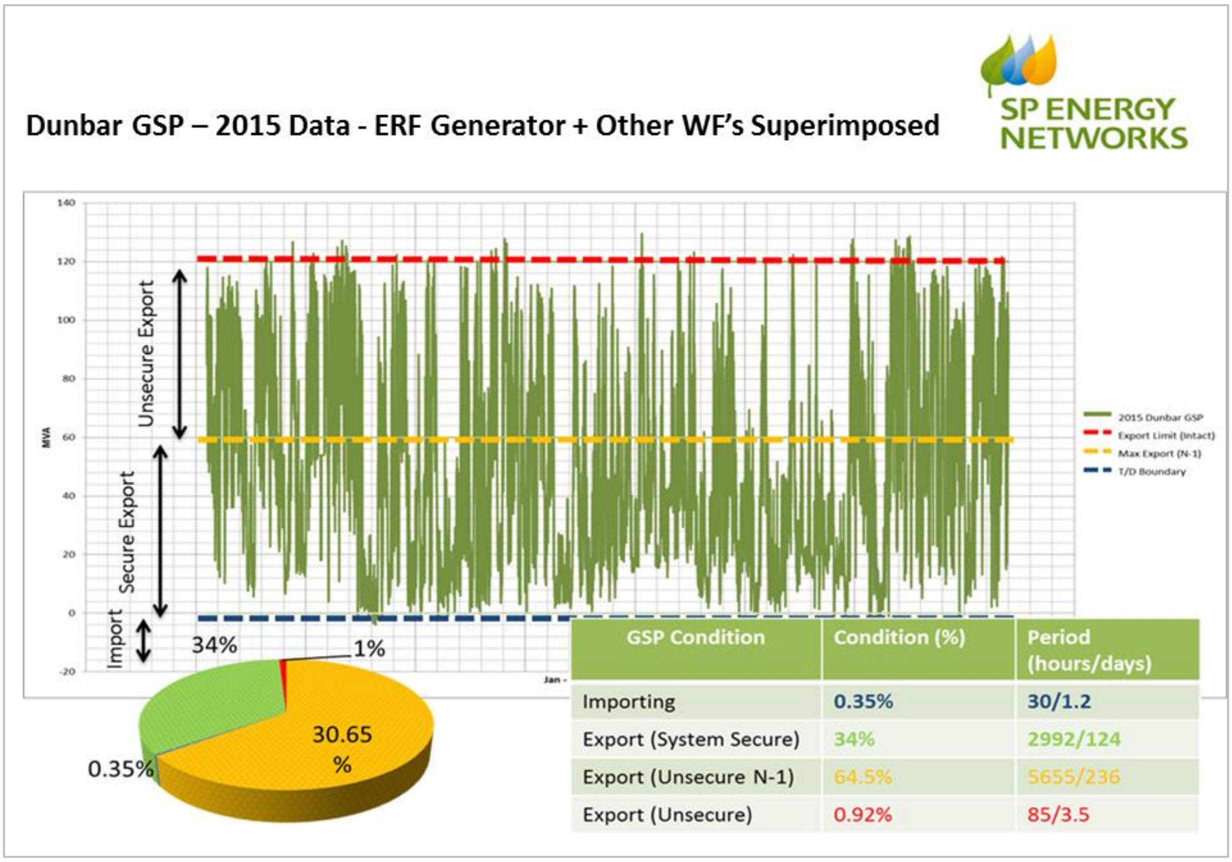
GSP Condition	Condition (%)	Period (hours/days)
Importing	0.35%	30/1.2
Export (System Secure)	69%	6044/251
Export (Unsecure N-1)	30.65%	2685/111
Export (Unsecure)	0%	0/0

Figure 4: Anticipated Profile at Dunbar GSP with ERF Generator Connected

The performance of the Dunbar GSP network with an ERF Generator connected under an ANM connection creates a GSP that for **0.35%** (~1 day per annum) imports energy from the transmission system. Meaning that for **99.65%** (~364 days or per annum), Dunbar GSP will become a net power exporter.

With a higher percentage of reverse power flow at Dunbar GSP caused by the connection of an ERF generator, data suggests that the previous **10%** of the year when the level of reverse power flow exceeds the capacity of the system under an N-1 condition, i.e. Loss of 132kV circuit or Grid Transformer, changes to approx. **30%**. Therefore, again if left unmanaged would pose a risk of overload arising on the remaining grid transformer during any N-1 periods. The solution implemented under ARC was the connection of an ERF Generator onto an Active Network Management connection.

However, the ERF generator was not the only consented project wishing to connect under Dunbar GSP and therefore further analysis was undertaken to better understand the expected GSP behaviour if all customers were permitted to connect under an ANM scheme. Results of which are details in figure 5;



GSP Condition	Condition (%)	Period (hours/days)
Importing	0.35%	30/1.2
Export (System Secure)	34%	2992/124
Export (Unsecure N-1)	64.5%	5655/236
Export (Unsecure)	0.92%	85/3.5

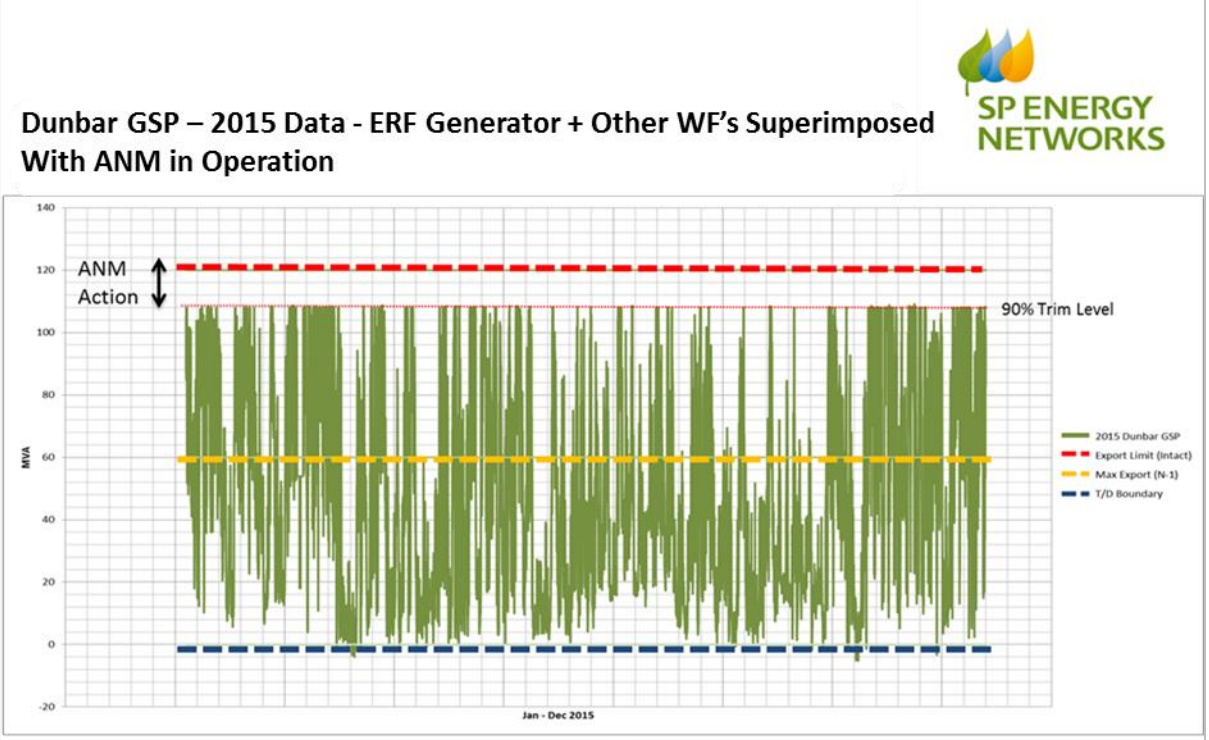
Figure 5: Anticipated Profile at Dunbar GSP with all ANM Generators Connected

The forecasted export across the transmission/distribution boundary when all of the additional 50MW of generation connects under ANM control takes the GSP from a site whereby thermal constraints only arise under N-1 conditions, to a GSP that will witness reverse power flow limits being breached under system intact conditions. In the absence of ANM control, even with the implementation of the existing overload protection scheme, the frequency and probability of generator disconnection becomes an operational challenge for both the customer but also the incumbent transmission operator, SP Transmission.

The performance of Dunbar GSP network with the ERF Generator and all other consented wind farm projects connected under an ANM connection creates a GSP with an import that remains at **0.35%** (~1 day per year). However, levels of reverse power flow increase whereby **64.5%** of the year reverse power flow exceeds the capacity of the system under an N-1 condition, i.e. Loss of 132kV circuit or Grid Transformer, equivalent of 236 days. Furthermore, for **0.92%** (~3.5 days per year), constraints appear even with an intact system i.e. both Grid transformers operating at the limit of the reverse power flow rating, further justification that the network operator requires to take active control over generators feeding into this GSP constraint.

However, It is recognised that in order to provide sufficient time for the generators under ANM control to respond to a curtailment instruction, a period of time must be allowed for a curtailment instruction to be dispatched, received and actioned under ANM. Also each generator will have differing characteristics regarding ramp-down rates, therefore a **90%** limit was set whereby upon a threshold being breached any embedded generator feeding into the constraint would be asked to reduce active power export in accordance with each customers position in the commercially defined merit of order, known as Last in First Off (LIFO).

The setting of a **90%** trim threshold does however reduce the amount of capacity permitted to generate into the grid constant and when considered against the expected Dunbar GSP operational behaviour once all ANM connected parties are commissioned, takes the level of constraint from an previously estimated **0.92%** as detailed in Figure 5, to a constraint period of **5.94%,** equating to a curtailment period per annum of 520 hours (~22 Days), shown in Figure 6 below;



	Dunbar GSP ANM
Curtailment Period %	**5.94%**
Curtailment Period (Hours)	**520**

Figure 6: Anticipated Profile at Dunbar GSP with all ANM Generators Connected at 90% Trim Limit

Given the new level of constraint identified with a 90% trim threshold, as well as future unpredictability around existing network load from a large 33kV demand customer, a decision was made to introduce a staged connection agreement triggering longer term GSP transmission network upgrades expected to be delivered by 2021 to mitigate all ANM customers against enduring constraint instructions.

3.3. The Connection Process and Statement of Works

When the developer makes an application to the DNO, who has a licence obligation to provide a connection quotation within a specified period of time, the process to identify any associated transmission reinforcement works, costs and timescales follows a different process, and which is only triggered on acceptance of an offer. The process, known as the Statement of Works (SoW), can be a confusing, time consuming and difficult one for customers, especially those only connecting one generation project in their lifetime.

When a developer applies for connection to the distribution network, the DNO studies the impact of the connection on the local network and provides an offer to the customer on the basis of necessary sole use assets and any wider distribution network reinforcements. The timescale for connection reflects the time to complete these distribution works; however the connection offer will, in certain heavily congested DG areas, also make reference to the connection being subject to a SoW and which will require an assessment by the incumbent TO which is coordinated and managed through applying to the GB System Operator National Grid. The development of the connection offer from the DNO to the customer is governed by the distribution electricity license of the DNO, the SoW process however does involve the customer paying an application fee and which adds significant period of time for completion of the full offer from the SO. The result of the SoW process may be confirmation that no transmission reinforcement is required or may result in identification of significant transmission reinforcement costs or subject to existing or already planned wider reinforcement works being completed. The result of all this activity means however that the overall time to realise a connection to the network can be delayed or in the case of a significant number of distributed generation projects, never proceed.

One further issue to highlight is that under the current connection process, when a customer requests a generation connection to the distribution network, they can exercise choice on whether to seek a 'firm' connection to the distribution network, whereby redundancy would be built into the network to ensure that no interruption to site export would be experienced for a fault or single network outage. Or, as is common practise with the majority of new embedded generation projects, a 'non-firm' connection to the distribution network, whereby upon fault or single network outage the generation asset no longer has access to the network to export power. Example as shown in Figure 8;

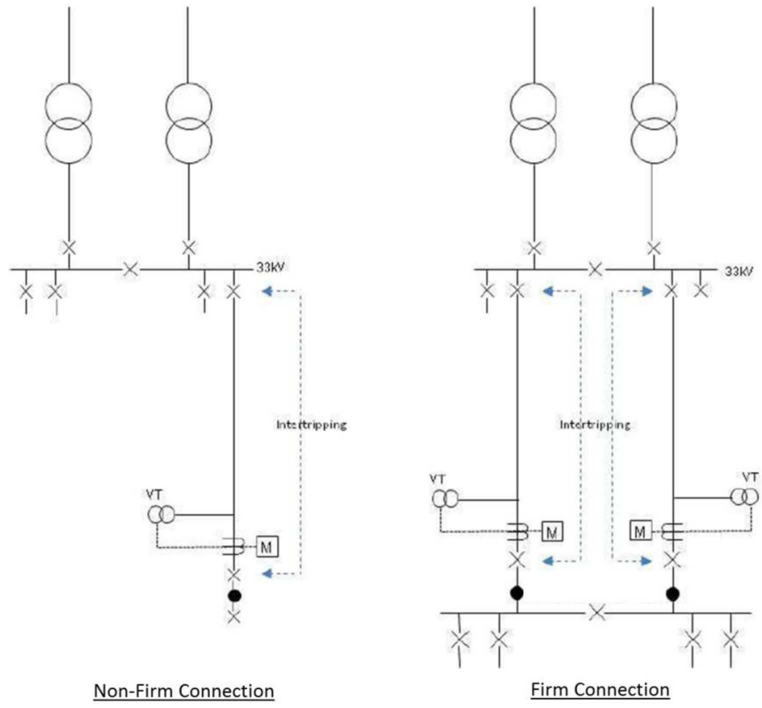


Figure 7: Non-Firm and Firm Generic Connection Arrangements

Traditionally, when a distribution generation connection is considered to impact the transmission system, the customer would have had no choice than to receive a connection offer via a SoW process which requires that the project be designed as 'firm' against the transmission network assets. This means that at all times the customer would in theory be able to export onto the transmission system the maximum installed capacity of the development 24/7, 365 day per year, even during N-1 conditions. This requirement is embedded within the existing design regulations and standards such as SQSS which govern the execution and delivery of design requirements on the transmission system. Again as part of the project we have sought to challenge these design requirements with the advent of greater control and flexibility of generation assets through implementation of ANM and recognising that in reality, wind farms, PV arrays and other generating technologies do not operate at full capacity for large proportions of the year. A typical wind farm may have an annual capacity factor ranging from 35-45% and indeed PV may have an annual capacity factor of between 10-15%, however it is recognised that these will vary across the country.

