Distribution Network Operator Innovation Roll-Out Mechanism (IRM) Submission Pro Forma

Application to Innovation Roll-out Mechanism

Notice for adjustment to IRM Value

SP Distribution plc

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The body of this document includes references and footnotes. References are shown by a number in square brackets, for example "[1]". Footnotes are shown by a letter in square brackets, for example "[A]". References and footnotes are listed in Appendix A.

Distribution Network Operator Innovation Roll-Out Mechanism (IRM) Submission Pro Forma

Section 1: Application Summary Continued

Executive Summary

The SP Distribution (SPD) distribution network in Dumfries and Galloway is subject to an export constraint due to constraints on the transmission network. Until the completion of the Kendoon Tongland transmission reinforcement in 2023, the only option is for distributed generation (DG) to connect via the existing Load Management Scheme (LMS). The LMS disconnects DG to protect against transmission constraints. Given its basic operation, it frequently disconnects more DG than is necessary to mitigate transmission constraints and acts as a barrier to the development of new DG.

An alternative option to the LMS is to bring forward the installation of an active network management (ANM) scheme across Dumfries and Galloway – this is the project for which IRM funding is being sought. The ANM would manage the transmission network constraints in a significantly more refined way than LMS, resulting in fewer DG constraint actions and facilitating the connection of new DG. With the exception of one small scale trial, this would be the first multi-GSP ANM scheme in the UK, the first designed to alleviate transmission constraints using DG, and the first to interface with the system operator (SO). This makes it notably more complex and advanced than ANM schemes being promoted by other network licensees as business-as-usual solutions.

The IRM funding request is for £9.1m. The project would have benefits of £39.2m.

The roll-out of ANM in Dumfries and Galloway is currently planned for RIIO-ED2. Whilst there are significant benefits to consumers of bringing forward the roll out, there are no benefits to SPD and no funding has been included for this in SPD's RIIO-ED1 settlement. It is therefore very unlikely that the roll-out will be brought forward without IRM funding.

The proposed roll-out meets the core IRM licence requirement of the funding request being for the *roll-out of proven innovation* and Ofgem's IRM guidance document requirement of being at technology readiness level nine (TRL 9). It directly supports Ofgem and government policies of moving to a smarter and more flexible system.

This document is a Notice to propose a Relevant Adjustment, as required by licence condition CRC 3D.

Distribution Network Operator Innovation Roll-Out Mechanism (IRM) Submission Pro Forma

Section 1: Application Summary Continued

1.1 Application Title

Integrated Network Constraint Management for Dumfries and Galloway

1.2 Estimated Total Cost

£10.1m (2012/13 prices)

1.3 Total Funding Request

£9.1m (2012/13 prices). This funding request meets SPD's IRM materiality threshold.

1.4 Proposed IRM Adjustment

Table 1 sets out our proposed IRM adjustment during for RIIO-ED1 regulatory period.

	2018/19	2019/20	2020/21	2021/22	2022/23
SPD proposed revision to IRM values, £m	3.59	3.59	0.63	0.63	0.63

Table 1: SPD proposed Relevant Adjustment

1.5 Start date

The project is proposed to start 2018. The first Relevant Adjustment is proposed for regulatory year 2018/19.

1.6 End Date

The IRM funding for the project is proposed to end 2023. The last Relevant Adjustment is proposed for regulatory year 2022/23.

1.7 Application Summary

A large part of the SP Distribution (SPD) distribution network in Dumfries and Galloway is subject to an export constraint. This is because, at times where peak generation is coincident with low demand, there isn't sufficient capacity on the local 132kV transmission network. This is the case even with an intact transmission network. The long-term solution to this problem is a reinforcement project called the Kendoon Tongland reinforcement (KTR). This is due to complete Q3 2023.

Until the completion of the KTR project, no new distributed generation (DG) can connect in Dumfries and Galloway unless it connects under a load management scheme (LMS). The LMS protects against transmission constraints by disconnecting the DG when there is a transmission fault or a transmission constraint. There are [redacted] DG sites currently connected to the LMS, totalling [redacted] wind generation.

Whilst the LMS can be a useful tool, it is a basic solution – in a great majority of constraint instances, the LMS disconnects far more DG than is actually necessary to manage the fault. The unnecessary loss of zero carbon DG results in a carbon impact, and the resultant system imbalance has a cost impact for consumers. The LMS's inefficient operation also acts as a barrier to the connection of more zero carbon DG. Any method of managing the transmission constraint which reduces the DG that is taken off the system and facilitates the connection of more DG has carbon and financial benefits for consumers.

The alternative option to the LMS we are proposing in this submission is to install an active network management (ANM) scheme across Dumfries and Galloway – this is the Proven Innovation for which IRM funding is being sought.

The ANM scheme is a monitoring and control platform which sits above the physical network, and reduces constraints by ramping down the export from generators during times of system constraints. Whilst at a high level it does the same thing as the LMS (i.e. remove DG from the system to avoid constraints), it does so in a more targeted and intelligent way. This results in less DG being removed from the system to solve constraints compared to the LMS and less lost MWh of generation. It also reduces the barrier to new DG, especially to smaller-scale DG schemes including community projects.

The project for which IRM funding is being sought is to bring forward the roll-out of ANM (the Proven Innovation) across Dumfries and Galloway; the roll-out is currently planned for RIIO-ED2. This would be the first multi-GSP ANM scheme of this scale in the UK, the first designed to alleviate transmission constraints using DG, and the first to interface with the system operator (SO). This makes it notably more complex and advanced than ANM schemes being promoted by other DNOs as business-as-usual solutions.

The difference in operation between the ANM (the Proven Innovation) and LMS (the counterfactual) gives rise to a number of key benefits. These can be summarised as:

1. Carbon benefit. Reduced constraints to the [redacted] existing wind farms connected to the scheme, and the facilitation of the connection of more zero carbon generation, will give rise to carbon benefits.
2. Financial benefit. Reduced loss of DG from the system will lead to lower system imbalance costs. As these are ultimately recovered from consumers via their suppliers, this is a benefit to consumers. The [redacted] existing wind farms, which under the IRM are treated as consumers, will also have a financial benefit from reduced constraints.
3. Policy benefit. Enabling quicker connections for DG and using smart interventions to solve network constraints are in line with government policy and industry direction.

Points 1 and 2 above are the basis of the IRM funding benefits case that we make.

We understand that the intention of the IRM is to overcome commercial barriers to the deployment of network solutions that have benefits for consumers. Whilst there are significant benefits to consumers of bringing forward the roll out, there are no commercial benefits to SPD and no funding has been included for this in SPD's RIIO-ED1

settlement. There are no costs to SPD of continuing with the LMS scheme. As there are costs and risks yet no quantifiable commercial benefits to SPD of moving to the proposed ANM scheme, it is very unlikely that the roll-out will be brought forward without IRM funding.

The proposed roll-out meets the core IRM licence requirement of the funding request being for the *roll-out of proven innovation* and Ofgem's IRM guidance document requirement of being at technology readiness level nine (TRL 9). It directly supports Ofgem and government policies of moving to a smarter and more flexible system.

This document is a Notice to propose a Relevant Adjustment, as required by licence condition CRC 3D.

2 Application Description

2.1 Background to the problem

A large part of the SP Distribution (SPD) distribution network in Dumfries and Galloway is subject to an export constraint. This is because, at times where peak generation is coincident with low demand, there isn't sufficient capacity on the local 132kV transmission network. This is the case even with an intact transmission network. This means that further distributed generation (DG) cannot connect to the distribution network unless it connects under a load management scheme (LMS). The LMS protects against transmission constraints by disconnecting the DG when there is a transmission fault or a transmission constraint, but is far from an efficient solution and is acting as a barrier to the connection of more DG. Given this situation, there is now [redacted] DG that has connected but cannot fully utilise their connections (they are connected under the LMS), and a further 200MW of DG with connection agreements that are waiting to connect.

The distribution network connected to 11 grid supply points (GSPs) is affected by this transmission constraint. The 11 GSPs are Glenluce, Newton Stewart, Glenlee, Kendoon, Carsfad, Earlstoun, Tongland, Dumfries, Chapelcross, Maybole and Coylton. Their locations are shown in Figure 1 [1].