In many cases, transmission reinforcement costs, along with transmission connection securities and liabilities can be prohibitive for the developer and will ultimately stop the project from continuing. This is particularly true for small developers (sub 5MW) trying to connect in areas of the network with significant transmission constraints.

The SoW process can be triggered automatically by the size of the connection. For example, in some areas of the UK this is triggered at 50MW however in other areas of the network, such as parts of Scotland, due to existing levels of connected DG, this trigger is now at a very small scale and can include G83/2 and G59 connection applications. As the energy sector continues to decentralised power generation the SoW process will likely require evolving to continue to be efficient and meet the needs of small scale distribution customers.

3.4. Limitations of Available Contractual Instruments

For larger embedded generators, there are a number of contracts used to define a generators relationship with the transmission network. These are explained in more detail in the sections below. These contractual arrangements were developed at the introduction of a single UK wide energy trading market (BETTA) in April 2005. However, since its introduction and as a result of significant change in the volume of embedded generation connections under ROC and FiT incentives, such contractual arrangements present limitations for a future system of increased flexibility and customer choice at a distributed level.

3.4.1. BEGA

The **B**ilateral **E**mbedded **G**eneration **A**greement (BEGA) states how generators connecting to the distribution network must comply with the:

- ✓ Grid Code;
- ✓ Connection and Use of System Code (CUSC); and
- ✓ Balancing and Settlement Code (BSC).

The BEGA is for large generators (for example, 30 MW or greater in the SP Distribution licence area) which provides the customer with Transmission Entry Capacity (TEC) as the customer will have the right to operate in the balancing market and export to the National Electricity Transmission System (NETS). The implication being that the transmission network has been constructed to accept export from generation on a 'firm' basis with any constraint instructions issued compensated through the Balancing Mechanism.

The BEGA provides the same type of arrangement as a Bilateral Connection Agreement (BCA) for generators connecting directly to the transmission network.

BEGA arrangements allow National Grid as SO visibility of these generators on the distribution network, with a commercial mechanism to request control over them for system balancing (through the appropriate protocols and processes). However, visibility of any bi-lateral flows of information between the SO and the embedded generator remain unseen to the distribution network operator or any local ANM scheme, such as those at Dunbar and Berwick GSP.

3.4.2. BELLA

The **B**ilateral **E**mbedded **L**icence exemptible **L**arge power station **A**greement (BELLA) states how generators connecting to the distribution network must comply with the:

- ✓ Grid code; and
- ✓ CUSC.

The key difference between a BEGA and a BELLA arrangement is that the BELLA does not automatically give the generator the right to participate in the Balancing Mechanism or provide 'firm' access to export onto the transmission system. It is possible for a BELLA generator to participate in the Balancing Mechanism without an agreed transmission entry capacity, provided that they install the necessary communications infrastructure and have appropriate processes in place to respond to balancing instructions issued by the SO.

The BELLA also allows large generators to connect to the distribution network and benefit from a non-firm connection to the transmission network. They will likely be subject to a network protection scheme, whereby the SO/TO can remove the generator when required for either network constraints or system operational reasons. The generator however is not necessarily compensated for responding to those signals. While this can relieve constraints on the transmission network, it can have an adverse impact on distribution network operation – and in particular, can result in a zero net effect if an ANM or Demand Side Response (DSR) system is in place at distribution level operating in isolation from the activity of the SO in respect of balancing actions.

Another identified issue is that growth of smaller scale generation and future 'behind the meter' changes will increase the likelihood and frequency of any installed protection schemes from operating in future. Such 'hard' intervention serves a purpose of protecting network assets from exposure to harmful overload conditions but can also have a detrimental impact upon customers connected to such schemes without participation in alternatives means of providing 'Soft' intervention such as ANM control.

3.4.3. Restricted Access Agreement (RAA)

In recent years we have also seen the development and implementation of the Restricted Access Agreement (RAA) which is a temporary connection solution with National Grid (SO) that relies upon a hard intertrip or transmission implemented Load Management Scheme to facilitate early connection to the network. This agreement however still requires completion of transmission reinforcement works towards a 'firm' connection. A RAA allows the generator to gain early access to the network and make use of available latent capacity during periods of high demand/low generation but is not an enduring arrangement. Under a RAA the generator will eventually pay for their apportionment of transmission reinforcements and move to 'firm' transmission access. Similar to the BELLA generator, a RAA generator will likely be curtailed in most cases to zero export during a transmission constraint event in line with the customers 'nom-firm' connection rights to the network.

In the ARC trial area, there are no generators contracted under a RAA. However, as embedded generation and more recently DER (Storage, DSR, and STOR) continues to seek connection behind transmission/distribution boundaries across Scotland and the rest of the UK. The number of offered RAA contracts should reduce as more suitable alternative connection solutions such as ANM become available and adopted as Business as Usual, as discussed in more detail in section 4.4.4.

3.4.4. An Alternative Contractual Arrangement

Some of the existing contracts discussed above do create enduring solutions, typically in the form of reinforcements to the network. This is acceptable if the reinforcement costs are reasonable, and the developer can afford to upgrade the network as part of the connection costs. However, due to the increasing levels of constraints on the wider transmission network, and in particular the increase in the number of exporting GSPs during high wind conditions, a greater volume of reinforcement works are now required to reinstate a compliant SQSS transmission system under a non-managed arrangement. However, this is unlikely to be affordable for small and community scale developers wishing to connect at lower voltage distribution levels. This is particularly true in the ARC case at the Dunbar GSP.

At Dunbar GSP the effectiveness of the standard arrangements for gaining transmission access (BEGA, BELLA or RAA contracts) was explored. Changes in customer behaviour at 11kV/LV through further increased levels of DER and flexibility will further impact the transmission network and trigger the requirement for wider protection schemes as the only form of generation control, to facilitate an early connection. Greater coordination across the transmission and distribution boundary becomes the obvious next step. An ANM connection can accelerate early connection and based upon the existing circumstances of the network can be a staged offer or enduring connection for developers.

Several of the developers connecting to the Berwick GSP network, pre-ARC, were subject to a BEGA/BELLA connection arrangement with the SO as a means of early access under 'non-firm' transmission access. As part of the ARC project, each new developer was able to exercise choice and connect to the network through a staged 'non-firm' ANM connection, moving to firm transmission access following completion of necessary transmission network reinforcement. This enabled the developer to connect to the network, make full use of available capacity in real time and remove any obligation to provide system services to the SO. The commercial offering was two-stage connection agreement. Both developers, totalling ~60MW, have now signed up to this connection agreement and are now commissioned and operating successfully.

These agreements follow a similar format of the current BEGA/BELLA agreements with the SO; however the important difference is that the contract is between the customer and the DNO and that ANM is recognised as the key control methodology that will permit export to the network for various system scenarios. They do however still rely upon the implementation of network protection infrastructure which is developed in conjunction with the SO/TO, as detail below in figure 9;

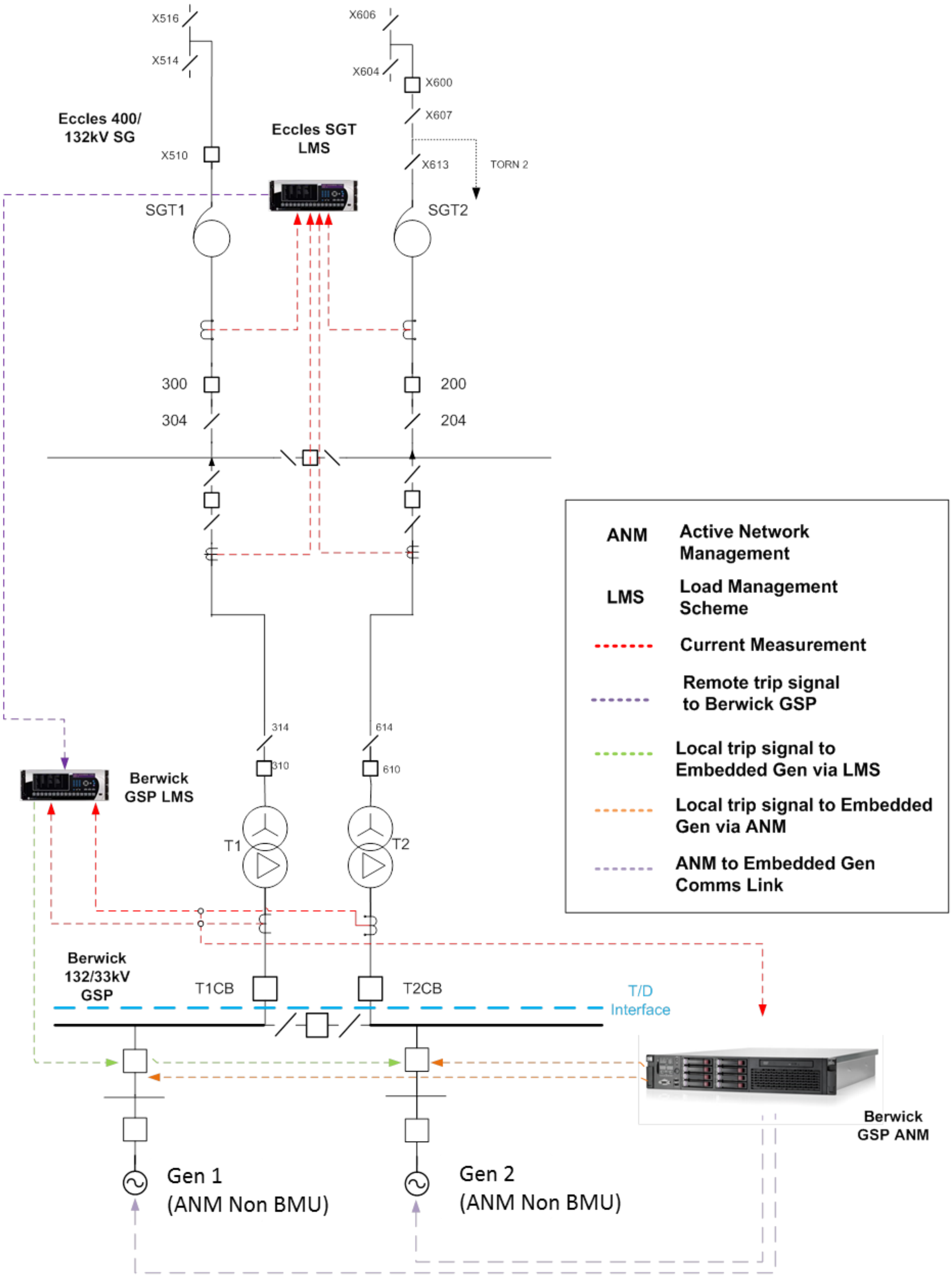


Figure 8: Eccles/Berwick GSP LMS & ANM Scheme

3.5. Wider System Issues

The growth of embedded generation and widespread adoption of managed connections on the distribution network is also creating new challenges for wider system operation such as power flow interactivity with the Balancing Mechanism and network outage management. Examples of these are described below.

Power Flow Interactivity with the BM: The SO can instruct a large embedded BM unit to reduce export in order to balance the network. This may be, for example, to reduce power flows across the T/D boundary, take planned outages on the wider system, or simply balance supply and demand. When export from the BM unit is reduced, this instruction can potentially release more headroom across the T/D interface. In the absence of a linkage between the actions of the SO and DNO ANM schemes, the ANM system will identify this headroom through the change in flow of current at the measurement point and allow any previously constrained generation to increase export to a suitable level within the new network limit. This has a net effect at the GSP of zero because ANM generation has filled the headroom created by the reduction in export from an embedded BM unit.

Network Outage Management: The SO plans outages in order to maintain and upgrade the transmission system. Often they request both BELLA or RAA customers to remove themselves first, thus removing any contributing power injection onto the system during the period of the outage, as per the terms of the connection agreement i.e. 'Non-firm' access against transmission. However, due to the penetration of small scale 11kV and LV connected generation now connected to local distribution networks across the UK, in some instances the SO may not have sufficient BELLA, RAA, or even, BEGA generation agreements available to mitigate against the risk of constraint within the section of network subject to N-1 outage conditions, resulting in potential delay or abandonment of transmission system upgrades.

These two examples above demonstrate that without greater coordination between transmission and distribution networks there will be a long term negative effect on system operation. This problem is not caused by ANM; it is a consequence of the existing processes and contractual mechanisms that define the interaction at the T-D boundary and the fact that each party does not have sufficient visibility of the others actions and the DG contribution to a relevant network constraint at a GSP level. This results in more pessimistic and inefficient actions being taken to manage the network that both increase costs and reduce the levels of generation that is exported from local renewable resources.

4. Demonstration of Technical and Commercial Innovations to Address the T/D Interface Challenge

4.1. Technical Solutions

This section provides a brief summary of the technical solutions demonstrated in the ARC project to address the problems described in the previous Report *1 - Designing and Operating New Alternative Connection Solutions across Voltage Levels* and provides a more detailed account of the solutions and which are summarised in this report to provide general context to the commercial solutions implemented.

4.1.1. Exporting GSPs Constrained at the T-D Boundary

The ANM system implemented at the exporting Dunbar GSP manages the output of all new DG connections based on measured current flows witnessed through the transmission operator's grid transformers. This is the first example of a working ANM solution to coordinate multiple DG against a transmission constraint in this way. The ANM system provides approximately 600ms near real-time control of the embedded generation against measured transmission network loading and provides increased and coordinated access to capacity, by maximising multiple generator export whilst maintaining customer's connection to the network.

4.1.2. Example of ANM and TO Protection Scheme

Prior to the commencement of the ARC project, an earlier generator in the Dunbar Network was granted early 'non-firm' access to the transmission system and as part of the connection agreement was commissioned subject to the implementation of an overload protection scheme to protect the remaining grid transformer during any planned or unplanned outage at Dunbar GSP.