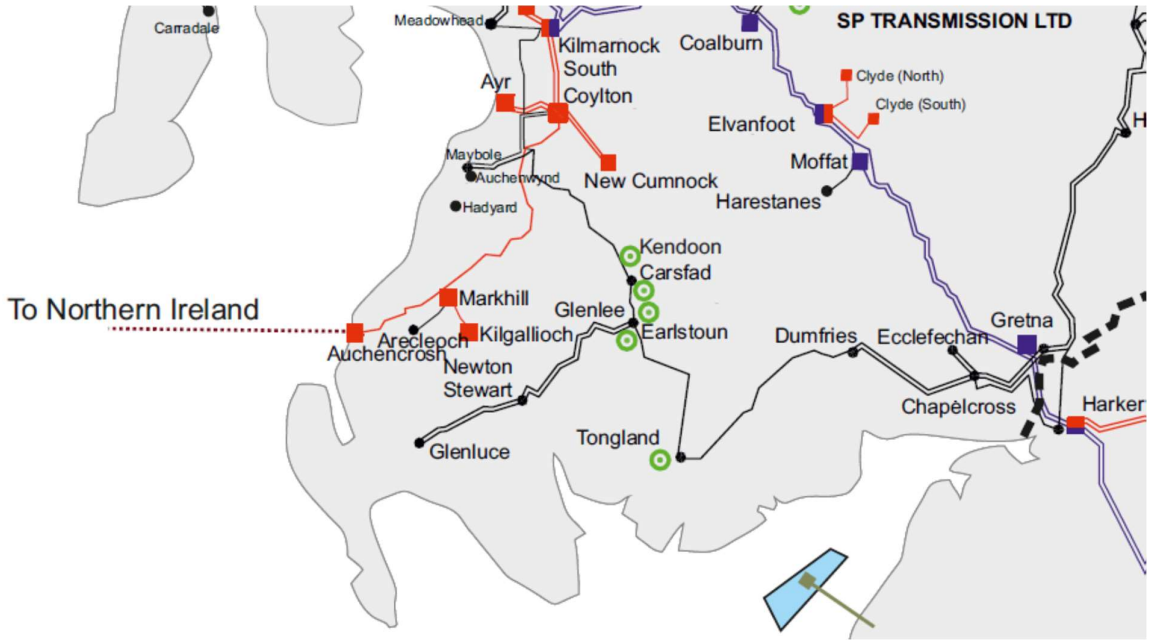

Figure 1: Transmission Network in Dumfries and Galloway, showing the 11 affected GSPs

The transmission constraint isn't caused by an individual circuit/substation, but results from a lack of capacity across a number of transmission circuits and substations in Dumfries and Galloway. This transmission constraint is not unexpected – Ofgem recognised the need for large-scale transmission reinforcement in this area at the time of SP Transmission's (SPT) RIIO-T1 submission in 2011. However further work was

required to identify the solution, so the project was categorised as Strategic Wider Works (SWW) and Ofgem approved some funding for the transmission reinforcement solution to be further investigated.

Connecting the DG was not the only driver of the need for a transmission solution: there is also 786MW of transmission generation with construction agreements with National Grid Electricity Transmission (NGET) waiting to connect to the SPT transmission network, the need to provide increased network security for the Moyle interconnector (shown in Figure 1 as the link to Northern Ireland), and the need to replace 132kV transmission circuits that are at end of life.

Following the RIIO-T1 decision, under the SWW process SPT developed and proposed three mutually exclusive reinforcement options to address these problems. These options ranged in cost from £190m-550m. These options were assessed by NGET, in its role of system operator (SO), and compared against a fourth option: the 'baseline' solution. This baseline solution was the minimum amount of transmission reinforcement required regardless of any constraint, as parts of the 132kV needed replacing anyway due to the condition of the aging assets. The cost of the baseline solution was estimated at £85m. The baseline solution provided an increase in capacity, but not sufficient capacity to fully alleviate the constraints that affect the DG.

NGET's analysis assessed the value of each reinforcement option over a 40-year period, by comparing its cost against the resultant reduction in constraint payments that NGET would have to pay. This created a value for each of the three reinforcement options and the baseline solution; these values were then compared to identify which of the four options was the best value. NGET published the results of its analysis in July 2016 [2]. NGET found that the baseline reinforcement option was the best value of the four options, i.e. the best value option was to build the baseline solution and, where it wouldn't fully alleviate the constraints, pay constraint payments when required. This was found to be better value over the 40-year period than selecting one of the reinforcement options that provided sufficient capacity to fully alleviate the constraints. The baseline solution was taken forward, and has evolved into the KTR (Kendoon Tongland reinforcement) reinforcement scheme which is currently being progressed. The completion date for the KTR project is 2023.

Prior to the completion of the KTR project, any DG wishing to connect to the distribution network in Dumfries and Galloway can only connect with Restricted Available Access (RAA). This is the policy that protects against transmission constraints by limiting the export capacity available to DG in certain network conditions. This is needed due to the shortage of transmission capacity before the KTR project is complete. Under RAA, DG is not guaranteed any export capacity and will be constrained to zero output when there is insufficient transmission network capacity. This may occur even when the transmission network is intact. Without RAA, no new DG would be able to connect to the Dumfries and Galloway distribution network before the completion of the KTR project as there would be no way to protect against the impact of DG on transmission constraints.

The July 2016 NGET assessment recommended the baseline solution, which would knowingly result in increased transmission constraints and the need for constraint management, and identified non-build commercial solutions would be required. However

the detail of what these non-build commercial solutions would be was undefined. This left the opportunity for the distribution licensee to develop a solution to alleviate the transmission constraint. However, there is no regulatory arrangement for distribution licensees to be funded for solutions for transmission constraints, even if the distribution solution represents the least-cost-to-consumer solution. This is not an ideal arrangement, and enacting a solution for which there is no cost recovery leads to insurmountable risks to the distribution licensee. Fortunately IRM funding presents a suitable opportunity to fund this project, but we are concerned that the lack of other RIIO-ED1 openers will lead to this issue recurring in the future, as transmission constraints are becoming an increasingly widespread obstacle to connecting DG.

2.2 The counterfactual

Currently, the only option for G59 DG [A] connecting under RAA and before the transmission reinforcement (KTR) is complete is via the LMS; this is the operational tool that facilitates the RAA policy. Some DG in Dumfries and Galloway is already connected via the LMS. This is the counterfactual (i.e. the business-as-usual situation) against which the IRM solution is assessed.

2.2.1 How the LMS works

The LMS scheme works by monitoring the transmission circuit loadings at possible constraint points on the network. It operates in three main stages:

1. If loading on a transmission circuit reaches 95% of rating, the LMS sends a warning signal to the connected DG to alert them that the system is operating close to full loading and it is up to them to ramp down.
2. If loading on transmission circuits reaches 100% of rating, the LMS sequentially trips off DG until the constraint is alleviated.
3. If a fault occurs on the transmission system and loadings are in excess of system capabilities the LMS disconnects all the DG connected to it to ensure security of the remaining network is maintained.

The stage 2 and 3 processes happen in less than one second. They need to happen this quickly as failure to remove excess generation increases the risk of cascade tripping of transmission circuits, which would result in a serious loss of supply to customers over a wide area.

DG disconnected by the LMS is only reconnected once a signal is manually sent from the network operator's control centre. Given the multiple network control centres and parties involved, it can take hours for the DG to be reconnected once the constraint has passed.

The cost of all the LMS equipment is split between the relevant DG and SPT – there is no cost or benefit to SPD of this arrangement.

2.2.2 Assessment of the LMS on electricity consumers

Whilst the LMS can be a useful tool, it is not a sophisticated solution. It doesn't have the capability to calculate the minimum volume of DG needed to be constrained to manage the fault (this value will constantly vary depending on local demand and generation levels). This means that:

- For stage 1, when the LMS sends a signal to DG to ramp down, it can't inform the DG what level to ramp down to. This means that either the DG ramps down too far, or doesn't ramp down far enough meaning that the circuit loading increases and the whole site then gets disconnected under stage 2. These both result in more MWh constrained than is necessary to solve the fault.
- For stage 2, whole sites are disconnected when the constraint might be solved just by ramping down a site. This results in more MWh being constrained than is necessary to solve the fault.
- For stage 3, all the DG connected under the LMS is disconnected, regardless of the actual capacity remaining in the network. This also results in more MWh being constrained than is necessary to solve the fault.

Under each stage the method of operation means that, in the great majority of instances, far more DG is disconnected than is actually necessary to manage the fault. For example for stage 3, if following a transmission fault the generation exceeds the network capacity by 20MW, but 100MW of DG is connected under the LMS, then 100MW is disconnected. This means that the system has unnecessarily lost 80MW of generation. This unnecessary loss of DG has two main adverse impacts for consumers:

1. There is a carbon impact. As all the DG currently connected via the Dumfries and Galloway LMS is renewable, LMS activation takes zero carbon generation off the system. NGET needs to replace this generation from elsewhere in the system to maintain frequency – analysis of historical NGET balancing actions shows that NGET will most likely call on coal or gas generation for this. In short, zero carbon energy has been taken off and replaced with fossil fuel generation.
2. There is a cost impact. Whilst there is no cost to NGET from disconnecting the DG (the DG is not compensated when it's disconnected by the LMS), there is a cost of the imbalance that the disconnection has created. This imbalance is ultimately recovered from consumers due to imbalance costs imposed on suppliers.

Therefore any method of managing the transmission constraint which reduces the generation that is taken off the system has carbon and financial benefits for consumers.

2.2.3 Assessment of the LMS on DG

The capital cost of the equipment required to connect to the LMS (which is paid for by the DG as it is categorised as sole use assets), and the impact it has on a DG's revenue stream by inefficient disconnections, mean that the LMS is a barrier to the connection of new DG. As the cost of the equipment required to connect to the LMS is a fixed capital cost, this barrier becomes more pronounced for smaller DG. This is in contrast to the reduced adverse impact that smaller generators have on transmission network constraints. In summary, the LMS presents a greater barrier to smaller generators, even though they individually have less of an adverse impact on the transmission constraints.

2.2.4 Summary of counterfactual

Given that the LMS option is available now to DG, yet none of the [redacted] contracted DG projects is pushing SPD for a connection, we conclude that none of the 200MW of contracted DG or any other new DG will choose to connect before 2024 if LMS is the only option for connection. This is the counterfactual against which the IRM solution is assessed: the 200MW of contracted DG not yet connected will not connect before 2024,

and the DG connected under LMS will remain on LMS until 2024, meaning it will be constrained off less efficiently than would result from a more refined approach.

2.3 The Proven Innovation

The alternative option to the LMS we are proposing in this submission is to install an active network management (ANM) scheme across Dumfries and Galloway – this is the Proven Innovation for which IRM funding is being sought.

The ANM scheme is a monitoring and control platform which sits above the physical network, and avoids constraints by ramping down the export from generators during times of system constraints. Whilst in simple terms it achieves the same thing as the LMS (i.e. remove DG from the system to avoid constraints), it does so in a more sophisticated and targeted way.

The LMS scheme simply monitors transmission circuit loadings to identify when there's a transmission fault or constraint, and trips off some or all the connected DG in response, based on a pre-programmed worst-case scenario. It has to use a pre-programmed worst-case scenario as it has no way of knowing the real-time power flows on the network, and thus what the actual real-time post-fault capacity of the network is. As the network nearly always has more post-fault capacity than for the worst-case scenario, it means that more DG is taken off than is necessary when the LMS activates.

Whilst the proposed ANM scheme would include intertrip functionality to manage constraints caused by transmission faults (this would be a first in GB), there are two key factors which differentiate the ANM scheme from the LMS:

1. An ANM scheme monitors the whole network in real time and has its own model of the transmission and distribution network. In combination this means that, by continuously running calculations, the ANM knows what the true capacity of the network is at any moment.
2. The ANM's controls can ramp individual DG sites down to a lower specific output level, rather than simply disconnecting all the generators, to give far more granular and targeted MW reduction.

This means that, when a constraint occurs, where the LMS would disconnect far more DG than is likely required, the ANM removes only the amount required to manage the constraint. When the constraint has passed, where it might take hours to manually send reconnection signals under the LMS, the ANM can instantly reconnect the DG. This approach results in less DG being removed from the system to solve constraints compared to the LMS and less lost MWh of generation – it is from this key point that a number of main benefits arise.

The AMN scheme has the ability to select which generators to reduce/disconnect first according to number of methods, for example last in first off (LIFO), the most technically efficient solution (the least MW removed from the system), the most commercially efficient solution (which takes into account generator constraint payments where these exist), and hybrids of these methods. This means that it has more functional flexibility than the LMS, and can operate under a range of future commercial models that may arise as GB moves towards a distribution system operator (DSO) model.

ANM presents a much reduced barrier to the connection of new DG compared to the LMS, due to the reduced revenue impact from less severe and frequent generation restrictions. The deployment of ANM at lower voltage levels will help manage the impact of smaller DG schemes on network constraints, allowing them to connect to the network with fewer restrictions or the need for them to be part of the LMS. This will reduce the barrier to community DG schemes and other small-scale DG.

In summary, the proposed ANM scheme would allow for a far more refined and targeted response than under the existing LMS. This means that less MWh of generation will be constrained off and more DG will connect to the Dumfries and Galloway distribution network than under the counterfactual LMS. These benefits of the ANM scheme over the LMS, and what these mean for consumers, are the basis of the IRM funding benefits case that we make. The factors that drive the benefits are summarised in section 2.5 and the benefits are set out in detail in section 4.

2.4 The total project

The roll-out of ANM in Dumfries and Galloway is currently planned for RIIO-ED2. The project for which IRM funding is being sought is to bring forward the roll-out of ANM (the Proven Innovation) across the 11 GSPs in Dumfries and Galloway which are subject to the current transmission constraint (see Figure 1 for the 11 GSPs). The project would consist of three main parts:

1. the ANM system itself;
2. other setup elements (e.g. staff training, alignment with existing control systems etc); and
3. ongoing operational activities (e.g. software licencing, maintenance, ongoing staff etc).

The following sections 2.4.1 to 2.4.3 describe these three parts in more detail, and section 2.4.4 provides a summary of the total project elements and those for which IRM funding is being requested.

This would be the first multi-GSP ANM scheme of this scale in the UK, the first designed to alleviate transmission constraints using DG, and the first to interface with the SO. This makes it notably more complex and advanced than ANM schemes being promoted by other DNOs as business-as-usual solutions.

2.4.1 The ANM system

The four key components of the ANM scheme are:

1. Measurement devices that are installed across the transmission network. There are two types: those that record current and voltage on transmission circuits and substations, and those that monitor transmission network circuit breakers. These monitor in real time and continuously send this information back to the central controller. This enables the central controller to know the state of the network in real time.
2. The central controller. This consists of the ANM software and the computing hardware on which it operates. This continuously calculates the spare capacity of the network in real time, using data received from the measurement devices and

pre-programmed information on the technical characteristics of the network assets. If a constraint is predicted or observed, the central controller calculates how to respond to that constraint (i.e. which generators should be constrained, and by how much), and issues those instructions out to the relevant generators. The central controller can also receive information from SPD's and NGET's network management systems. This information link can be used to update technical and commercial parameters of the network model and generation.

3. Generation site ANM equipment. This is the equipment that sits at each generation site that's connected under the ANM scheme, and implements the signals received from the central controller to reduce or disconnect the generation.
4. The communication network. The ANM scheme relies on a secure and reliable communications network to connect the measurement devices, central controller and generation site ANM equipment together. The communication network must have very low levels of latency (time delay; it typically needs to be less than one second) and very high uptime (typically greater than 99.9%). Firewalls are required between the generation sites, the ANM schemes, and the interfaces to NGET and DNO control systems, to protect against cyber risk. Fibre optic cables or satellite communication are usually the only communication methods that meet all the requirements.

IRM funding will be requested for elements 1, 2 and 4 of the above list (including the installation and commissioning costs associated with these elements). SPD consider that element 3 should be treated as 'sole use connection assets' under connection charging rules, so would be paid for by the generators that connect under the AMN scheme.

We want to specify an ANM scheme that has the capability to be rolled-out across the whole SPD licence area in the future, but without incurring significant cost that is not required for the roll-out in Dumfries and Galloway now. To get the right balance we are using the following approach:

- For the central controller, we will tender for one that has the capability to support the eventual roll-out of ANM across SPD's licence area. Whilst this will result in a controller that is marginally more expensive that one required just to manage Dumfries and Galloway, we consider this is overall better value for consumers than having to replace it with a more capable one when ANM is enacted in other parts of SPD's licence area.
- For the measurement devices and communication equipment, we will only install the quantity required to implement the ANM scheme in Dumfries and Galloway. This is because the cost of these elements is strongly proportional to the quantity required – to install these across the whole of SPD's licence area would significantly increase cost without providing any benefits for several years.

We consider this approach of using a central controller that can cover the whole SPD licence area, but using communications, measurement devices and generation site ANM equipment only needed for Dumfries and Galloway, strikes the correct balance between efficient expenditure and minimising costs to consumers.

Specifying the central controller to have the ability to manage the whole of SPD's licence area is one of a number of future-proofing functional capabilities that we will specify. These capabilities include the ability to order the constraint merit order using different methods (see section 2.3), the ability to link it to a customer portal (so ANM DG has visibility of when and why they've been constrained off) and the ability to link it to NGET's new Electricity Balancing System (EBS). Some of these capabilities might not be needed at the start of the Dumfries and Galloway roll-out, but they guard against the ANM scheme becoming quickly obsolete as future network operation models evolve. We believe that this functionality is especially important whilst there is so much uncertainty around how the networks will be operated in the future and the possible evolution of DSO and SO roles. This approach minimises the risk of the ANM becoming a stranded asset (and so protects the consumers' investment), and strongly links SPD's DSO vision – this scheme helps build the foundation for that transition (see section 3.3).

2.4.2 Other setup activities

In addition to the installation of the ANM scheme, there are a number of other activities that are required for the project to work:

1. Training of SPD district staff on the operation of ANM schemes
2. Development of network operational procedures
3. Updates to the SPD network management system
4. Updates to the NGET network management system
5. Development of commercial arrangements & policy
6. Customer engagement
7. Project management and project co-ordination
8. Procurement
9. Develop capacity registers for customers
10. Curtailment assessments
11. Factory site and user acceptance testing

2.4.3 Ongoing operational activities

Once the ANM scheme is operational, there will be a number of ongoing activities associated with its operation:

1. ANM software licence
2. ANM maintenance and 24/7 support from ANM provider
3. ANM scheme design modifications
4. ANM system alternations
5. ANM system configuration & tuning
6. Analysis and tuning for curtailment minimisation
7. Customer helpdesk
8. Vendor fixes, patches & upgrades
9. Routine reporting covering, availability for each generator, severity of constraint event, communications failures etc
10. Repairs including equipment replacement upon failure
11. Hardware upgrades
12. Web-based customer self-service portal for ANM performance information
13. End of life decommissioning/equipment recovery

In addition to the operational activities associated with the ANM scheme itself, SPD proposes to establish a new 'Smart Zone' team which will deliver the Dumfries and Galloway integrated ANM scheme along with the future wider roll out across the SPD licence area. The Smart Zone team will develop the foundations for a longer-term SP Energy Networks (SPEN) DSO business model. To ensure the success of the Dumfries & Galloway Smart Zone, it will require a multifunctional team, with core skills such as:

- Commercial & regulatory policy
- Market services
- Customer engagement
- Customer service – technical & analytical support
- System design engineers
- Delivery engineers – protection, communications and IT

2.4.4 The total project summary

Table 2 summarises all the elements of the total project which have been described in sections 2.4.1 to 2.4.3, and identifies for which elements IRM funding is being requested. All costs have been adjusted to 2012/13 values.

	Project component	Cost estimate	Included for IRM funding
ANM scheme	The central ANM controller	[redacted]	Yes – 100%
	Generation site ANM equipment	[redacted]	No
	ANM intertrip panel	[redacted]	Yes – 100%
Other setup activities	Detailed design	[redacted]	Yes – 100%
	Build & configure	[redacted]	Yes – 100%
	Installation, testing & commissioning	[redacted]	Yes – 100%
	Training of SPD staff	[redacted]	Yes – 100%
	SPEN network management systems	[redacted]	Yes – 100%
	Interface with NGET management systems	[redacted]	Yes – 100%
	Constraint management measurements	[redacted]	Yes – 100%
	SPD communications	[redacted]	Yes – 100%
	Smart Grid Team	[redacted]	Yes – 100%

Operational costs	ANM software licence	[redacted]	Yes – 100%
	ANM maintenance and 24/7 support	[redacted]	No
Total project cost		£10,106,577	
Total IRM funding request		£9,053,192	

Table 2: Summary of the total project and IRM funding request

SPD has a materiality threshold requirement of £6.47m in 2012/13 prices [3]. Table 2 shows that SPD's IRM funding request exceeds SPD's IRM materiality threshold requirement. The breakdown of the total IRM funding request into proposed Relevant Adjustments by year is in Appendix E.