In 2015, the Dunbar ANM scheme was retrospectively installed to operate within the limits of the existing overload protection scheme. Meaning that, under N-1 conditions the generator would be dynamically controlled via the ANM system rather than manually limited by the SPD control room.

Due to an unplanned 132kV fault in 2016, the ANM scheme was demonstrated to work in allowing the existing wind farm to continue to generate and export power under N-1 conditions without breaching the thermal limit of the remaining grid transformer or triggering the operation of the incumbent overload protection scheme. Figure 10 provides an example of a high wind, low demand period whereby the generator was instructed to curtail and successfully responded in near real time over a 5 hour period, with Orange representing the real-time output of the wind farm, Pink representing the ANM set-point and Grey representing the flattening in reverse power flow across the remaining in service Grid transformer.

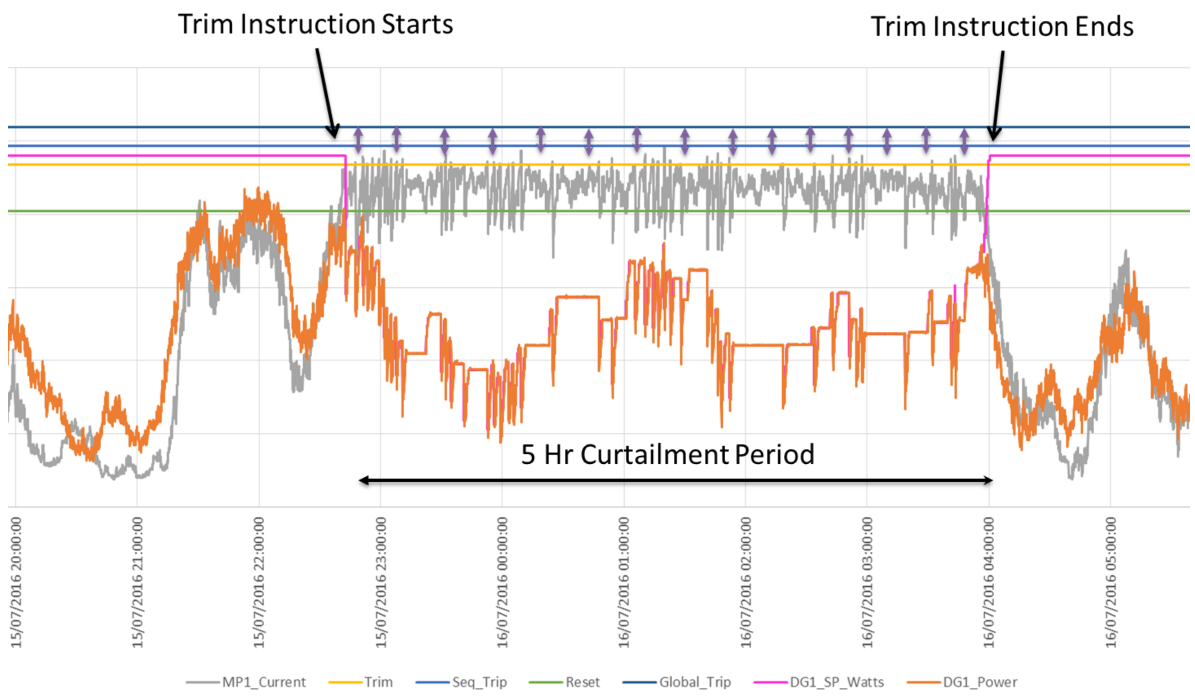


Figure 9: ANM Enabled Wind Farm Managed against Overload Intertrip Threshold

Learning from this unplanned 132kV outage in 2016 released significant benefit to the customer under ANM. The outage resulted in one of the Dunbar 132kV infeed circuits being out of service from 2nd June 2016, until its reinstatement in 2nd October 2016. Prior to the implementation of ANM control, standard operational practice would have been to limit the power export from the embedded generator with 'non-frim' transmission access to a level which kept the remaining grid transformer within operation limits.

The following table details the direct customer benefit from have ANM enablement during the fault event;

	Without ANM Control	**With ANM Control**
Peak Output (MW)	10	42 (+32)
Energy Generation Volume (MWh)	27,812	47,151 (+19,339)

Table 1: ANM CBA 2016 Fault Event

During the period of the outage, the project successfully demonstrated how the ANM can safely manage network loading in a post fault event without allowing the embedded generator to run into a condition whereby they would have been removed from the system under the transmission overload protection scheme previously commissioned as part of the connection agreement. In total, it is estimated that the customer received additional network access in the region of **19,339MWh** over a **4 month** period.

Figure 11 details the technical architecture of the scheme implemented at Dunbar GSP for the purposes of the 'Exporting GSP' case study.

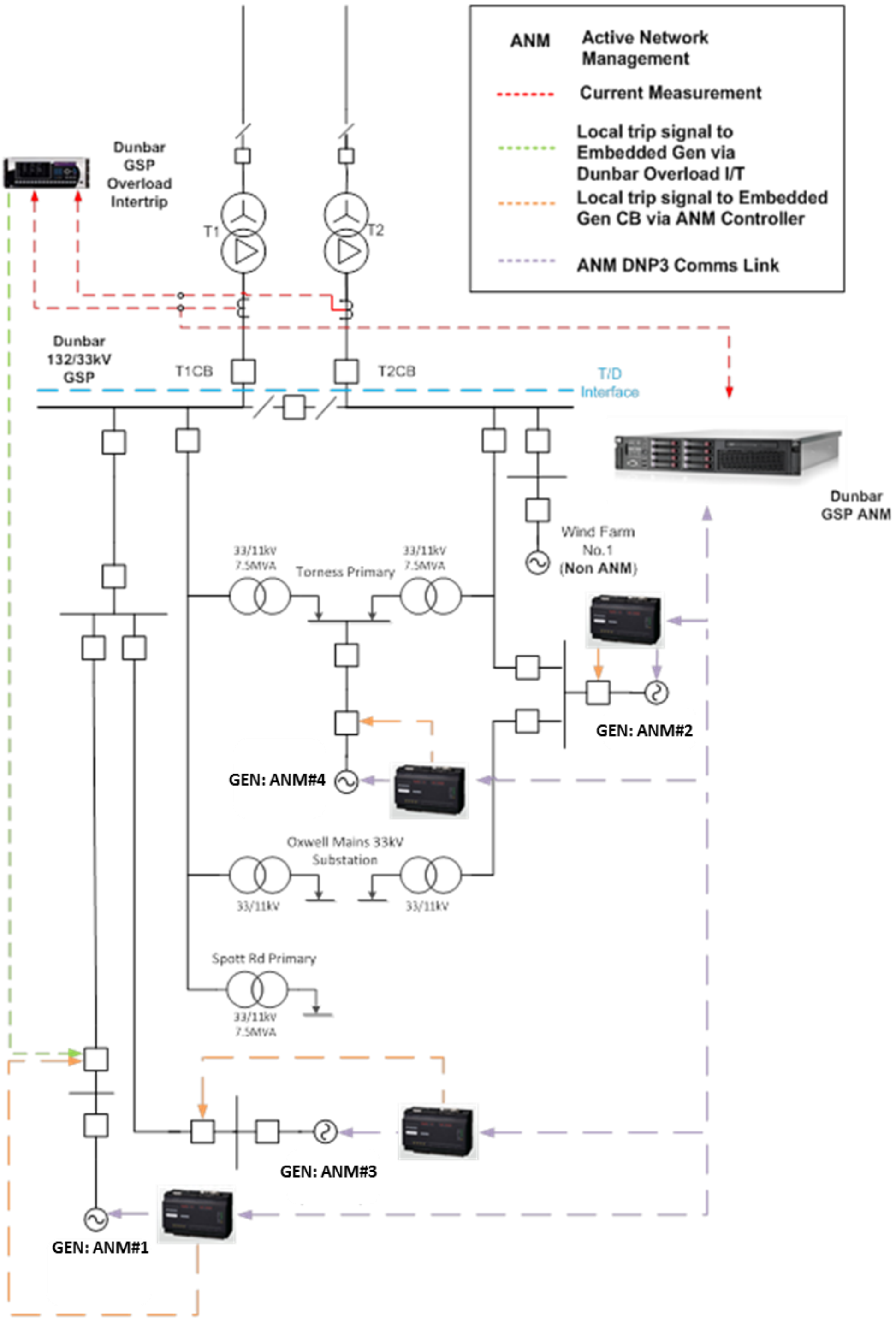


Figure 10: Dunbar GSP ANM Scheme Architecture

4.1.3. Future Technical Solutions to Resolve Combined ANM Intertripping Conflicts

Through innovation projects such as ARC, confidence within the industry has grown whereby the SO, TO's and DNO's recognise the added value that real-time control over embedded assets has in operating and managing a safe, reliable and economic network. However, further development around the technical interface at the T/D boundary is required and is underway within working groups such as the ENA's Open Networks Project.

An example of one such technical solution is detailed within Figure 12, whereby the DNO takes greater responsibility in managing transmission constraints using future Active Network Management schemes as a gateway between the distribution generation assets and the wider transmission network constraint.

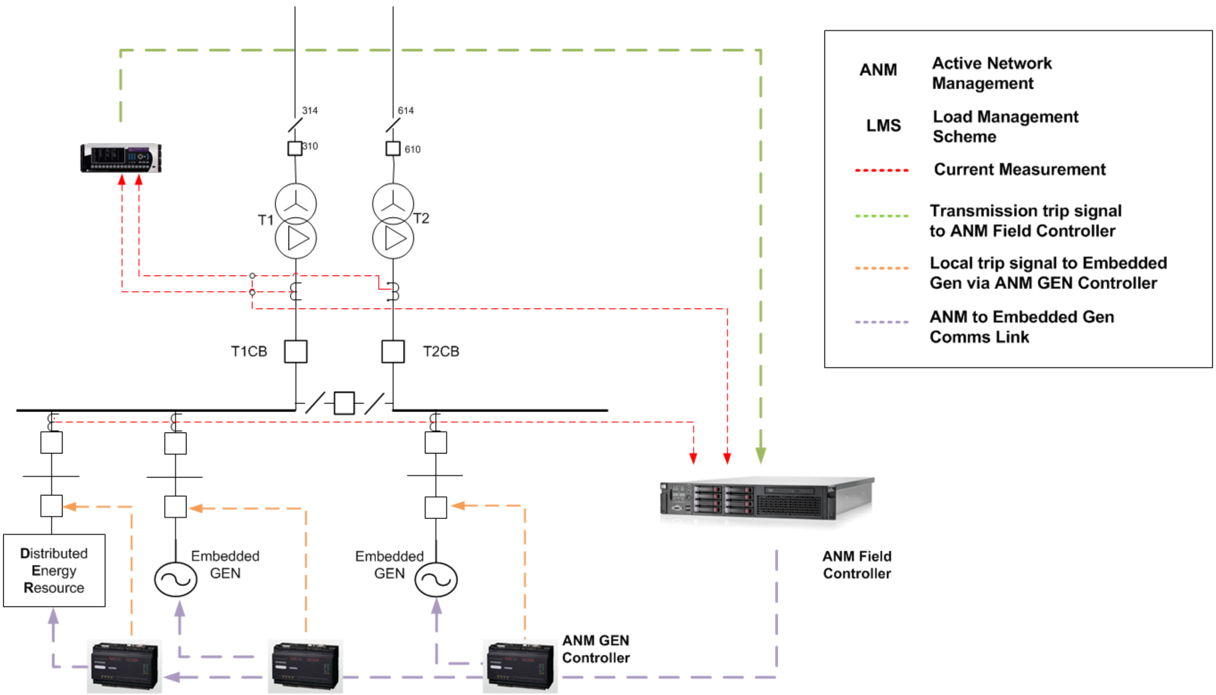


Figure 11: Potential Future Technical Architecture at T/D Interface

Such arrangements however do present challenges in coordination between ANM control and overcurrent protection schemes. The main challenge being the risk of interaction with existing overcurrent transformer protection settings commonly applied as a means of backup protection at the GSP.

The current methodology applied within the ARC Project is to use ANM control as a means of managing pre and post fault network load flows, with direct generator overcurrent protection implemented to protect the transmission assets during the first cycle of an unplanned outage event.

The main limitation of ANM control is that it does not operate within the same time parameters of current protection grade relay equipment and moving forward a requirement for a more advanced hybrid solution will be required.

4.2. Commercial Solutions

This section discusses the challenges of the SoW process, how network companies can provide customers with options for enduring or interim managed connections, and how the DNO provides the SO with a means of understanding how all generators within the exporting GSP area (including BM units) would be treated.

4.2.1. Two Stage Connection Agreement

During the ARC project, the Dunbar GSP Case Study and later Berwick GSP, was used to trial new control and commercial arrangements. In order to make the scheme commercially viable for the developers, at Dunbar GSP a two-stage connection agreement was developed.

Stage 1 of the contract is for 'non-firm' transmission access which is managed under the Dunbar ANM scheme. Generators pay for connection to the network during 2016 and are controlled by the ANM system in accordance with agreed principle of access (LIFO). Whilst at the same time, and as a parallel activity SP Distribution trigger the wider reinforcements to be undertaken at the transmission level with all contracting parties triggering the works contributing towards the upgrades on a pro-rata basis. For Dunbar GSP these works are scheduled to be completed by 2021. This allows generators to realise a connection to the network quicker and provides the necessary investment signals to proceed with the construction of network infrastructure at transmission level.

Stage 2 of the contract is for a 'firm' network access to the transmission network. Further to connecting to the network, it has been agreed with all connecting parties that the business case for transmission network reinforcement at Dunbar GSP and wider transmission system has been made to accommodate the proposed generation. This means that each connecting generator will be liable for their share of the costs to upgrade the Dunbar GSP and secure wider transmission upgrades during the course of construction. Stage 2 requires the generators to provide securities against their share of network capacity being realised by the wider reinforcement works. Generators benefit by gaining access to the network sooner and in doing so can supplement the capital outlay of the reinforcement work from revenue earned from being able to export under the Stage 1 ANM implemented scheme. The network operator benefits by having a clear and certain investment signal to deliver the required network reinforcement and do so in a manner which has been designed for the relevant load of generation that will ultimately connect.