2.4.5 Post IRM funding project viability

IRM funding is requested up until 2023, by which time the ANM scheme and centralised components of the system will be fully integrated into the SPD network. This will ensure the SPD licence area has the capability to roll our ANM solutions where required with our ED2 submission developed on the basis that ANM is BAU. Uptake of ANM connections is recognised as very much being customer driven, however we are not committed to any fixed costs beyond 2023. We expect that any OPEX associated elements will be well established in the market beyond 2023 to ensure the project and future BAU remains viable.

2.5 Consumer benefits of the IRM solution

This section summarises the factors that drive the consumer benefits of the IRM solution (the proposed ANM scheme) compared to the counterfactual (the existing LMS). The consumer benefits are assessed in detail in section 4.

Due to the differences between ANM and LMS, the proposed ANM scheme would allow for a more refined and targeted response to transmission faults than under the existing LMS. This means that less MWh of DG will be constrained off and more DG will connect to the Dumfries and Galloway distribution network than under the counterfactual LMS. In addition, ANM is more aligned with broader government and Ofgem policy objectives than the LMS.

It is from these key factors that the benefits of the ANM scheme compared to the counterfactual LMS arise – these are the factors that drive the benefits case in section 4. These key factors are set out in more detailed below and are summarised in Table 3.

1. **The [redacted] of DG already connected under the LMS.** [redacted] When there is a transmission constraint or fault, usually significantly more of this DG is disconnected than is required to manage the constraint. This is due to the functional limitations of the LMS. Under the ANM scheme, these sites would only

be constrained to the extent required to manage the network constraint. This results in three benefits:

a. **A carbon benefit**. As all the DG currently connected via the Dumfries and Galloway LMS is renewable, when the LMS activates it takes zero carbon generation off the system. NGET needs to replace this generation from elsewhere in the system to maintain frequency – analysis of NGET balancing actions shows that NGET will most likely call on coal or gas generation for this. In short, zero carbon energy has been taken off and replaced with fossil fuel generation.
b. **A cost benefit**. Whilst there is no cost to NGET from disconnecting the DG (the DG is not compensated when it's disconnected by the LMS), there is a cost of the imbalance that the disconnection has created. This imbalance is ultimately recovered from consumers due to imbalance costs imposed on suppliers.
c. **A revenue benefit.** These sites will directly benefit from reduced constraints as they will get more revenue from increased generation export.

2. **The 200MW of contracted DG yet to connect**. Under the counterfactual we assume that none of the contracted DG or any other G59 DG will connect before 2024. This is because of the barrier of the LMS to having a viable DG project. This position is supported by SPD's ongoing DG engagement – none of the contracted projects are pushing SPD for a connection. The ANM presents a much reduced barrier to connection as the reduced constraints increase generation revenue. We therefore assume that some new DG will connect under the ANM scenario. As all the contracted DG is zero carbon, connection of this DG would have carbon benefits for consumers. In addition to carbon benefits, DG developments directly financially benefit local communities – the 'local economic benefit'.
3. **Community DG**. Whilst the LMS is a barrier to all new DG, the effect is particularly pronounced for smaller-scale DG. This is because the cost of the equipment required to connect to the LMS is a fixed cost, so this barrier becomes more pronounced for smaller DG. The introduction of the ANM scheme would reduce the barrier to these community schemes. This has a direct benefit to these schemes by making them viable, and a carbon benefit as these schemes are typically renewable.
4. **Quicker more efficient connections (QMEC) alignment**. Ofgem's QMEC consultation recognised that capacity to accommodate new connections was often scarce and resulted in customers having to wait significant time periods and/or face the requirement to pay upfront for network reinforcement which in itself can affect whether or not projects progress. Our proposed use of ANM will be a significant step forward in demonstrating the extent by which capacity can be unlocked to accommodate new connections.
5. **Alignment with government policy**. The recently published Ofgem report 'Unlocking the capacity of the electricity networks' [4] examines the status of constraints across the GB networks and the progress being made by all network companies in addressing these. The report recognises the move away from traditional build solutions to that of more flexible connection arrangements. The use of ANM is essential if we are to deliver more timely electricity connections

secure low carbon future system. In addition, the joint Ofgem and Department for Business, Energy & Industrial Strategy (BEIS) 'A call for evidence' [5] highlighted that DNOs "are expected to more actively manage their networks". This recommendation has also been made by the National Infrastructure Commission.

6. **Alignment with policy direction for DNOs and distribution networks**. SPD is fully committed to and supporting the Energy Networks Association (ENA) TSO-DSO Transition project. This project aims to address the increasing need for coordination across all aspects of system and network operation, including in managing congestion, facilitating connections and active management of the system. The project focuses on the principles for the co-ordination and management of TSO and DNO constraints, ANM principles of access, high level commercial agreements required between SO, DNO and the customer for sharing of flexibility services, whole-system charging, consistent customer experiences, statement of works process, storage and the potential models for the distribution utilities as they transition to DSOs. The project aims to address the increasing need for coordination across all aspects of system and network operation, including in managing congestion, facilitating connections and coordinated active management of the system. The development of an integrated ANM Scheme for Dumfries and Galloway to manage transmission constraints is the starting model for adopting a whole system approach while building the foundations towards a DSO model.

Table 3 summarises these benefits. All these benefits are assessed in detail in section 4.

Factor	Counterfactual	IRM solution	Benefit of IRM
The [redacted] DG already connected to the intertrip	This is all disconnected when there is a transmission fault.	Less DG disconnected when there is a transmission fault, so less MWh of generation lost compared to counterfactual.	Carbon and financial benefit for consumers.
New DG at 33kV (all contracted DG is renewable)	None assumed to connect before the completion of KTR in 2023.	The ANM scheme would reduce the barrier to connection by reducing the time generators will spend constrained off with no compensation. This improves the financial viability of the projects. We assume some new DG will connect.	Carbon benefit to consumers of more zero carbon generation in the GB system. Financial benefit to consumers from local economic benefit. Quicker and lower cost connection of DG is aligned with Ofgem's QMEC policy.
New DG at 11kV	None will be allowed to connect before the completion of KTR in 2023.	DG <10MW now allowed to connect, significantly reducing the barrier to smaller-scale and community DG schemes.	Carbon benefit to consumers of more zero carbon generation in the GB system. Benefits to communities of being able to install their own domestic DG. Quicker and lower

			cost connection of DG is aligned with Ofgem's QMEC policy.
Holistic system planning	No holistic planning benefit of the intertrip	The ANM would be a solution designed by SPD in conjunction with SPT and NGET.	Alignment with government, Ofgem and industry policy direction.
Smarter operation of distribution network	The LMS is a basic operational tool.	ANM scheme has considerably more functionality, and facilitates moves to a smarter and more flexible system.	Alignment with government and Ofgem policy direction.

Table 3: Summary table of IRM ANM scheme benefits

3 Application Business Case

This section sets out the information required by Ofgem's 'Electricity Distribution Innovation Roll-out Mechanism submission guidance' (referred to hereon in as 'Ofgem's IRM guidance document', [6]). The information required for this section can be summarised as:

1. Why the innovation roll-out was not considered when SPD was developing its RIIO-ED1 business plan.
2. Why IRM funding is required.
3. The merits of undertaking the roll-out and how it links to long-term business changes/direction that the licensee wants to make.
4. Analysis of how the total costs have been estimated, and potential inaccuracies.
5. How the licensee will recover any granted funding through Use of System (UoS) charges.
6. How the licensee will ensure that the timing of apportioning these costs will be appropriately reflected in UoS charges and that only costs incurred during the RIIO-ED1 period will be recovered.

These requirements are covered off in sections 3.1 to 3.6 respectively.

3.1 Why the innovation roll-out was not considered in SPD's RIIO-ED1 plan

SPD's RIIO-ED1 business plan did not include a proposal to roll out ANM across Dumfries and Galloway. The key reason for this was that the Dumfries and Galloway transmission constraints, the key driver of the roll-out benefits now, was not a relevant consideration during formation of SPD's RIIO-ED1 bid. This is because, at the time of SPD's RIIO-ED1 submission, it was understood that these transmission constraints were going to be solved by large-scale transmission reinforcement. To understand this, the timeline for the formation of SPD's RIIO-ED1 bid needs to be compared with that for the RIIO-T1 SWW process.

In 2011 SPT submitted their RIIO-T1 proposal to Ofgem for approval. It identified the need for a significant transmission reinforcement scheme in Dumfries and Galloway. Given the scale of the proposed reinforcements and that further work to finalise the solution was required, it was categorised as a SWW project. Ofgem supported this position and approved funding for SPT to further develop the transmission solution. This was the agreed position for RIIO-T1, which started 1 April 2013.