It should be noted that implementation of ANM schemes across the networks are not a 'silver bullet' and that there are finite limits to the capacity which can be connected under any ANM connection. Typically based not on technical limitation but on the economics of a relevant connection as the level of forecasted curtailment of being part of the ANM scheme renders it uneconomic to proceed. At this point the level of curtailment will reach a state where a future developer will not make a suitable return on their investment. Network reinforcement therefore becomes the preferred and most economic option for the developer.

An example of the two stage contact is provided in the appendix A.

4.2.2. Consortium Agreements

At present, connection applications are in general processed on an individual basis whereby the minimum cost scheme for the customer is identified and assessed by the network planner. This approach is efficient in providing a robust connection option for a single generator, but can fail to identify opportunities for a more coordinated approach whereby connecting customers are grouped together to provide a more holistic solution. The reason for not doing this as standard practice is that proposed developments apply for connection on an individual basis and each connection application, is in the majority of cases, assessed as an individual development. Also developers themselves can be at an early stage and equally reluctant to engage with their fellow developers over future plans and development opportunities.

The ARC project allowed the demonstration of an innovative two-stage agreement to facilitate ANM as part of either a staged or enduring connection arrangement. In parallel with this new form of agreement was the process of forming a constructive working partnership with all key stakeholders and developers in order to develop the most efficient network solution. The benefit and acceleration of the connection of each site to the network has provided a robust investment signal for future transmission network reinforcements that formed Stage 2 of the connection agreement of the Dunbar ANM scheme. It must also be highlighted, that the ARC project also benefited from a diverse group of developers who recognised early in the process the benefits of working together and with the ARC project team, to facilitate their connections and who were very open and transparent with one another and SP Energy Networks as they developed each of their projects through the design, construction and eventually connection phase.

In the case of the Dunbar GSP, transmission reinforcement sole-use works are estimated to cost around £6 million, with each generator responsible for their apportionment of the costs based upon size of generation capacity being installed. All generators have worked together with each other and their respective financiers and investors to ensure transparency of their individual contribution and dependency on one another to ensure development of the works is clear. This coordinated approach has also realised additional cost benefits through improved delivery of connection works at distribution level by sharing of works, communications infrastructure or cable laying routes where possible.

More importantly however is that by working as a consortium, the reinforcement costs are being shared between them, meaning that all parties now have a viable project to proceed with. This is not always the case when smaller projects come forward initially on a piecemeal basis and are subject to high reinforcement works rendering their projects uneconomic to progress.

As part of the ARC project, SP Energy Networks provided and facilitated the collaboration between generators and enabled the process using the two-stage ANM contract. This approach provided coordination and certainty for the investment case for the benefit of all customers. A consortium approach, if implemented correctly, can provide customers with better connection options and avoid the piecemeal development of the network caused by the normal process of handling connection applications on an individual basis, however it must be recognised that such an approach requires generators who are willing to participate and the application of a significant resource and time on the part of the network operator to facilitate this dialogue and engagement.

4.2.3. Removing System Operator Barriers to ANM

The SO raised a number of concerns relating to the use of ANM within the trial area. It was only following a number of discussions between all stakeholders over a number of months during 2014 that the project gained traction to explore and resolve these issues, including:

- Increasing GSP and boundary flows from existing generators under outages
- Impact on BM actions and existing overload protection arrangements
- Operational/practical changes e.g. commissioning

Details of each of these considerations are given below.

Increasing GSP and boundary flows under outages

If there is an increase in capacity connected, it was assumed that this would increase the flows through the transformer onto the transmission network over and above its capacity rating – ultimately resulting in risking the assets and affecting boundary flow constraints. In reality, there is no more generation being exported on a thermal basis that can currently be exported when the existing generation is at its maximum export and the demand is at it minimal calculated level. Therefore by connecting a greater number of generators the net effect on transmission export limits is the same however by implementing ANM as the control methodology means the overall network is more efficiently utilised and new generators can make use of the latent capacity already inherent in the network to realise a quicker and more economic connection.

Impact on BM Actions and interface with existing overload protection arrangements

Legitimate concerns were raised by the SO about how the advent of ANM at Dunbar GSP may impact the wider operation of the transmission system, potentially creating an adverse effect on existing transmission connected generation and causing curtailment of their export for which the SO would require to compensate. Without a central coordinating party or gatekeeper between embedded generation and the SO, such as a Distribution System Operator (DSO), it will always be difficult and inefficient to implement solutions that transcend the transmission-distribution boundary.

One of the main issues that arose with SO system planners was the assumption that a greater penetration of generation capacity connecting behind an ANM scheme at a distribution level would cause an excess of generation that the existing system could not cope with. It therefore had to be explained that the advent of ANM controlled generation would only make use of the latent capacity within the existing network infrastructure. The issuing of curtailment or export capacity instructions would maximise the efficiency of the existing network in line with its current design parameters and limits and would respond in real-time to ensure that existing generators were not adversely impacted when their generation projects, on those few occasion in the year, sought to export the maximum rated capacity of their installed plant.

Creation of an ANM scheme provides the DNO with visibility of connected generation and its export activity at a distribution level in real-time, something that has not been available under traditional connection solutions implemented by network operators to date as any risk is designed out at the design stage. Implementation of future ANM systems will require a higher level of co-ordination and have a linkage with existing and/or future SO/DSO balancing systems to have the ability to send and receive information in respect of dynamic export limits. From a technical perspective future ANM deployment schemes shall require to accept dynamic set points that provide or limit access to the transmission system in real-time. How a DNO/DSO and those market participants providing the response is compensated requires further consideration at an industry level however, supports the view that a future DSO model must facilitate a more open and balanced energy market for all participants. This will only be achieved through the extended use of ANM systems; and through greater supervision and control network technology that can interact directly with a variety of Distributed Energy Resources.

Operational and practical changes

In recognition of the potential conflict between the proposed ANM system at Dunbar GSP and potential for distortion of the existing balancing mechanism by instructions to curtail generation passed between the SO and the existing BEGA/BELLA connected distribution generator not being realised, we established the requirement to retrofit ANM to the existing generator so that it could become part of and benefit from the wider ANM scheme being implemented under Dunbar GSP. The implementation of the project and ANM was never intended to have the consequence of adversely impacting or distorting the wider balancing mechanism.

4.3. Expanding the Learning: Enduring ANM at Berwick GSP

Using the learning from Dunbar, a similar contract was offered to generators wishing to connect in the Berwick GSP area. A connection offer that would be governed by the existing BEGA/BELLA arrangements was initially offered to two large wind farms wishing to connect at the 33kV busbar. Following initial engagement with the developers to present the ARC project, they quickly established their interest in exploring an ANM connection that could manage their output against any potential constraint at the T-D boundary. The requirement for a transmission Load Management Scheme would however have to remain as the ultimate protection of the transmission network.

Unlike Dunbar, the volume of generation wishing to connect has not reached a level such that the investment case for reinforcement for normal system running at the GSP is justified. Developers have therefore been offered an enduring ANM contract to connect to the network under Berwick GSP.

A third, smaller 1.5 MW development is also connecting to the network under an ANM connection. The next developer who applies to the network will likely trigger the reinforcement of the GSP and it will be at that point that we will offer them a two-stage connection offer similar to that for Dunbar. Those future customers would also benefit from the installation of ANM to accelerate access to the network as part of Stage 1 with Stage 2 the realisation of a 'firm' connection following payment towards and completion of transmission reinforcement works.

5. Trial of New Statement of Works Process

5.1. Statement of Works Process

Issues with the existing commercial contracts have been outlined in the previous sections. They highlight that the design rules and commercial solutions that exist today need to evolve to consider a world in which large scale embedded generation at distribution voltage and more and more GSPs export onto the transmission system on a regular basis. There is a real need to re-define the rules and increase the information exchange between the SO, TO and DNOs. This is increasingly important as ANM and other types of flexible connection solutions are rolled-out.

We identified solutions that have overcome the access difficulties at Dunbar and Berwick GSP without negatively impacting the transmission network or system operation. If the connections at Dunbar had been facilitated through the conventional approach then all new generators would have required separate commercial arrangements to access the network and hosting capacity would have been limited. The ARC project demonstrated the benefits of using ANM to trigger or defer network reinforcement, and the ability to manage embedded generation against wider network constraints. This learning is already being applied to other areas of the SP Energy Networks licence areas.

In parallel to activity as part of the ARC project, our Commercial Team worked with industry through the Energy Networks Association (ENA) Open Networks Project to implement a trial of a new SoW process at three GSPs within the SP Distribution electricity franchise area.

The purpose of this trial is to further accelerate the time it takes to notify generators of any impact that their proposed project may have on the transmission network and the costs and liabilities that they will be subject to in order to realise a connection to the network. As part of this process, National Grid has agreed a TEC level trial per GSP with the incumbent DNO. It will then be the responsibility of the DNO to plan its network appropriately in order to facilitate new generation connections – whether that is through conventional, firm connections or flexible ANM connections. The DNO becomes responsible for managing all generation against the GSP TEC.

This trial seeks to improve the information exchange between the DNO/SO of every individual connection at distribution level as and when they arise but remove the requirement for the DNO to make an individual SoW application to the SO on every occasion that a single generator makes a generation connection application to the DNO.

This new process is being trialled within the ARC trial area and provides any new DG customers seeking connection to the distribution system with enhanced early visibility of any wider transmission constraints. The DNO then implements all control of the generation via a single interface with the SO, resulting in no additional contractual arrangement for the DG customers with the SO. For example, during an outage, the national system operator may call up a turn-down service via the DNO, rather than the individual generator themselves. For customers the benefits of having a single point of contact for all system instructions avoids any cross over or confusion between transmission and distribution operators.

An outline of the proposed streamlined SoW process is shown in Figure 12

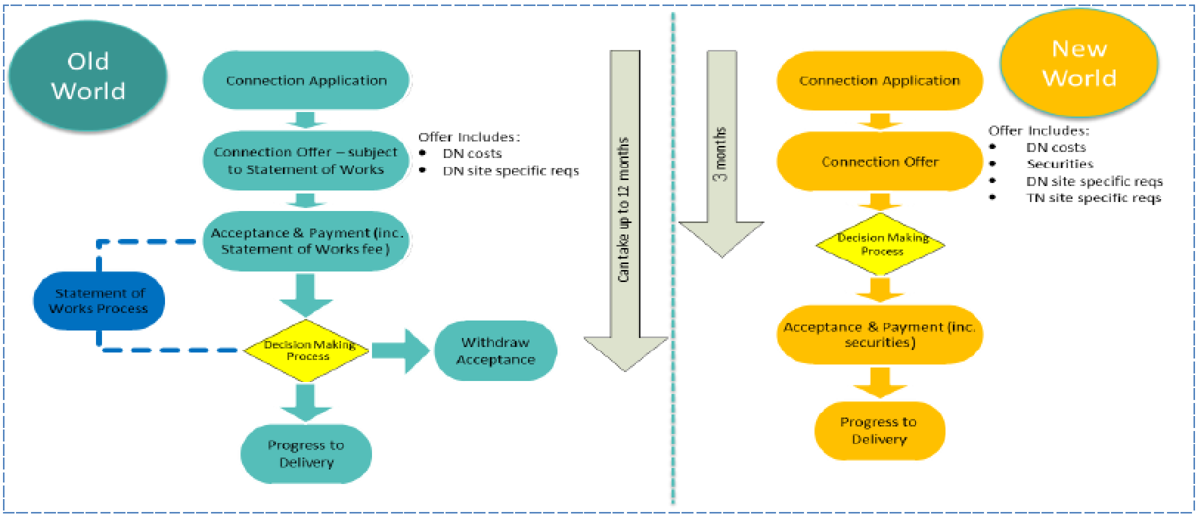


Figure 12: Proposed Streamlined SOW process.

5.2. ANM Net Effects on System Balancing

Enhanced collaboration and the sharing of information and operational experience between SPEN and the SO during the ARC project have advanced innovative thinking in the area of T/D interaction with ANM. More specifically in understanding how ANM and non-BM unit embedded generation will respond when the SO takes system balancing actions on BM units and demand under actively managed GSP groups. Understanding ANM behaviour was critical in the development of the risks associated with different types of ANM architecture to the effectiveness of SO actions. What is required now is collaborative development of a method to ensure ANM does not cause a net reduction in the effectiveness of SO actions. Indeed, ANM offers a much greater opportunity for more support from assets connected to the distribution network to contribute to system balancing if the appropriate commercial arrangements can be put in place.

5.2.1.1. ANM Management of Constrained Transmission Assets

The learning from ARC has advanced understanding of the complexities in implementing ANM fully at transmission level and managing constraints on transmission assets beyond the GSP. There are a number of ways this could be achieved, such as a variable TEC being set by the SO and communicated to the ANM, or alternatively communication of measurement data at constraint locations on the transmission network. Careful consideration will be required when a combination of BM unit, non-BM unit, distribution connected, and transmission connected generation are contributing to the constraint being managed. While the technical complexity can be readily overcome, the commercial complexity of such a situation is yet to be fully understood. ARC has demonstrated learning on the T-D interface issue and kick-started the debate which is now being addressed through various working groups, including those managed by the ENA.

6. The impact of ARC on the wider industry

During the course of the ARC project, there has been a general shift in industry thinking. When the project started in 2013, ANM was a relatively new methodology in connecting embedded generation, with deployments typically trialled under various innovation funding mechanisms such as RPF, IFI and LCNF. However, since 2013, ANM has been deployed as business as usual in a number of DNO licence areas, and the volume of embedded generation connected to the system has grown. An image from the most recent National Grid system study (see Figure 13) highlights the estimated 7.8GW of generation connected at lower voltage levels, which currently the SO has no visibility of.

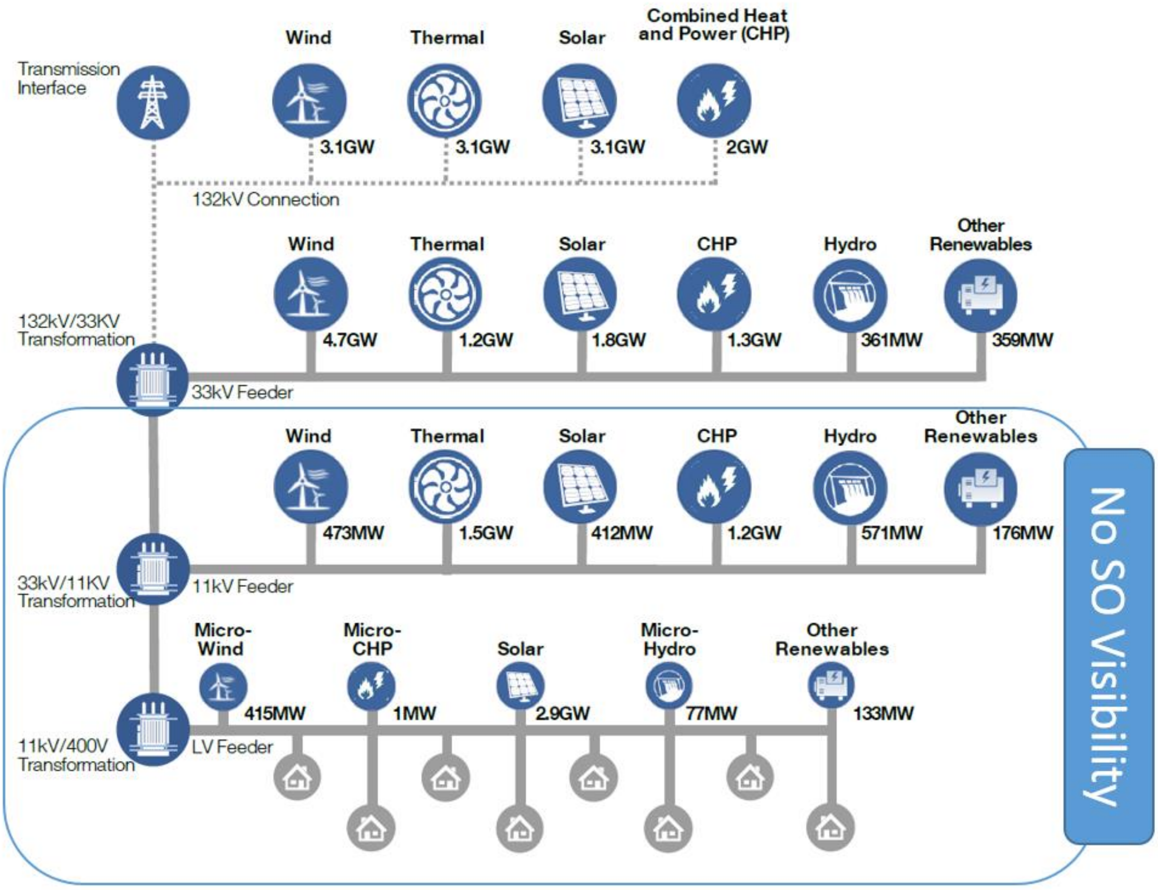


Figure 13: Extract from National Grids System Operability Framework demonstrating volume of generation connections across UK voltage levels. [4]

[4] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/#

The publication of a number of documents, code reviews, and consultations in 2015 reflects this shift in how the system may need to be operated in future.

6.1. Emerging Requirements

6.1.1. Reactive Power Compensation

The SO, through the System Operability Framework, has documented the changing nature of the reactive power profile. There is a significant decrease in the consumption of reactive power leading to difficulties in managing voltages on the transmission system. The proliferation of DG can compound these issues if their reactive power contribution is not carefully managed. In most cases, DG has been implemented with a fixed power factor and it is not actively changed.

Beyond the passive approach to DG reactive power management, there is an opportunity to extend ANM into the sphere of reactive power control. Most modern DG assets have extensive reactive power capability and can dynamically adjust reactive power in the same way they currently do for real power. The use of ANM presents an emerging, and technically viable, alternative to reactive compensation connected at transmission.

6.1.2. Energy Storage

There has been a dramatic rise in the number of applications for the connection of energy storage to distribution networks across the UK. This is most likely a product of the reduced cost of energy storage technology, reducing generation capacity margins, and access to new revenue streams. Enhanced Frequency Response[5], a new service being procured by the SO, is one such example.

These battery energy storage systems typically all connect via distribution networks. To be cost effective they require economically viable grid connections. From an SO perspective they need to know that the device will be able to import or export, and provide the ancillary service to balance the system when called upon. As a potential generator when in export mode these devices are most likely to have to connect to the network via a managed connection. The system interaction issues highlighted by the ARC project quickly extend to energy storage and demand that the DNO becomes more closely aligned to the needs of the overall system; but they need the remit to do that. The ARC project and subsequent review to the SoW process are the first enablers to more coordinated control by the DNO on behalf of the SO, and we expect to see that extend to energy storage very soon.

The emergence of distribution grid connected energy storage, and its potential importance for the secure operation of the GB System, is a striking example of where a whole system approach to future system planning and operation is required.

[5] http://www2.nationalgrid.com/Enhanced-Frequency-Response.aspx

6.2. Recent Relevant Publications

6.2.1. ANM Good Practice Guide

In July 2015, The ANM Good Practice Guide was published by the ENA. This document is intended as a guide for all stakeholders in the electricity market, including:

- ✓ Network operators who might install ANM on their networks;
- ✓ Developers who may be offered an ANM connection;
- ✓ Suppliers who may manufacture ANM or other supporting ANM technology; and
- ✓ Regulators and policy makers.

The guide provides a common understanding of what ANM is, and brings together case studies and reference material to help guide the future of ANM developments. The guide includes information regarding ANM connection design and connection process, system architecture, functional specifications, control room interface and responsibilities, failsafe modes, people and processes and network interactions.

The ARC project is not listed as one of the case studies, but many of the projects which ARC has taken learning from are (e.g. UKPN Flexible Plug and Play, SSEPD Orkney).

6.2.2. National Grid ANM Guidance Note

In July 2015, National Grid published a guidance note on ANM[6]. The purpose of this document is to provide some examples of scenarios were ANM may, or may not, impact on the operation of the transmission system. The way in which the SO should treat ANM controlled BMUs is undefined therefore action is still required to address these issues. The seven scenarios in the guidance note present a range of situations, and they all demonstrate the importance of visibility and information sharing between zones of control.

The ARC Case study at Dunbar GSP has informed this discussion and provides a blueprint for how similar systems can be implemented in a consistent and sustainable approach.

The guidance note lists a number of considerations which should be taken in any case where ANM is adopted. These include:

- ✓ The impact on the effectiveness of demand management;
- ✓ The need of the SO for balancing services provided by marking participants under ANM control;
- ✓ The need for control signals to flow between SO Energy Balancing System (EBS) and ANM;
- ✓ The cost of additional functionality of the EBS that must interface with the ANM scheme;
- ✓ ANM should not obscure the need for network investment in the future;

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[6] 09 November 2015, "Guidance Note - Active Network Management v1 0", http://www2.nationalgrid.com/uk/services/electricity-connections/policies-and-guidance/

- ✓ ANM should have the ability to react within sufficient time frames to post fault conditions; and
- ✓ ANM will not preclude the need for a formal connection application process.

6.2.3. System Operability Framework 2015

The creation of the ANM Good Practice guide highlights the growth of ANM throughout the wider industry, thus creating a requirement for a single reference source for all stakeholders. The increase in volume of embedded generation has also impacted the wider system operation. National Grid published its first System Operability Framework (SOF)[7] in 2014. The purpose of this document was to provide an overview of the future issues National Grid might encounter due to a change in the way our energy system is used and is in line with other studies, such as National Grid Future Energy Scenarios. These changes range from new technologies coming to the system, to changes in the generation mix and demand side response.

The first SOF in 2014 was welcomed by stakeholders and following some stakeholder engagement, and several rounds of feedback on the 2014 SOF, the 2015 version included more distribution system related information. The three strategic themes of SOF 2015 included:

- ✓ Services and capabilities;
- ✓ Whole system solutions; and
- ✓ Increased flexibility.

ANM has been discussed at length in the 2015 SOF. This document has developed the ideas of a coordinated/enhanced system operation further and supports that ANM is required to provide a safe, secure and reliable 'whole system' solution for the future energy system.

Of particular note is that there is an entire section devoted to the issues surrounding the growth of embedded generation. Key issues which arise with the growth of embedded generation include:

- ✓ Changes in the daily load shape, in particular, due to high levels of embedded PV;
- ✓ Increased risk of disconnecting net generation if Low Frequency Demand Disconnection (LFDD) relays operate;
- ✓ Voltage instability due to large power flow exchanges between networks and a lack of sufficient dynamic voltage control capability; and
- ✓ Increased use of ANM leading to greater complexity and the need for closer interaction between distribution and transmission.

The SOF highlights that without sufficient coordination between SO, transmission and distribution companies, ANM can increase the uncertainty of short-term demand forecasting and interactions between SO and ANM actions. It states that, with the correct enablers, "**ANM is a first step towards the evolution of Distribution System Operators (DSO)"** and provided that concerns are addressed

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[7] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

with regards to the sharing of information between stakeholders, then ANM should not be detrimental to system operability.

ARC has demonstrated the ability of ANM to enable connections for DG, and highlighted the importance of coordination between transmission and distribution networks to ensure the best approach to whole system operation.

6.3. Emerging and Proposed Governance Changes

6.3.1. STCP

In November 2015 a new STCP (System Operator-Transmission Owner Code procedure) [8] was proposed to cover the functional requirements of ANM schemes at transmission level. While the majority of effort has been to explore the deployment of ANM at distribution level there was very little in terms of formal documentation for how National Grid, as SO, should treat ANM. The STCP defines the interactions required between the SO and the TOs (SPT, SHETL and NGET) for the purpose of introduction and management of ANM schemes. The procedure ensures that the design requirements of ANM schemes and ensure that the ANM schemes will appropriately release the responsibility of the SO satisfactorily.

This document is one of the most significant documents and proposed modifications to be published during the period of the project. It represents the realisation by the SO that changes at lower voltage levels now have significant implications for the wider system. At the start of the project, ANM was an issue for distribution networks alone; however we have demonstrated that wider system issues can also be managed effectively by the DNO using ANM.

The diagram in Figure: 14 demonstrates the Dunbar trial area scenario. Monitoring does not cover any actions which come through from transmission level as discussed throughout this report.

[8] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/STC/Modifications/PM080/

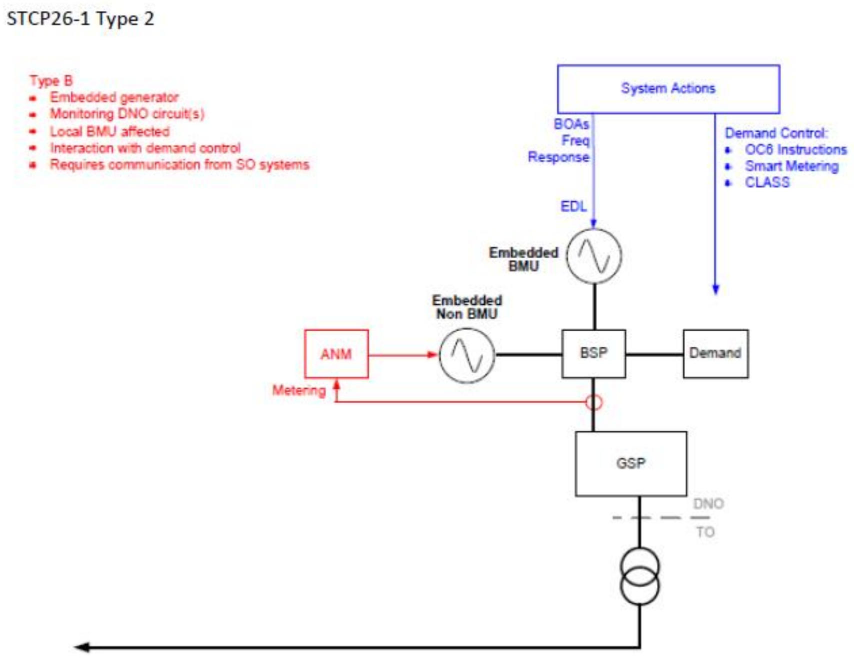

Figure: 14 STCP26-1 Type 2 from the ANM Guidance Document

6.3.2. Revising the SOW process

The SoW process in place when the ARC project began was viewed as being too complex, opaque, and time intensive. At the time, non-firm access was only available via a BELLA/RAA connection agreement. In 2015, the ENA began a process of stakeholder engagement and set up a working group to look at ways to address these concerns due to constraints experienced in the South of England. The culmination of these efforts was a strawman revision to the SoW process, which was presented to the wider stakeholder community in 2015. At the end of 2015 and into 2016, a more detailed revision to the process was developed with trials and full implementation expected by the end of 2016.

A major output to the process is the introduction of planning limits, e.g. DG headroom at the GSP, being made available by the SO in advance of DNO requests, with a schedule maintained for each GSP with contracted and connected DG. This is underpinned by more regular information exchange to ensure DG schedules and planning limits are up to date. Under this process the DNOs can make connection offers without submitting individual SoW requests for each DG. However, in some cases this will be unavoidable and conditional offers will be required with modifications advised by the SO if the conditional offer is accepted.

It is expected that the revisions will reduce timescales and costs as well as being viewed as simple, transparent, and consistent. SPEN has been at the forefront of this effort under the ARC project and has begun trials in the SPD license area a described in Section 5.1.

6.4. Industry Working Groups

Since 2012, a number of new working groups have appeared in the industry. This section will present several of these new working groups which are of relevance to the ARC project, and discuss how challenges discussed in these working groups have been demonstrated and overcome throughout the ARC project.

6.4.1. ENA ANM Working Group

This group was established by ENA in late 2013 with the aim of developing a consistent understanding of ANM and its application to electricity networks across the UK. Members of the ARC Project team sit on the ANM Working Group. Other members include representatives from all other UK DNO's and National Grid.

It was this group that commissioned the ANM Good Practice Guide (See Section 6.2.1) and more recently, published a consultation in to standardisation of Curtailment Assessments – a key element of the ANM connection process for both DNO's and developers[9].

6.4.2. CIRED Working Group 2015-1 – TSO-DSO Role and Interface: evolving roles and technical solutions

The purpose of the workshop is to interact with CIRED stakeholders and explore the need for coordinated control between distribution and transmission operators. It deals with the technical issues such as data exchange and the impact of underlying ICT architectures.

There are a number of use cases which will be used to explore these issues, and they range from issues surrounding the flow of real and reactive power at network boundaries, security and protection, and network planning issues such as long term planning and balancing issues.