SPD were preparing their RIIO-ED1 submission at the same time as the commencement of RIIO-T1. Given the positive position of the large-scale Dumfries and Galloway transmission reinforcement in SPT's RIIO-T1 settlement, SPD included the completion of a large-scale transmission reinforcement in the range of scenario assessments it did to produce its RIIO-ED1 bid. When a large-scale transmission reinforcement scheme in Dumfries and Galloway was included in analysis during SPD's RIIO-ED1 submission preparation, the benefits case for an ANM scheme in Dumfries and Galloway within the RIIO-ED1 period did not stack up. A funding request for ANM roll-out was therefore not included in SPD's RIIO-ED1 submission, which was submitted March 2014. This was not

challenged by Ofgem, and was the agreed position for RIIO-ED1, which started 1 April 2015.

After the commencement of RIIO-T1, SPT developed the transmission reinforcement options for Dumfries and Galloway and submitted these for assessment to NGET. It was only in July 2016, two years after the submission of SPD's RIIO-ED1 bid, when NGET published its analysis of the transmission reinforcement options, that it became apparent that large-scale transmission reinforcement in Dumfries and Galloway was not the optimal solution for the GB system.

The July 2016 NGET assessment recommended a solution which would knowingly result in increased transmission constraints and the need for constraint management, but did not recommend how those constraints should be managed. This left it to SPD to develop a solution to the transmission constraint. There is no regulatory arrangement for distribution licensees to be funded for solutions for transmission constraints, even where the distribution solution represents the least-cost-to-consumer solution. This is not an ideal arrangement and does not facilitate least-cost-to-consumer solutions; it will be especially problematic where there are risks and no benefits to the distribution licensee of enacting a solution (such as this case).

Fortunately, in this instance IRM funding presents a suitable opportunity as, without large-scale transmission reinforcement in Dumfries and Galloway, the benefits case for ANM on the distribution network becomes positive and it's the least-cost solution which involves the roll-out of proven innovation. This IRM funding window has been the first opportunity for SPD to propose a Relevant Adjustment to their price control, to take account of the changed benefits case for a licence area wide ANM-roll out.

In summary, SPD did not include for an area-wide ANM roll-out in its RIIO-ED1 submission as it did not have a positive benefits case when the assessment was carried out for the March 2014 RIIO-ED1 submission. This assessment assumed that a large-scale transmission reinforcement scheme would be going ahead. This was the best information available at the time, and was supported by Ofgem. Now that a large-scale transmission reinforcement scheme is not going ahead, the benefits case has become positive. This IRM funding window is the first opportunity for SPD to propose a Relevant Adjustment to redress this.

3.2 Why IRM funding

3.2.1 Meeting the intent of IRM funding in the RIIO context

Ofgem's 'Guide to the RIIO-ED1 electricity distribution price control' summarises the purpose of IRM funding: for "occasions where successful innovation does not provide sufficient benefits for the company to fund its roll-out, even though it would provide wider environmental benefits" [7]. Our arguments for IRM funding address these two key points:

1. there are clear benefits to consumers of rolling out this innovation; and
2. there are minimal benefits to the licensee of doing so.

Section 4 of this report sets out the benefits of the ANM solution. For an IRM funding request of £9.1m, the project delivers consumer benefits of £39.2m relative to the

baseline scenario (2012/13 prices). In addition, the ANM solution aligns with Ofgem's QMEC project, recommendations from the National Infrastructure Commission on the need for more active management of networks, and broader government policy on the need to move to smarter and more flexible networks. In summary, there are clear benefits to consumers of rolling out this innovation now.

Whilst there are significant benefits to consumers of rolling-out this innovation, there are no commercial benefits to SPD and no funding has been included for this in SPD's RIIO-ED1 settlement. There are no costs to SPD of continuing with the LMS scheme. It is therefore very unlikely that the roll-out will be brought forward without IRM funding.

This submission therefore meets the intent of what IRM funding was designed for – bringing forward innovation where it "does not provide sufficient benefits for the company to fund its roll-out, even though it would provide wider environmental benefits" [7].

3.2.2 Meeting licence condition CRC 3D

In addition to meeting the intent of Ofgem's IRM guidance document, this project meets the core intent of licence condition CRC 3D: the funding request is for the *roll-out of proven innovation*. These terms are defined in licence condition CRC 3D as:

- Roll-out: means the incorporation of a Proven Innovation into an Ordinary Business Arrangement.
- Proven Innovation: means an Innovation that the licensee can demonstrate has been successfully trialled or demonstrated either as part of its Distribution System or elsewhere.

The CRC 3D definition for 'Ordinary Business Arrangement' has a number of sub-options. The one most relevant for this IRM funding submission is:

- Ordinary Business Arrangement: means an operational practice that, whether singly or in any combination at the time of Notice given by the licensee under Part C of this condition [the time of Notice is the date of this IRM submission]:
  i. is not (except in the context of a trial) being used by a licensee in an adapted form or in a novel way; or
  ii. is not, in all material respects, something in respect of which another licensee is receiving, or has received, additional funding by virtue of the equivalent condition to this condition in that licensee's licence.

Meeting the definition 'Proven Innovation': ANM has been successfully trialled under several DNO innovation projects. Most relevant to this IRM funding bid is SPEN's Accelerating Renewable Connections (ARC) project. The ARC project was a Low Carbon Network (LCN) funded project that commenced in January 2013 and published its closedown report in March 2017 [8]. The project investigated a range of flexible technical and commercial solutions to accelerate the connection of renewable generation. Part of the project was the installation of two ANM schemes: one at Berwick GSP and one at Dunbar GSP. The ARC project implemented technical (ANM) and commercial solutions to accelerate the time to connect DG that would otherwise be held off whilst awaiting the completion of transmission system reinforcement works. The principle of

the ARC project is the same as for this IRM funding bid and so the experience is directly applicable. The project successfully delivered its key objectives by connecting ~100MW of DG RO (Renewable Obligation) accredited projects by March 2017 that would otherwise not have connected until completion of the transmission reinforcement works some 5 years later. Given that the ANM has been "successfully trailed", we consider that this IRM submission meets the licence definition of 'Proven Innovation'.

In addition to this licence requirement, the ANM scheme meets Ofgem's IRM guidance document [6] requirement of being at technology readiness level nine (TRL 9).

Meeting the definition 'roll-out': the ANM scheme for which IRM funding is being sought will become the only tool for managing DG to avoid transmission constraints in Dumfries and Galloway – there will be no backup scheme. This can only be achieved by it becoming the business-as-usual way of managing DG connections, i.e. it will be incorporated into an 'Ordinary Business Arrangement'. In addition, the proposed ANM project meets the requirement that it is not currently an 'Ordinary Business Arrangement' but will be after the roll-out: once installed, the ANM scheme will not be being used in "an adapted form or in a novel way" as it will have been designed specifically for this purpose. Based on this, we consider that this IRM submission meets the licence definition of 'roll-out'.

Based on our assessment of the IRM funding bid against these two definitions, we consider that this IRM submission meets the definition, and thus core intent, of the IRM licence requirement of the funding request being for the *roll-out of proven innovation*.

3.2.3 ANM as business-as-usual?

ANM schemes have been trialled under several LCN Fund and Network Innovation Competition (NIC) projects. Some DNOs have also included for ANM as a business-as-usual intervention within their RIIO-ED1 settlements. In this section, we explain why we consider that IRM funding is appropriate for this proposed ANM project.

The fundamental reason why we consider that IRM funding is appropriate is that, whilst the ANM scheme proposed has the same basic architecture as that already trialled and used by some DNOs, it is a significant step forward from those schemes in a number of key respects. These key differences are set out in Table 4.

Factor	ANM so far	ANM proposed by SPD
Network/geographic scale	Most existing ANM schemes are within a GSP or at a local distribution network level, and are incrementally added to if increased scale is needed.	11 GSPs will be the largest single roll-out in GB. The geographic area that the scheme will cover is significantly greater than any existing scheme.
Transmission constraints	Except for the small-scale ARC trial project, all existing ANM schemes are only managing distribution constraints caused by DG.	The proposed scheme will manage multiple transmission constraints using transmission network measurement points that are simultaneously caused by generation on both the transmission and distribution network – with the exception of the small-scale ARC trial project

		this is a GB first. This means that the ANM has to assess a much larger transmission and distribution network model for a far greater number of scenarios.
Interaction with TO and SO licensees	Except for the ARC trial, all ANM schemes are distribution only affairs – they control DG to manage constraints on the distribution network. There is no interaction with other network parties.	Using a distribution ANM scheme to control DG to manage transmission constraints and interact with both the transmission licensee and the SO is a GB first (with the exception of the ARC trial, which was a trial and did not involve the same level of DNO TO SO interaction).
Functional complexity	No existing scheme has merged ANM and intertrip functionality into a single control scheme. Usually they are two separate schemes which are not linked together. Single method of stacking the D constraint merit order.	This is the first scheme in GB that merges the dynamic control of an ANM scheme with intertrip instant post-fault protection functionality in a single control scheme. ANM capable of multiple ways to stack the DG constraint merit order.
Post event reporting	Except for the Orkney ANM scheme, generators connected under existing ANM schemes have to contact the DNO to find out if they were constrained, and why.	The ANM scheme will have the functional capability of being linked to a portal which generators can access to getting reporting on any ANM constraints. It will be the first ANM scheme to have a business-as-usual dedicated customer interface team.

Table 4: Comparison of existing ANM schemes to the proposed ANM scheme

The increased network scale, both in terms of number of GSPs and the inclusion of both transmission and distribution network, considerably increases the number and complexity of the possible constraint scenarios and the potential actions available to the ANM scheme. This means that the constraint scenarios that the proposed ANM will manage are significantly more complex than those managed by other ANM schemes.