The issues addressed by this working group cover a number of the challenges encountered during the ARC project. In particular, the control of real power at the boundary between distribution and transmission level in the case of the Dunbar GSP, and transmission balancing actions being undermined by ANM actions at distribution level. ARC has highlighted the importance of sharing of information between transmission and distribution systems and will provide a valuable international case study for the CIRED Working Group.

Members of SP Energy Networks and two project partners – Smarter Grid Solutions and University of Strathclyde - are participating in this working group.

[9] http://www.energynetworks.org/assets/files/news/consultation-responses/Consultation%20responses%202016/ANM%20Curtailment%20Consultation%20February%202016%20Final.pdf

6.4.3. CIGRE Joint Working Group: C2/C6.36 System Operation Emphasising DSO/TSO Interaction and Co-Ordination

This Joint Working Group is run between the System Operation and Control study committee (C2) and the Distribution Systems and Dispersed Generation study committee (C6). The aim of this working group is to define a catalogue of procedures that allow the DSO and TSO to interact which will maximise the benefits of DG and demand-side response. The working group will also explore how to optimise and deliver ancillary services from the distribution connected energy resources (e.g. generation, demand and energy storage).

The scope of the working group includes exploration of frequency control and voltage disturbances and the transmission - distribution boundary, reactive and real power management, operational planning and management of both systems and the topic of data-exchange between DSO and TSO.

This working group takes learning from the ARC project to the next phase by exploring potential market services at distribution level.

6.4.4. EURELECTRIC DSO

The Union of the Electricity Industry (EURELECTRIC) is the sector association which represents the common interests of the electricity industry at a pan-European level, plus its affiliates and associates on several other continents. In February 2016 EURELECTRIC published a paper, "EURELECTRIC's vision about the role of Distribution System Operators (DSOs)."

The summary conclusions of this report support the results found through the ARC project, and include:

- ✓ DSOs are key players for enabling a successful energy transition while providing a high-quality service to all customers.
- ✓ DSOs are adapting to an evolving energy market by implementing changes in the way they operate and plan their networks.
- ✓ Energy regulators should recognise the broadening role of DSOs as neutral market facilitators and encourage efficient technological innovation.
- ✓ DSOs should adequately support their customers.
- ✓ Data management must be fair, efficient, transparent, and non-discriminatory.

6.5. Industry work on future power system models

The information provided in Section 6 highlights the large number of areas that the ARC project has touched upon, from industry bodies, working groups, industry consultations, and projects. Similar groups are also discussing the move towards a DSO business model.

The GB System Operator publishes its 'System Operability Framework' and 'Electricity Ten Year Statement' each year. Between these two documents, they set out the challenges and possible solutions from a SO perspective. The SOF touches briefly on the issues caused by the increase in embedded generation and the need for a 'whole system' approach to solving these issues, however it does not reference particular network areas (different network areas have different mixes of DER and network topology and therefore have different issues). The SOF also mentions that ANM is the first technology step required to progress towards this whole system solution and eventually, a DSO model.

The DECC Future Power System Architecture (FPSA) project is concerned with whole system thinking with a focus on new technical functionality of the GB system in 2030. The FPSA report discusses a subset of new functions likely to be either implemented or operated by a DSO or require significant new coordination/interaction between the SO and DSO.

The Smart Grid Forum (WS6 and WS7) are now approaching completion with strong relevance to DSO and new business models for DER. Since 2011, these WSs have created documentation on the commercial and technical views of the distribution system in the future and the results of the Smart Grid Forum will now effectively be rolled into and be taken forward by the Ofgem Flexibility Project.

The Ofgem Flexibility Project acknowledges the role DG, energy storage and DSR will play in delivering the required flexibility in GB future system. The position paper[10] sets out the role that DER, new entrants, active participation in the operation of the GB system, and new business models might play in future and the benefits of this. The Flexibility Project has a planned work programme through 2016 and the outcomes of the ARC project can play a valuable role in the direction of the Flexibility Project.

7. The next steps

7.1. Immediate next steps

The immediate next step is to realise the value of implementing flexible connection solutions, complemented by innovative commercial offerings such as two-stage connection agreements to navigate similar challenges across the network. Where good practice has already been established it will be implemented immediately, and broadly, across our license areas through policy amendments and where necessary, the creation of new policy.

There are two areas where work is still required to establish recognised and consistent good practice, but through the successes of the ARC project, it can begin from a well-informed position. These areas are the **exchange of information** and **co-ordination of control** across the real-time, near real-time and future planning time domains between the DNO and SO. The following section explores these topics in more detail.

7.2. Developing Information Exchange and Control Coordination

If ANM is to succeed as a viable long term option for the connection of future generators and DER, it is crucial that there be a much more fluid exchange of information between the DNO and the SO.

[10] 'Making the electricity system more flexible and delivering the benefits for consumers', Ofgem, Sep 2015.

DNO's and the National System Operator's new energy balancing system (EBS) has not yet been integrated – as historically there was no requirement for it to be. Network management systems are not set up to coordinate or share real-time information. The current process for sharing of information is via statutory long term planning documents such as Week 24 data, Ten Year Statements, the SoW Process and the Long Term Delivery Statements.

Both entities have a license obligation to operate an efficient system i.e. minimise the costs for the end user. The current inflection point of the network has led to increased interaction between systems which will likely increase the need for greater information sharing and clear parameters of control across the T-D boundary. To date, and as demonstrated in figure 16, the flow of information between the system operator and embedded assets which participate in the balancing market, as well provide support services for STOR or EFR, currently do not communicate with the DNO's DMS or ANM system. Meaning that information transfer between the SO and end user of the system bypasses the DNO who may require visibility so as not to distort the market with conflicting actions.

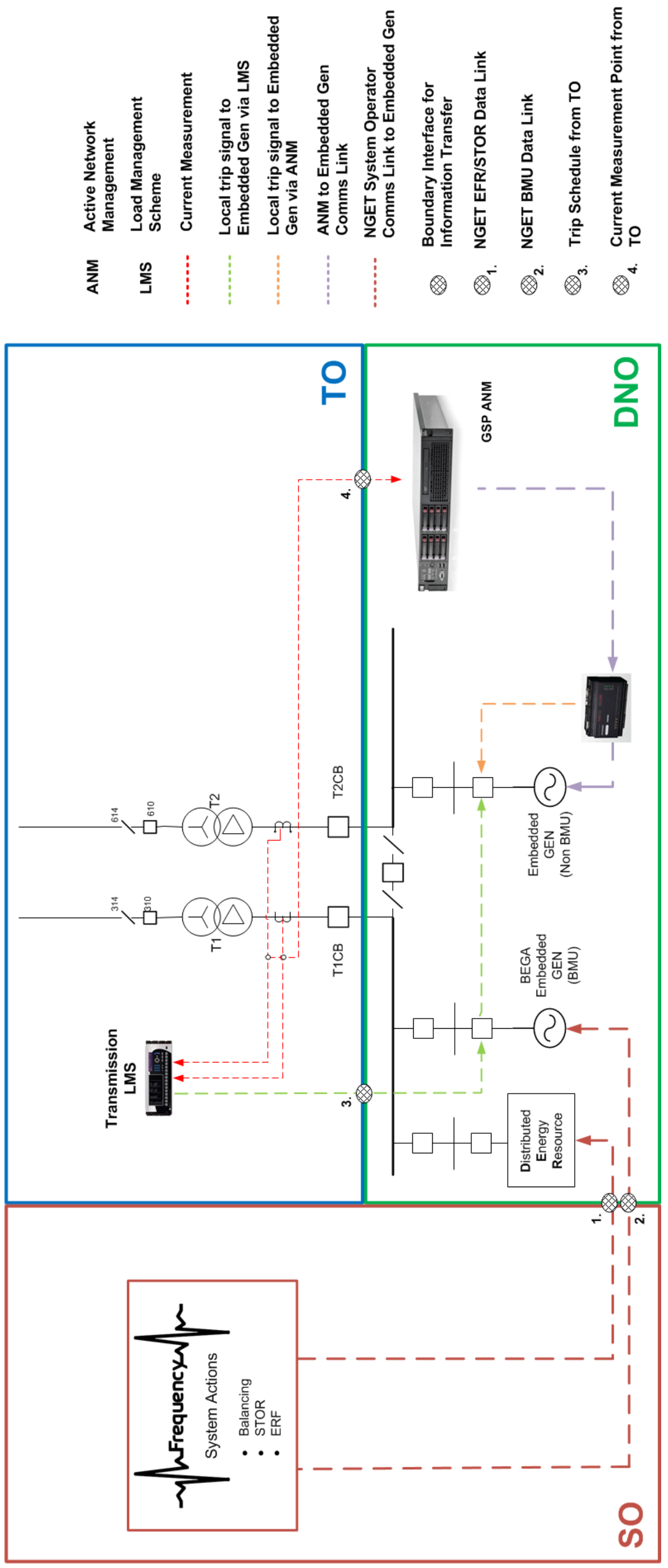

Figure 15: Current Information Architecture at Dunbar GSP

Uncertainty caused by lack of visibility has created a system operator conservative in its approach to network management on both sides of the transmission and distribution boundary; for example, overload protection schemes being offered over a more sophisticated managed connection approach. Breaking down the information barriers will allow more intelligent and real-time control of the network that is far more efficient than current 'on-off' principles of network management.

This relates to both future planning of the network, and the real-time day to day operation of the system. The sections below set out the steps we believe are needed to ensure successful and sufficient information exchange and control coordination.

7.2.1. Planning

In the first instance, the SO and DNO's have to exchange information on the level of DG connected, committed, contracted to connect, and in the connection application queue. This provides the SO with the basis for short and long term planning and the provision of DG headroom for each GSP before works are triggered at transmission level. This exchange of information supports the continuation of the innovative commercial arrangements trialled as part of the ARC project; for example, the proportional allocation of SoW costs across a grouping of ANM connected DG.

In addition to information on the connected, contracted, and offered background DG at each GSP for planning purposes, there is a need for more operational data required to form operational profiles. These profiles can be used as inputs for more informative time-series modelling of import and export behaviour at the GSP and how this is impacted by DG. Forming a better understanding of DG export over time and being able to unmask changes in demand, something which is further expected with the uptake in LCT, will aid the SO significantly. A more complete package of ANM data, including ANM measurement point data, permits the SO to analyse the behaviour of DG specifically related to ANM and also the behaviour of DG following actions taken by the SO.

Supplementing these efforts will be the provision of a model or the information required by the SO to build its own model of ANM operation at each GSP. The SO and DNO should, in the near term, start to discuss the format for these models and how they will be updated over time as ANM schemes grow or their configuration changes. This is a critical component of the ANM STCP and SOF for both the design approval phase and ongoing operational planning of ANM.

It should also be noting that a growing proliferation of embedded flexibility contracts being exchanged between the National System Operation, and embedded flexibility assets connected to the distribution network could significantly distort the DNO's ability to provide flexible connection solutions in future. To resolve this problem, new mechanisms of information exchange must be created between DNO's and the SO with regards to flexibility contracts, such as STOR and EFR so as to allow DNO network planners to better understand network behaviour when assessing long term network availability for future ANM connections, but also for determining when necessary network reinforcements might be triggered or deferred.

7.2.2. Real-time Operation

There are two aspects to the real-time operation of ANM where information exchange can be developed in the near term. Firstly there is the continuous monitoring of the live ANM system, with streaming of status updates, measurement data and dash-boarding of key metrics per GSP. Secondly, there is the scope for the DNO to provide information that will allow the SO to perform what-if scenario (or, more formally, contingency) analysis. An example of this could be the effects of a BM unit turn-down event. This will be dependent on the accuracy of the ANM model and therefore the SO will need an updated model with the live system configuration. This adds an additional burden, not only in the maintenance of an up-to-date model, but also the verification of the model held by the SO. What-if scenario analysis could become critical to the success of ANM roll-out as it provides the SO with the tools to understand when the actions it plans to take will achieve the desired effect and when they will not, and where supplementary action is required.

As described in National Grid's SOF document, there are a number of ANM architectures that will only be truly viable if the SO can action ANM controlled assets at the same time as taking action on embedded BM units. This is to prevent ANM DG utilising capacity created by SO actions that have an associated cost. A means of co-ordinating SO and DNO ANM control actions, most likely in a hierarchical form, creates a far more complex ANM architecture to that previously deployed and demonstrated under ARC.

The SO and the DNO will need to agree both commercially and technically how the capacity created by SO actions can be calculated, verified through measurement or other methods, and then discounted by the ANM system when allocating capacity to non-BM units. This could eventually involve direct intervention by the SO in the operation of ANM to dynamically alter thresholds used to determine capacity allocation, for example as variable TEC.

7.3. Consolidate Agreed Commercial Agreements around Desired T-D Interface Coordination Mechanisms

We engaged in extensive discussions with the system operator around the Dunbar GSP case study and from this came a significantly improved understanding of the issues and concerns surrounding the coordinating of control actions across the transmission and distribution boundary. Gaining support and agreement has been the key to the success of the project and has already triggered other industry initiatives. Though a variety of commercial and technical workshops at the beginning of the project, the SO and TO gained confidence that the technology could deliver a suitable solution for all parties, and was successfully demonstrated during a prolonged N-1 outage in 2016, and provided evidence based learning to both the SO & TO regarding the treatment of future project areas that may deal with the similar problems.

The next step should be the development of a two-stage connection offer that would enable generators to connect to the network ahead of the completion of the transmission works. The two stage offer however also provides an option for enduring ANM connection, should the wider reinforcements not be justified. A template of the two-stage contract is shown in Appendix A. It is hoped that this template can be shared with other stakeholders for discussion, development, and eventually use across a wider set of development projects.

7.4. Aligned Incentives

There are differences in the way transmission and distribution network licensees are obligated and incentivised to run their networks, but as the industry moves towards 'whole system' solutions, then it could be argued that the transmission and distribution businesses should have aligned incentives.

For example, if there is more generation connected at distribution level, this can increase the number of times a constraint occurs at transmission. This will increase the cost of curtailment for the SO who are currently incentivised to reduce these costs, and who benefit commercially from outperformance. This cost could be reduced by curtailing embedded generation via emergency instruction, thus negatively impacting on the distribution network operation. If transmission and distribution had similar incentives, this conflict of interest could be avoided and provide fairer treatment of generation on the network.