In additional to the increased complexity caused by the scale and number of parties involved, the proposed ANM scheme also has significantly more functional capability than existing ANM schemes. The incorporation of an intertrip capability into the ANM scheme to create a single fully coordinated network/generator control function is a GB first. Functional capability is further added to by the ability to choose which generators to reduce/disconnect first based on a number of methods: LIFO, the most technically efficient solution (the least MW removed from the system), the most commercially efficient solution (which takes into account generator constraint payments where these exist), and hybrids of these methods.

In summary, whilst at a high-level the proposed ANM scheme operates in the same manner as existing ANM schemes, the increased scale, number of network parties involved, operational use, and functional flexibility make it considerably more complex

and advanced than other schemes being deployed in GB. It is therefore appropriate to apply for IRM funding for this proposed ANM project.

3.3 How the roll-out links to SPD business changes

The energy sector is experiencing an unprecedented level of change with increasingly decentralised energy generation and significant changes to the way our customers interact with the network. In addition, the electricity network will also need to be flexible enough to facilitate the electrification of heat and transport in order to meet challenging CO_2 emission targets.

To address these challenges we released 'Our DSO Vision' [9], outlining our aspiration to transition from a DNO to a DSO. This transition has also been consulted upon by BEIS and Ofgem in their Call for Evidence on Flexibility [5] and is now the objective of a major industry workstream under the ENA (the TSO-DSO Transition project - see section 2.5).

Within the 'Our DSO Vision' document we outline the key enabling technologies to facilitate the transition to a DSO, among them we cite enhanced network monitoring and expanded network control (the two functions of ANM) as key enablers. This project will be a key enabler for us to realise our vision of transitioning to a DSO.

3.4 Cost estimations and potential inaccuracies

This section summarises how the costs were estimated, and the potential for inaccuracies in those costs.

Whilst we have experience developing ANM projects, given the unprecedented scale and functional complexity of the proposed ANM scheme we worked with an ANM provider to help estimate the ANM capital and operational costs. During this work, we were careful to ensure that we focussed on what functional capability was required and estimated costs to achieve that, rather than focussing on their specific solution. This approach gives us good cost estimates without limiting us to a single supplier. We will tender the ANM scheme, to ensure that we get the best value scheme that meets the project requirements.

All other capital and operational costs we developed using internal expertise and experience of these cost elements. As with the ANM equipment, we will tender these elements where possible to ensure that we get best value.

3.5 Recovery of IRM funding through UoS charges

The requested IRM funding takes the form of an adjustment to the SPD regulatory settlement for RIIO-ED1. Following the terms of our Electricity Distribution Licence, we will then recover these costs through UoS charges applied to all our customers.

3.6 Recovering costs within the ED1 period

This bid only seeks to request funding for costs incurred during the RIIO-ED1 period. Capital and operational costs beyond the end of RIIO-ED1 are excluded from this funding request.

We will ensure our IRM expenditure will be appropriately reflected in network charges by including the IRM expenditure in the Price Control Financial Model (PCFM). The PCFM is a

Financial Instrument governed by the RIIO-ED1 conditions in the distribution licence. Our IRM forecast expenditure will increase our allowed costs in the PCFM model. The model compares our allowed costs with actual expenditure and determines the appropriate revenues we should seek to collect each year. Therefore this model adjusts our network charges for any variance in our IRM expenditure between forecast and actual expenditure.

4 Evaluation Criteria

This section sets out the detail of how this IRM funding bid meets the IRM criteria. For convenience, we have followed the criteria labelling used in Ofgem's IRM guidance document [6]. Appendix D sets out the assumptions and calculations used to calculate the carbon and financial benefits.

4.1 The basis of the carbon and financial benefits calculations

Carbon and financial benefits from the ANM scenario fundamentally arise due to less MWh constrained and more MWh generated by DG than compared to the LMS. These values were calculated and are shown in Table 5 (for the full calculation process please see Appendix D). A positive value indicates more MWh generated/constrained under the ANM scheme; a negative value indicates more MWh generated/constrained under the LMS. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024-27	2027/28	2028/29	2029/30	2030/31
Δ MW connected	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Δ Total MWh generated	174,004	174,004	174,004	174,004	174,004	0	10,161	174,004	174,004	174,004
Δ Total MWh constrained	-5,873	-5,873	-5,873	-5,873	-5,873	0	-10,161	-5,873	-5,873	-5,873

Table 5: the difference between the IRM and counterfactual

Table 5 shows that from 2019/20 to 2023/24 more DG is connected to the system under ANM than under the LMS. This results in more MWh generated (due to more DG being connected) and lower constraints (due to the increased sophistication of the ANM scheme constraint management).

From 2024/25 the difference between the two schemes reduces to zero. This reflects that the KTR project is completed at the end of 2023/24, and results in sufficient increased transmission capacity that no DG is constrained and new DG connects under the LMS scenario such that there is an equal volume of DG under the two scenarios. Therefore there is no difference between the ANM and LMS schemes.

From 2024/25 onwards, DG continues to connect to the system at the same rate and volume under both scenarios (so the ΔMW values for these years are 0). In 2027/28 the level of new DG in both scenarios has increased such that transmission constraints are triggered for the LMS scenario but not the ANM scenario. Given this constrain, we assume that no new DG connects under the LMS scenario from this point forwards (for the same reasons why we assume that no new DG will connect under the LMS scenario from now until 2023).

In 2028/29 new DG only connects under the ANM scenario (as the LMS scenario has become constrained in 2027/28). We assume broadly the same project economics for DG as before KTR, so the network fills to the same volume of DG. All NGET Future Energy Scenarios (FES) scenarios show increasing DG in the 2020-30 period and

Dumfries and Galloway has good wind resource, it's a reasonable assumption that DG will connect to the network in this period.

We have not modelled benefits beyond 2030/31 as we assume that this is the date by which AMN would be in place in Dumfries and Galloway under the counterfactual scenario. This means that there are no differences between the two scenarios after 2030/31.

The values in Table 5 are the values from which the carbon and financial benefits are calculated (sections 4.2 and 4.3 respectively).

4.2 Criteria a: will deliver additional carbon, environmental or any other wider benefits

Licence condition CRC 3D.8(a) requires that the innovation roll-out for which IRM funding is requested "will deliver Carbon Benefits or wider environmental benefits". Carbon Benefits is defined as being a contribution to DECC's Carbon Plan of 2011 [10]. This section sets out the carbon and environmental benefits, by reference to the Carbon Plan and the RIIO-ED1 CBA tool where appropriate.

4.2.1 Carbon benefit

As we assumed that all the new DG that would connect under both scenarios would be renewable, we calculate the carbon benefit using the MWh values from Table 5 and the 'electricity GHG conversion factors' (tonnes CO_2/MWh) in the RIIO-ED1 CBA Tool. These calculations are set out in Table 6. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024-27	2027/28	2028/29	2029/30	2030/31
Δ Total MWh generated	174,004	174,004	174,004	174,004	174,004	0	10,161	174,004	174,004	174,004
GHG conversion factor, tonnes CO_2/MWh	0.445	0.430	0.416	0.401	0.387	~	0.329	0.314	0.300	0.285
Resultant CO_2 benefit, tonnes	77,408	74,886	72,364	69,841	67,319	0	3,342	54,708	52,186	49,663

Table 6: ANM scheme tonnes CO_2 benefit

From Table 6 it can be shown that the proposed ANM scheme results in a total carbon benefit of 521,717 tonnes CO_2 in the period to end of 2030/31.

4.2.2 Contribution to the Carbon Plan

The 2011 Carbon Plan [10] is the government's strategy for the UK to achieve our legally binding target of an 80% reduction in greenhouse gases by 2050. The Carbon Plan uses a series of sequential five-year Carbon Budgets to breakdown this target into shorter-term targets. This project makes a direction and material contribution to the Carbon Plan and the third, fourth and fifth Carbon budgets (which cover the period 2018-2032).

4.3 Criteria b: will provide long-term value for money for energy consumers

Licence condition CRC 3D.8(b) requires that the innovation roll-out for which IRM funding is requested "will provide long-term value for money for electricity consumers". Ofgem has confirmed [11] that 'electricity consumers' in this instance means any distribution connected users, i.e. demand and generation. Ofgem has confirmed that 'energy consumers' has the same meaning as 'electricity consumers' [11] – these two terms are used interchangeably in this submission. Ofgem's IRM guidance document [6] states that licensees should use the RIIO-ED1 CBA tool as part of their justification. This section sets out the value for money benefits for consumers, using the RIIO-ED1 CBA tool where appropriate.

Most benefits, unless stated otherwise, arise from the fact that:

1. ANM is a more refined intervention than LMS, meaning that less MWh of generation from existing generators is constrained under ANM than under LMS.
2. ANM is a lower barrier to connection than LMS, and so will result in more DG connected to the system. Based on contracted DG capacity, we consider that all this DG will be renewable.

4.3.1 Quantitative benefits

There are five main quantifiable financial benefits associated with the roll-out:

1. The financial value of the carbon benefit
2. The financial value of reduced system imbalance
3. Value to existing DG of reduced constraints
4. The local economic benefit
5. The value of future avoided expenditure

These are explained in more detail below. For assumptions and information on these calculations please refer to Appendix D.

The financial value of the carbon benefit. This benefit increases proportionally to the MW of DG connected to the system, and the resultant energy generated, as all the DG contracted to connect is renewable. Section 4.1 shows that 521,717 tonnes CO_2e will be avoided due to the ANM scheme, using the value of carbon set out in the RIIO-ED1 CBA tool, this equates to a total project benefit of £21.3m.

The financial value of reduced system imbalance. When DG is constrained off the system, it causes an imbalance. This imbalance has a cost, which is imposed on suppliers. As suppliers recover their costs from consumers, these imbalance costs are ultimately passed to consumers. Therefore, less MWh constrained is a consumer benefit as it means lower costs recovered from consumers.