Aligning incentives would ensure that there are no conflicting objectives to the operation of the network and align the SO and DNO towards a single goal. This ensures the license obligation to provide efficient operation of the network and lower costs for bill payers.

The key to flexibility is managing the existing network and ensuring that it is utilised in the most efficient manner, with a key performance indicator being the assets utilisation capacity factor.

8. ARC pathways towards DSO

Several of the specific T-D boundary issues tackled in the ARC project have led, informed, or reflected recent developments in the UK energy sector. The UK energy industry, along with international initiatives such as CIRED and CIGRE working groups and EURELECTRIC activities on the question of the future DSO, has identified and begun the process of tackling the challenges at the T-D interface.

In January 2017, the creation of the ENA OPEN NETWORKS project has brought together all 9 UK network operators to develop a coordinated roadmap towards transitioning the way in which the electricity networks operate in future. Work Stream 1 of this project represents a coordinated development towards improved T-D interface processes around connections, planning TSO/DSO services and operation, with a use case being the trial of Active Network Management at Dunbar GSP via the ARC Project.

Much of this exploration is happening within the context of future DSO business models. There are several strands to DSO including Distributed Energy Resources (DER) customer service/enabling, enhanced distribution planning, more efficient distribution network operation, and local markets for energy and services. The interface and interaction of transmission and distribution networks is one of the key strands of the DSO models under exploration and this section maps out the contributions of the ARC project into wider industry discussion, listed below;

1. DNO/DSO's should be able to maximise the efficiency and utilisation of the distribution network through implementation of flexible connection solutions which may result in a higher levels of connected capacity than the current permitted under existing design codes.
2. Transmission Constraints with DER solutions at distribution - ARC adds learning on control solutions and architecture to the technical control methods for the TSO/DSO future. See figure 17;
3. Information Exchanges between transmission and distribution are a key requirement to enabling a whole system solution.
4. Planning Approaches by utilising actively managed connections to support wider network upgrades and planning.
5. Connection Application Process by considering alternative routes to connection can provide a way to maximise available network utilisation, which leads to a more actively managed distribution network.
6. Commercial Arrangements with new terms (including the potential for variable TEC at the GSP and two-stage contracts) are essential to support the technical design of a flexible system.

The solutions developed and trialled through the ARC project provide a foundation to develop enduring interface arrangements between the transmission and distribution networks and allow the Evolution towards DSO business models.

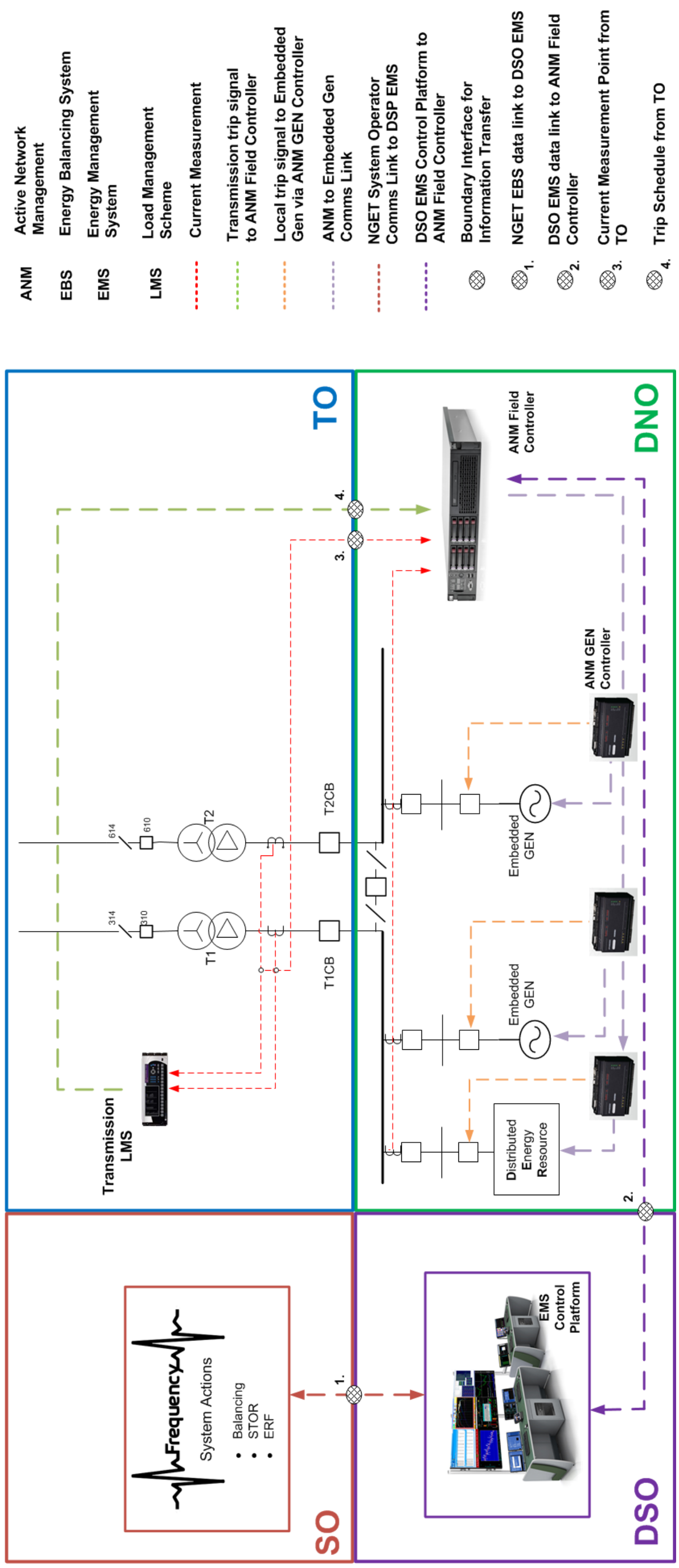

Figure 16: Potential DSO/ANM Future Architecture

Growth in embedded generation, combined with few effective SO-TO-DNO mechanisms to deal with the emerging system operation challenges leads to an obvious requirement for active Distribution System Operation. Change at this scale takes time, for example, DNOs in Scotland have been dealing with constraints at Transmission level for many years. Only now that these issues are manifesting themselves in the south of England, is the industry engaged in a review of the SoW process.

8.1. Benefits of a DSO model

A DSO model is an essential part of managing a whole system solution, and enabling transmission and distribution licensees to operate effectively across the physical transmission to distribution boundary.

The first stage of the DSO model is to provide a TEC capacity to each GSP and allow (for the time being at least) the DNO to operate as DSO and manage generation within the GSP. This transforms the GSP into a 'controllable or dispatchable unit that can be considered by the SO for system operation as a large transmission asset, and participate in all transmission related activities.

The DSO model will allow more effective management of multiple DERs in more complex network 'configurations' while contributing to an overall more efficient system through closer planning, operational planning, and operations coordination with TO and SO. As well as efficient and cost effective network and system operation, it will enable customer greater choice and allow DER developers mechanisms to access revenue streams that they are currently prohibited from.

Such efficient network operation can only be provided through enhanced coordination of services between the DNO and the SO. By enabling a DSO to increase the number of flexible assets offering balancing services either directly to SO, or via the DSO as aggregator, will open up the market and has the potential to drive down the cost of balancing. There may also be a reduced requirement for constraint management and other, similar balancing services due to the increase in information exchanged across the boundary. Providing the SO with a more accurate view of what is happening at distribution level, and allowing better system planning, may in itself lead to reduced system operation costs.

The DSO model will also allow DER mechanisms to access revenue streams that they are currently prohibited from. This is important in an industry where there is a current drive to reduce reliance of renewable technologies on subsidies. By opening up the market and allowing DER to generate revenue from services such as frequency response, voltage support, and constraint management can provide further support to the business case for development of DER and removes sole reliance on the export sale of electricity. With clearer, defined connection and operational mechanisms for DER customers, and specific energy and network/system service markets, there will be more options and additional market dynamics which should benefit customers, network licensees, and overall system economics.

8.2. Tackling network challenges with DSO

Once a DSO model is in place, this can then facilitate the progress of a number of other flexible and smart technologies on the market. As outlined above, enabling DER to generate revenue for a wider range of services can reduce reliance on electricity trading as the sole revenue for the development, but importantly, can create more optionality in the provision of network and system service. While this is an opportunity for more established technologies such as wind and solar, it can be argued that there are more benefits to be gained from this for new technologies on the market such as storage and DSR.

These technologies can be connected to the network as standalone systems, or integrated with other DER technologies such as wind, solar and hydro to maximise the available renewable resource e.g. storing excess wind generation when export is high to export during a low wind period.

Community groups, aggregators, and other service providers could operate within the distribution network and trade services to the balancing mechanism via the DSO if they chose not to interact directly with the SO. This role could create opportunities for DER developers to build out from a single DG unit to create a portfolio fit for flexibility service.

Finally, by creating a market for constraint management services at distribution level, this also creates a means for dealing with losses, security, maintenance, reactive power, and aggregated response/reserve provision. It is expected that as the UK begins to transition away from fossil based energy sources for heat and transport, an unprecedented pressure will be applied to the local distribution network to facilitate behind the meter changes in demand consumption, with EV's, heat pumps and domestic energy storage all starting to emerge as enduring technology. And for distribution network operators, flexibility and local balancing will be mandatory to avoid significant upgrades to the existing infrastructure which was at the time of installation, simply not designed to accommodate a Low Carbon economy.

9. Recommendations/Key Points

This report has discussed the key commercial implications of operating ANM across the transmission and distribution boundary.

9.1. Learning

New commercial arrangements and connections processes in this project have been demonstrated through the following:

- Application of a new two-stage contract for distributed connected generators. Facilitating a consortium approach to generators wishing to connect as part of an ANM scheme whilst wider transmission works are undertaken.
- Sharing of costs associated with wider network reinforcements, and granting connections under ANM allowing developers to generate revenue while wider reinforcement works take place.
- Retrofitting ANM to existing generation projects to facilitate increased flexibility during outage scenarios.
- Providing ANM as an enduring solution to facilitate connections of renewables in areas of the network where the business case for transmission reinforcement has not yet been triggered.

9.2. Key Findings

- The establishment of an industry T-D Steering Group, coordinated by the ENA, has been created to address similar issues now arising throughout the UK as more and more distributed generation and DER seeks to connect at distribution voltages. This report and its finding should be used as learning to help inform discussion and debate as part of that group.
- The commercial problems and solutions identified in this report are a key to providing the pathway to a DSO. The shift to DSO is the obvious and natural next step to deliver additional value to all customers. There are no current regulatory barriers to preventing the first steps towards a DSO, however there will be changes required in the coming decade to enable the DSO role to become fully embedded in the energy system.
- Any and all interactions with the balancing mechanism must be considered when installing ANM technology. There is a risk to over-riding balancing actions if the ANM system is not considered. Only solved by greater information and interaction across the T-D boundary.

9.3. Recommendations:

- There needs to be better definition of the boundaries between T and D, including clear and transparent rules regarding who is responsible for network operation and who has the 'right of way' when constraining generation and managing power flows on the network.
- To facilitate this, we'll need all the tools we talked about in Report 1, as well as some new thinking and commercial innovations. As with many elements of network innovation, the technology is already available, it is the commercial and regulatory framework that must be adapted to enable progression.
- There are certain changes to the regulatory framework required to allow a full DSO to operate in the GB energy market. We're a long way from this at the moment, but the move towards DSO has begun with lots of industry documents detailing 'whole system solutions' and 'flexibility'.
- Distribution System operation should become common practise within future distribution networks – as it is difficult to determine how flexible networks can operate without new roles, responsibilities, functionality, commercial arrangements, etc. nor without the required business models and regulatory mechanisms being introduced to support that.

10. Appendix A

Regulation & Commercial

Generic Generator,
ABC Avenue,

Town,

Local Authority,

Postcode

Date:

... /.... /......

Contact / Extension:

....

Tel: ....

Dear Sir,

CONNECTION OFFER IN RESPECT OF THE AGREEMENT TO CONNECT GENERIC GENERATOR PLANT (THE "DEVELOPMENT") TO THE SP DISTRIBUTION PLC DISTRIBUTION SYSTEM

The construction agreement (the "Agreement") to provide the electricity connection to the Development comprises: -

- **The Connection Offer Letter dated .../.../... made by SP Power Systems Limited (SPPS) (acting as an agent of SP Distribution Limited, now SP Distribution plc) to the Customer (the Offer),**
- **The acceptance from the Customer to SP Distribution Limited, now SP Distribution plc ("SP Distribution") dated .../.../... (the Acceptance) and**

This connection offer is provided to you in response to your request to be connected in advance of the Stage 2 NGET Transmission Works via an ANM Scheme.

SP Distribution reserves the right to modify the provisions of the Agreement to take account of any works, costs or restrictions imposed upon it by NGET.

NGET Offer Summary

The NGET Offer provides for the connection of Generic Generation Customer Ltd which includes the associated wider works necessary to facilitate the connection, subject to the derogation from the National Electricity Transmission Systems (NETS) SQSS being granted.

Stage 1

Registered Capacity	Estimated Completion Date
XYZ MW (Active Network Management Basis)	.../...../.....

Stage 2

Registered Capacity	NGET Completion Date
XYZ MW (Firm Basis)	.../...../.....

Accordingly, SP Distribution hereby exercises it right to revise the terms of the Agreement as follows:-

ACTIVE NETWORK MANAGEMENT SCHEME

DEFINITIONS

The following terms and conditions in this Appendix apply to the management of the Customer's export capacity under an ANM Scheme during that period subject to the derogation from the NETS SQSS being granted, and sets out in particular the basis of constraint of that part of the export capacity identified in the Agreement as being "Non-Firm"

"ANM Scheme"	Means the overall active network management scheme including but without limitation the **"SP Distribution Control Equipment"**.
"SP Distribution Control Equipment"	Means the equipment and technical specification set out in Paragraph 6
"Constrained Location"	Means those locations of constraint as detailed in Table 1 of this Appendix that affect the Connection detailed within this Agreement
"Constraint Measurement Point"	Means the equipment used to monitor Current and Voltage at an identified **"Constrained Location"**
"Curtailment"	(a) Means to limit from time to time the maximum amount of electricity that may flow into the Distribution System from the Connection Point The term **"Curtail"** shall be construed accordingly.
"Curtailment Instruction"	Means an **"Instruction"** given by the **"ANM Scheme"** to action a **"Curtailment"** of electrical power output by the **"Qualifying Generation Plant"**
"Dead Time"	Means a defined time where no action is taken.
"Forecast	Means any information, projections, data, estimates or forecasts as to

Constraint"	future levels of **"Curtailment"** provided by or on behalf of the Company to the Customer in relation to this Agreement
"Instruction"	Means an instruction given by SP Distribution to the Customer via the **"SP Distribution Control Equipment"** or verbally or in written form in accordance with the technical specifications set out in this Appendix in order to undertake **"Curtailment"**
"LCS"	Means the **"Qualifying Generation Plant"** local control system.
"LIFO Register"	Means of defining **"Qualifying Generation Plant"** position under a **"ANM scheme"** using a Last in First Off Methodology
"LIFO Stack"	Means of applying **"Qualifying Generation Plant"** with a **"Curtailment Instruction"** within an **"ANM scheme"** using a Last in First Off Methodology
"Local ANM Controller"	Means the hardware installed at any **"Qualifying Generation Plant"** metering substation, connected to **"LCS"**
"NETS SQSS"	National Electricity Transmission System Security and Quality of Supply Standard
"Non-Compliance"	Means failure to respond or comply with **"Curtailment Instruction"**
"Qualifying Generation Plant(s)"	Means any Generating plant connected to the **"ANM Scheme"**
"Subordinate Generation Plant(s)"	Means any Generating plant connected to the **"ANM Scheme"** that is behind the Customer in the **"LIFO Stack"**
"System Lockout"	Means the **"Local ANM Controller"** will restrict the energisation of the **"Qualifying Generation Plant"** based upon **"Non-Compliance"**.

1. TECHNICAL REQUIREMENTS FOR CONTROLLING THE INTERRUPTABILITY

1.1 The Customer's Generating Equipment shall be paralleled to the SP Distribution's Distribution System.

1.2 SP Distribution Control Equipment shall be installed at the Connection Points to:

1.2.1 interface the Customer's Installation and/or equipment therein with the SP Distribution's Supervisory Control Alarm and Data Acquisition (SCADA) Systems

1.2.2 conduct measurement of current and/or voltage in real time

1.2.3 convey an Instruction in digital format, to the Customer's control equipment to communicate the new Maximum Entry Capacity that may be utilised. The specification for such instructions is set out in Part 6 of this Appendix

1.2.4 provide volt free trip contacts, for operation upon failure of curtailment of Interruptible Entry Capacity, which shall be connected to the SP Distribution Connection Point isolator or circuit breaker in respect of curtailment Entry Capacity

1.2.5 provide volt free trip contracts, for operation upon failure of curtailment of Interruptible Entry Capacity, which shall be connected to the SP Distribution

Connection Point isolator or circuit breaker or if appropriate equipment under control of the Customer that may isolate the Customer's generating equipment

and the specific technical requirements will be set out in Part 6 of this Appendix.

2. CURTAILMENT

2.1 The Customer agrees that in the event that the power flows and/or voltage levels in any Constrained Location exceed the maximum available Entry Capacity as determined by SP Distribution, SP Distribution shall be entitled to give an Instruction in accordance with the technical requirements in Part 6 of this Appendix, to Curtail the flow of electricity through the Connection Point in an amount expressed in kW to bring the power flows and/or voltage levels at the relevant Constrained Location below the maximum available Entry Capacity provided that prior to issuing an Instruction to Curtail the Customer's flow of electricity through the Connection Point SP Distribution has ensured that all flows of electricity onto the Distribution Network from Subordinate Generation Plants have been reduced to zero.

2.2 SP Distribution shall ensure that all Subordinate Generation Plants shall have installed and be connected to the SP Distribution Company Control Equipment and shall be subject to the ANM Scheme.

2.3 SP Distribution shall be responsible for:

2.3.1 holding and maintaining a register of all Qualifying Generation Plants that connect to a Constrained Location (the "LIFO Register"). The Company shall hold a LIFO Register for each Constrained Location

2.3.2 ensuring that all Subordinate Generation Plants on the LIFO Register shall have at all times installed the SP Distribution Control Equipment and shall be subject to the ANM Scheme

2.4 SP Distribution shall ensure that all Subordinate Generation Plants that connects to the Constrained Location shall be added to the LIFO Register.

3. NO LIABILITY FOR FORECAST CONSTRAINT

3.1 The provision of any Forecast Constraint ("Forecast") related to and/or forms part of this Agreement that provides a view on the likely Curtailment that will be experienced by the Customer through the provision of the Active Network Management Scheme is consistent with current knowledge and practice. The provider of the Forecast and any party on behalf of whom the Forecast has been provided excludes all liability in tort (including negligence), contract and under any statute for any loss or damage arising out of or in connection with any reliance on the Forecast. Subject to the foregoing, to the fullest extent permitted by applicable law, all warranties or representations (express or implied) in respect of the Forecast as excluded.

3.2 The Customer's use of any Forecast provided by or on behalf of SP Distribution is entirely at the Customer's own risk. SP Distribution makes no warranty, representation or guarantee that the Forecast is error free or fit for the Customer's intended use.

4. ACTIVE NETWORK MANAGEMENT SCHEME

4.1 The Active Network Management scheme provides the ability for SP Distribution to manage multiple embedded generators and will issue a Curtailment Instruction to manage power flows within operational limits as calculated by SP Distribution or as instructed by NGET. The ANM Scheme will manage power flows across Constraint Locations through the curtailment of real power output (MW).

4.2 The ANM Scheme shall take the following escalating control actions to protect existing electrical network infrastructure relevant to the connection related to this Agreement.

Scenario	**Action**
System Intact both Dunbar Grid T1 & Grid T2 CB's are closed and system is deemed healthy	ANM Scheme will monitor and issue relevant Curtailment instructions to the Customer and curtail real power output of the generator when Dunbar Grid T1 & T2 132/33kV transformers reach 90% of their thermal rating. The ANM Scheme will recalculate generator set points and dispatch at a frequency of 600ms.
System N-1 loss of either Dunbar Grid T1 or Grid T2 transformers or loss of 132kV infeed during Low Generation/High Demand Periods	ANM Scheme will monitor and issue continuous trim instruction to Generic Generation Customer Plant and curtail real power output of generator when the remaining 132/33kV Dunbar Grid transformer reaches 90% of its thermal rating. The ANM Scheme will recalculate set points and dispatch at a frequency of 600ms.
System N-1 loss of either Dunbar Grid T1 or Grid T2 transformers or loss of 132kV infeed during High Generation/Low	ANM Scheme will issue trip instruction to Generic Generation Customer Plant if Trip threshold is breached, typically 100% of remaining transformers rating. After a predefined Dead Time the Local ANM Controller will attempt to re-energise the customer once the generators electrical output has dropped to zero. Customer will be released capacity in predefined steps until the remaining transformer reaches 90% of its thermal rating. ANM Scheme will

Demand Period	hold the reverse current flow across the remaining transformer to a limit of 90%. The ANM Scheme will recalculate set points and dispatch at a frequency of 600ms.
Communications failure between the Local ANM Controller installed at Generic Generation Customer Plant and the central Dunbar ANM system.	In the case of failure of communication between the central servers and the Local ANM Controller, the Local ANM Controller will fail to safe and limit the output of the generator to a pre-defined level (0MW).
Communications failure between the constraint measurement point and the central Dunbar ANM system.	In the case of failure of communication between the central servers and the constraint measurement point, the Local ANM Controller will fail to safe and limit the output of the generator to a pre-defined level (0MW).
Management of Generator for **non-compliance** i.e. failure to comply with ANM set-point.	After a defined period of time the ANM Scheme will attempt to unload the generator (reduce output to zero). If the generator fails to respond to the command to unload, after a defined period, the ANM Scheme will trip the network's metering circuit breaker.
Dead Time following generator trip signal being instructed	The ANM controller will wait for a pre-defined number of seconds before attempting to close the circuit breaker and bring the generator back into service. The Dead Time will exceed the time required for the generator to reduce its electrical output to zero on the other side of the breaker.
Trip lockout due to non-compliance	If the system trips the generator 3 times due to non-compliance 3 times within the auto reclose reclaim time, the ANM Scheme will lockout the circuit breaker and not attempt to re-connect the generator. Manual intervention is required to reconnect the generator to the system. The reclaim time shall be based upon the SP Distribution auto reclose policy.

5. CONSTRAINT LOCATIONS & LIFO STACK POSITION

5.1. ***Table 1*** of this Appendix provides information relating to the identified Constraint Locations relevant to this Agreement and the position in the LIFO stack of the generation equipment relevant to this Agreement at as the date of this Agreement.

Constrained Location	***Substation or Circuit References***	***Description of Constraint***	***LIFO Stack: Position Number (of Total)***
Dunbar 132/33kV GSP	132/33kV 60MVA T1 & T2	Thermal Transmission	**X** (Of **X**)

6. SITE TECHNICAL REQUIREMENTS

6.1 The Customer shall provide a Local Control System (LCS) capable of interfacing with the Local ANM Controller as detailed in figure 1;

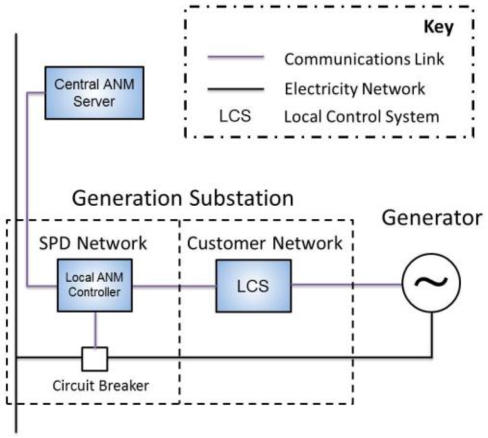

Figure1. ANM to LCS Interface Schematic

6.2 A Local ANM Controller shall be installed within the SP Distribution XX kV Switchroom.

6.3 With the exception of all final terminations at the Local ANM Controller, it shall be the responsibility of the Customer to supply and install all necessary physical connections between the LCS and Local ANM Controller.

6.4 All final terminations within Local ANM Controller shall be carried out by SP Distribution or appointed representatives.

6.5 The Customer shall provide a LCS capable of accepting a physical connection in one of the following formats;

6.5.1 Serial:
- RS-485;
- RS-232;

6.5.2 Ethernet:
- RJ-45;

6.5.3 Analog:
- 0-10V;
- 4 to 20mA;

6.5.4 Digital:
- 10-30 V DC;

6.5.5 Relay Outputs:
- 230V AC (Max);
- 1 A AC Resistive (Max);

6.6 Where a Serial or an Ethernet connection is to be used, the Customer shall provide a LCS compatible with one of the following protocols;

- DNP3.0 (Master/Slave RS-232/485)
- DNP3.0 (Client/Server TCP/IP)
- Modbus Master/Slave (RS-232/485)
- Modbus Client/Server (TCP/IP)
- IEC6870-5-101 Slave (RS-232)
- IEC6870-5-104 Server (TCP/IP)

6.7 The Customer shall provide an LCS with the capability for receiving control signals with a minimum 99.9% reliability and within 1 second of issue from Local ANM Controller.

6.8 The Customers LCS will be issued with a continuous Upper Real Power Set-Point Limit via the Local ANM Controller. The value shall be expressed as a kW value in the range of 0 kW to X kW. A continuous set-point shall represent the total allowable real power export from the generator. The Customer's LCS must restrict the total power production of the generators under its control to below this limit.

6.9 The Local ANM Controller shall maintain a watchdog, or heartbeat, with the Customer's LCS. The Customer shall provide a LCS capable of monitoring the watchdog, in order to allow the device to initiate failsafe behaviour upon loss of communication with the Local ANM Controller.

6.10 Upon loss of communication with the Local ANM Controller, the Customer shall ensure that the LCS can assume a failsafe state of operation that satisfies the requirements defined by SP Distribution. The LCS will not be permitted to return the generator to normal state of service until such time as loss of communication is resolved.

6.11 Following the restoration of a communication failure, the Customer shall provide a LCS capable of receiving initialisation data from Local ANM Controller without the need for user intervention.

6.12 An ANM control schedule shall be agreed prior to final commissioning.

6.13 As a minimum, the Customer shall provide a LCS capable of providing the following signal/data exchange as defined within **Table 2**;

Name	Type	Range/Units	Source	Destination	Update/ Frequency	Mandatory
Under ANM Control	Digital	0 to 1 (1=true)	LCS	ANM Controller	Local ANM Controller Demand	Yes
Local ANM Controller Watchdog Value	Analogue	Site Specific	ANM Controller	LCS	Every Minute	Yes
LCS Watchdog Value	Analogue	Site Specific	LCS	ANM Controller	Every Minute	Yes
LCS Fault Indication	Digital	0 to 1 (1=true)	LCS	ANM Controller	Local ANM Controller Demand	Yes
Upper real Power	Analogue	0 to rated real power	ANM Controller	LCS	Local ANM Controller	Yes

Set-Point Limit		(kW)			Demand	
Measured Real Power	Analogue	0 to 120% of rated real power (kW)	LCS	ANM Controller	Local ANM Controller Demand	Yes

Table 2

7. TECHNICAL REQUIREMENTS FOR SP DISTRIBUTION TO GIVE AN INSTRUCTION TO THE CUSTOMER

7.1 SP Distribution shall through its control equipment in an autonomous, semi-autonomous or otherwise in a manual fashion including verbal or written Instructions specify a level of Maximum Entry Capacity which may be less but not greater than the Maximum Entry Capacity as detailed in this Agreement

7.2 Upon receipt from SP Distribution of the specified level of Maximum Entry Capacity, the Customer shall reduce the flow of electricity from the Customer's installation to the SP Distribution's Distribution System in an autonomous, semi-autonomous or manual fashion to not exceed those specified levels and do so within the timescales specified by SP Distribution and detailed in Section 6 of this Appendix.

7.3 Should the Customer fail to act within the period specified by SP Distribution to achieve maximum flows of electricity below the specified levels SP Distribution shall be entitled to De-energise the Connection Points or isolate the Customer's generating equipment as is appropriate.