To calculate this benefit, we need to know the cost of the imbalance is. For this we used the System Imbalance Price (SIP) from the Balancing Mechanism (BM), as the SIP is a good reflection of the cost of imbalance. It varies every settlement period and has a high degree of volatility. Given this, we used the average values from 2016, which was £41.01/MWh.

Using this value and the value from constrained MWh values from Table 5 we could calculate the total difference in imbalance costs between the ANM and LMS scenarios. We calculated the proposed ANM scheme results in imbalance savings of £2.2m in the period to end of 2030/31.

Value to existing DG of reduced constraints. [redacted] These are all RO accredited sites. A MWh of generation is worth ~£81/MWh (2012/13 price, this is split roughly evenly between the Renewable Obligation Certificate (ROC) value and the value of the electricity). These sites are classed as 'electricity consumers' for the purpose of licence condition CRC 3D. Under ANM the total additional generation output to 2030/31 compared to under LMS is calculated to be 91,499MWh. This gives a benefit of £7.4m in the period to 2030/31.

The local economic benefit. With rare exceptions in very remote areas, communities local to DG developments are all customers of the distribution network. The development of DG brings economic benefits to the local community. These can be classed in two ways: energy financial benefits (usually in the form of developers offering discounted electricity to local residents) and non-energy financial benefits that arise from presence of local development (for example, increased expenditure in shops and hotels, and employment of local suppliers and contractors). Energy benefits are dependent on which company is developing the DG; we have therefore not included these in our quantitative assessment. Non-energy benefits are intrinsically associated with the development of DG projects and there are a number of case studies which have quantified these based on assessment of a large number of projects. We have therefore included these in our quantitative assessment.

To form a value for the local economic benefit we assessed a number of sources [12][13][14][15]. Based on these, we use a local economic benefit value of £0.28m/wind turbine in our cost benefit analysis (CBA). The new DG connections in our ANM scenario consist of a total of [redacted] wind turbines, giving a total value of £7.28m (in 2012/13 prices).

Under the ANM scenario this benefit is assumed to arise in 2019/20. Under the LMS scenario, we assume this DG would connect at 2024/25. Therefore the benefit of the ANM over the LMS isn't the absolute value of the local economic benefit, but the time-value-of-money benefit of moving this benefit forward. This effect is repeated towards the end of RIIO-ED2 when a second tranche of generation connects earlier in the ANM scenario. This equates to total economic benefit of £2.5m for the ANM scenario compared to the LMS scenario for the period to 2030/31.

The value of future avoided expenditure. Under a business as usual scenario, ANM would be implemented late in RIIO-ED2. To ensure that this option is comparable to the baseline, these costs are treated as avoided expenditure.

An efficiency factor has been adopted to represent the fact that ANM will become cheaper as it matures. We have used an efficiency factor of 75%, i.e. at the end of RIIO-ED2 ANM will be 75% of the cost it is now. Given that the majority of costs of an ANM scheme are items that are mature (e.g. fibre optic cables), and so unlikely to

significantly decrease, we consider that this is ambitious, meaning we are likely understating this benefit.

This equates to an avoided expenditure benefit of £6.8m (in 2012/13 prices) for the ANM scenario compared to the LMS scenario.

Summary. The total quantitative benefits to electricity consumers of the proposed IRM roll-out compared to the counterfactual in the period to 2030/31 is calculated to be £39.2m (2012/13) relative to the baseline scenario. This is significantly in excess of the level of IRM funding requested.

Relative to the baseline scenario, the NPV returns based upon payback periods of 16 years, 24 years, 32 years and 45 years are £18.3m, £18.2m, £18.1m and £18.1m respectively.

4.3.2 Qualitative benefits

In addition to these quantifiable benefits for electricity consumers, there are four benefits to electricity consumers that we have not attributed a £ value to, but are still important to include. These are:

1. Empowerment to communities
2. Enabling greater participation in the BM
3. Market benefit of more generation
4. Building capability for the future

Empowerment to communities. The existing LMS presents a barrier to DG projects (see section 2.2.3 for an explanation). As the cost of the equipment required to connect to the LMS is a fixed cost, this barrier becomes more pronounced for smaller DG. As most community schemes are large enough to be G59 scale [A] (meaning they must connect to the LMS) but not large enough to bear the costs of connecting to LMS, they are particularly impacted by the current LMS scheme. The ANM reduces this barrier in two ways:

1. The ANM gives greater visibility and control of the distribution network. This means that, where even small DG have to connect to the LMS, they don't need to connect to the ANM scheme at all as their impact on transmission constraints can be mitigated.
2. Where DG is of a scale where it still needs to connect to the ANM, the equipment required to connect to the ANM scheme is lower cost than that needed to connect to the LMS scheme.

In summary, the LMS scheme is a real barrier to smaller DG schemes, such as community schemes. Depending on project size, the ANM will reduce or remove this barrier. This will allow community and small-scale DG schemes to develop.

Enabling greater participation in the BM. The ANM scheme's communication network facilitates to participation of connected DG in the BM. Whilst active participation [B] of DG in the BM historically has been limited [C], that is likely to change. New DG connecting to the system will not be RO accredited, meaning their bid offer price can be much lower. In addition, the revenue from ancillary sources will likely become

increasingly important to their business model. Given this, new DG can be a new source of lower cost balancing and constraint services for NGET [D]. This is good not only for lower cost balancing services but also due to necessity – many traditional providers of balancing services are coal plant, which are closing, so finding new ancillary service providers is essential for system stability and security.

Market benefit of additional generation. Increasing the level of renewable generation connected to the system increases competition and removes higher marginal cost plant from the system. This should result in reducing wholesale prices over time, which will be to the benefit of consumers.

Building capability for the future. In November 2016, BEIS and Ofgem issued a joint 'A call for evidence' [5]. Within this they highlighted the importance of a smart, flexible energy system, highlighting:

- for consumers, smart energy technology and processes have the potential to deliver lower bills and new services;
- for the current and future energy system, greater flexibility will help deliver security of supply;
- its ability to facilitate simpler integration of new, low carbon technologies; and
- how smarter energy systems are complementary to bringing forward new generation.

We consider the proposed ANM solution will significantly advance the development of a truly smart, flexible energy system in Dumfries and Galloway. This directly supports Ofgem and government policy and aligns with SPD's vision of transitioning to the DSO model.

4.3.3 Ex-post assessment of benefits

The funding through IRM will provide SPD with the learning and experience gained from the first installation of an ANM scheme of this scale, complexity and purpose. It will introduce the principles and procedures behind the implementation, maintenance and operation providing accurate project cost information to inform future projects.

The use of ANM technology is attractive to DG seeking to connect that would otherwise be subject to reinforcement and lengthy timescales. ANM offers a solution to connect with greater flexibility without the need for reinforcement works. This project will allow SPD to gain greater familiarisation of the technology, generating experience and confidence to the benefit of our customers and other DNOs.

Once the overall cost of implementing large scale ANM schemes is well understood and part of business-as-usual, case-by-case assessments will ensure that future solutions can be better optimised in terms of technical and financial efficiency. Through the increased implementation of ANM technology, it would be reasonable to also anticipate the market costs to decline – further improving the supporting business case and, ultimately, improving value for money for consumers.

Our proposal for the ANM Scheme in Dumfries & Galloway will continue to facilitate DG, without which we would see a shift towards increased transmission connections away from local demand. It will also deliver the key foundations to the development of a DSO

model. Our proposed approach will also ensure that all necessary centralised infrastructure is in place to deliver the requirements for the integrated ANM Scheme in Dumfries & Galloway and facilitate the roll out of ANM across the SPD licence area.

It is recognised that the most economically efficient method to satisfy demand is by utilising plants with the lowest marginal cost of generation, for example wind and solar plants, zero marginal cost plants. In terms of system balancing, the most efficient thermal plant is next to be brought on line, and as customer demand increases towards peak the least efficient, and most expensive fossil plant, typically will get used. The deployment of ANM in the Dumfries and Galloway network and across the SPD licence area will ensure that more zero marginal cost generation can be connected to the system.

4.4 Criteria c: will not enable the licensee to receive additional commercial benefits which are greater or equal to the cost of implementing the Proven Innovation

Licence condition CRC 3D.8(c) requires that the innovation roll-out for which IRM funding is requested "will not enable the license to receive commercial benefits from the Roll-out within the remainder of the Price Control Period (for instance, where the Roll-out of a Proven Innovation will lead to cost savings (including benefits from other incentive mechanisms) equal to or greater than its implementation costs within the Price Control Period)." Ofgem's IRM guidance document [6] set out further information on this. This section sets out the evidence to meet this criterion.

4.4.1 Impact on existing RIIO-ED1 incentives

We have considered the impact of the proposed project on our existing RIIO-ED1 settlement and the incentive mechanisms that it contains. To do this we identified incentive mechanisms that might be affected by this project. We identified three possible mechanisms:

- Losses. The 11 GSPs for which the ANM scheme would be rolled out is marginally a net import area. However the addition of new DG under the ANM scheme would cause it to become a net export area. Given this, there is likely to be little material impact on I^2R losses caused by increased utilisation of the network. Most relevant to this, there is no calculated losses incentive in RIIO-ED1 so we will not be rewarded or penalised. Therefore we will not benefit from this incentive mechanism.
- Broader Measure of Customer Satisfaction (BMCS). The installation of ANM may marginally increase customer satisfaction, which would benefit SPD. However the very limited number of customers involved, and the fact that they are of a scale where they would have a dedicated SPD point of contact (and so would likely already have a high measure of customer satisfaction), means that this will not result in any material benefit. Therefore we consider that will not benefit from this incentive mechanism.
- Incentive on Connections Engagement (ICE). Whilst the deployment the ANM scheme in Dumfries and Galloway will facilitate more generation and expand on our ICE commitment to deliver flexible connections, there will be no direct benefit to SPD under ICE as it is a penalty only mechanism.

In summary, we consider that the proposed project will not cause us to materially benefit from any of our RIIO-ED1 existing incentive mechanisms.

4.4.2 Cost control

SPD will ensure that our SAP financial system will use a separate cost control centre for the IRM project allowing all applicable project costs to be separated from other investment programmes. This will also allow us to report costs accurately within the annual Regulatory Reporting Pack (RRP) for IRM as per the Regulatory Instructions and Guidance (RiG) documentation. This approach will further ensure that only those costs incurred in line with the maximum funding allowance will be passed through via UoS charges

4.5 Criteria d: will not be used to fund any of the ordinary business arrangements of the licensee

This section sets out the information required to meet criteria d in Ofgem's IRM guidance document [6], bar the request for the licensee to evidence how the roll-out will enhance competition in the market (this is set out in section 4.8.1). By meeting this criterion, we consider that we are also meeting licence condition CRC 3D.8(d), which requires that the IRM funding requested "will only be used to fund the Roll-out of Proven Innovation."

Arrangement as defined in CRC 3D. The ANM scheme for Dumfries and Galloway is not currently classed as an ordinary business arrangement. The complexity of the ANM scheme for Dumfries and Galloway does not currently exist into our existing business activities for roll-out and the scale of the design, modelling, commercial solutions and delivery programme required for roll-out exceed that used in our existing business activities or ARC project. Whilst it is envisaged that SPD will engage with an external vendor for the ANM solution via tendering activity, we fully expect to develop our own knowledge and experience on ANM solutions for the benefit of the entire SPEN network and other network companies. This in turn should enhance competition in the market place for technical solutions to deliver ANM requirements. We would expect that vendor licencing costs for example to fall as more network companies deploy ANM as "business-as-usual". Whilst this has not been reflected in the CBA, as the use of ANM becomes greater, we would expect that there is an increased benefit.

4.6 Criteria e: involves Proven Innovation and warrants limited funding support

This section sets out the information required to meet criteria e in Ofgem's IRM guidance document [6]. This requires us to demonstrate that what the roll-out is seeking funding for is innovative and not already an Ordinary Business Arrangement, and the method we will use to ensure that the innovation meets TRL 9.

4.6.1 Is innovative and not an ordinary business arrangement

The ANM scheme is not currently classed as an ordinary business arrangement. The CRC 3D definition for 'Ordinary Business Arrangement' has a number of sub-options. The one most relevant for this IRM funding submission is:

- Ordinary Business Arrangement: means an operational practice that, whether singly or in any combination at the time of Notice given by the licensee under Part C of this condition [the time of Notice is the date of this IRM submission]:
  i. is not (except in the context of a trial) being used by a licensee in an adapted form or in a novel way; or
  ii. is not, in all material respects, something in respect of which another licensee is receiving, or has received, additional funding by virtue of the equivalent condition to this condition in that licensee's licence.

The proposed ANM scheme cannot currently be classed as an 'Ordinary Business Arrangement' as it fails part i – we are proposing to use the ANM in a novel way. No licensee is currently using ANM in the manner proposed by this project – it would be a novel use. For more information on how this ANM scheme is novel and different to ANM schemes used to-date, please see section 3.2.3.

In addition to meeting the requirement of not already being an 'Ordinary Business Arrangement', no funding has been included for this in SPD's RIIO-ED1 settlement, i.e. SPD is not already funded for the roll-out. As there is no risk or cost to SPD of sticking with the existing tried and tested LMS scheme, and there are costs yet no quantifiable commercial benefits to SPD of moving to the proposed ANM scheme, the roll-out will only happen with IRM funding. Despite the benefits of the roll-out to electricity consumers, the roll-out will not happen without IRM funding.

4.6.2 Ensuring the Innovation is TRL9

We will be going out to tender for the ANM solution. As part of the tendering process, we will require potential vendors to evidence that their proposed solution has been successfully deployed before – a key test of TRL 9 and licence condition CRC 3D's definition of Proven Innovation. We will assess the evidence they provide against this tendering requirement to determine whether their proposed ANM solution meets TRL 9 and licence condition CRC 3D's definition of Proven Innovation.

4.7 Criteria f: is ready to be rolled-out with any funding being used in the price control period

This section sets out the information required to meet criteria f in Ofgem's IRM guidance document [6].

The learnings from our ARC project places SPD in a strong position to successfully transition the Proven Innovation into business-as-usual. SPD is already very technically skilled in the field of installing, maintaining and repairing its infrastructure. SPD is also leading on the commercial innovation changes required to manage the ever changing relationship across the transmission/distribution boundary. SPD recognises the changing use of the network away from the traditional model where the power flows have historically followed predictable demand profiles and load growth patterns are now much more active and volatile.

SPD has a strong track record in creating both customer and business benefits through: (i) the application of innovative technical and commercial solutions developed through learnings from ARC (whereby we have facilitated 113MW across 13 individual generation projects); (ii) improved visibility of our network through the deployment of targeted

network monitoring; and (iii) the application of dynamic transformers ratings resulting in 20% more capacity than would have been achieved through conventional planning assumptions.

Taking into account the technical challenges and additional responsibilities that SPD faces in order to roll out an integrated ANM scheme across the Dumfries and Galloway network, SPD is very well positioned to deliver this undertaking. We do not believe a radical change is required, but instead a progressive development of new skills.

4.7.1 Project Plan and Resources

A project plan has been developed and included as Appendix F.

We have also assessed the resource required to deliver the roll-out across the Dumfries & Galloway network and ultimately across the entire SPD licence network area. The costs have been included within the CBA and do form part of the funding request. Whilst SPD has successfully trialled ANM under the ARC project, key to the deployment of ANM is the establishment of a team that is both multi-functional and multi–skilled. This approach will not only support SPD's transition to the DSO model, but also ensure that customers have access to a centralised Smart Grid Management & Services Team providing new services such as forecasting, constraint analysis, and supporting the development market services. Our learnings from ARC have highlighted the importance of continual engagement with customers connected under ANM throughout the lifecycle of their project.

4.7.2 Risk register

A risk register had been developed and is presented in Table 7.

Risk	Risk Description	Mitigation Comments
Integration Risk	Dynamic network constraints & volume of data can lead to IT and network integration issues Approach not adopted by other parts of business Integration of existing data sources and planning tools not successful due to incompatibility	Ensure network tool, application of new technology and data requirements meet the needs of the connected customers and identified ahead of any commissioning of new ANM scheme Regular reviews across business to ensure co-ordination of solutions Engagement between relevant teams during development to ensure data integration specification and requirements deliver a single network data solution.
	Development of new technical and commercial solutions may lead to complexities introducing delays and cost to ANM roll out	SPD has already delivered ANM as part of the ARC project and introduced commercial innovation to overcome existing framework hurdles. The roll out of an integrated ANM Scheme across Dumfries & Galloway will build upon the principles and learnings. Clear equipment specification will be developed to inform the ANM procurement process with vendors being selected on the basis of their ability to demonstrate operational robustness of existing systems and their success. Smart Grid Team will be resourced with relevant expertise in design,

		deployment, operation and management of ANM and other flexible connection solutions.
Communications Failure	Communication failures associated with the equipment required to maintain operation of the ANM system and integration with customer equipment	Telecoms rollout strategy will define suite of telecom solutions required for the deployment of ANM systems across the distribution voltages as well as across different geographical areas with more less robust infrastructure. Site surveys conducted during connection application process will define communication requirements and identify most cost effective communication solution for ANM deployment.
Price Escalation	Risk of price increases compared with those included within the IRM submission	Prices are based upon recognised vendor costs and internal expertise. Expect market competition to develop with number of vendors increasing. The proposed solution is not vendor specific and a competitive procurement process will run to ensure best value is achieved.
Programme Risk	Procurement process becomes protracted, vendors cannot meet business requirements, resource constraints affect ability to meet project deliverables	Number of vendors already engaged in ANM development and flexible network solutions
Failure to Meet Future Needs	DG does not materialise in expected volumes to connect, developers unwilling to connect via ANM Changes to renewable generation support/funding	External engagement will commence Q1 2018 to communicate connection opportunities of ANM Scheme across the Dumfries & Galloway region. Establish curtailment analysis forecasting service Set out clear principles of access policy and commercial terms for developers seeking to connect Queue Management of contracted queue to ensure opportunities and network access maximised

Table 7: Project risk register

4.8 Other criteria

4.8.1 How the innovation will enhance competition within the market

Whilst not a licence requirement, Ofgem's IRM guidance document [6] encourages applicants "to address how the innovation will enhance competition within the market", where 'market' means the potential market for the innovation. This section addresses that point.

We consider three factors of this project will enhance competition within the market:

1. This project is highly replicable in GB
2. The scale of this project is a significant boost for the innovation market
3. Key parts of the project will be competitively tendered.

These are discussed below.

Replicability. This project is managing an increasingly common issue: constraints on the transmission network due to changing generation patterns. This ANM project covers 11 GSPs; there are over 400 GSPs in GB. This project would also be replicable on constrained English and Welsh 132kV networks. Given these points, there is significant scope for the need for this solution to be replicated. Doing projects with innovative solutions that can be replicated will boost the market for innovative products.

Scale. The scale of the project we are proposing is significant. It sends a strong signal that innovative solutions can be done at a much greater scale than has been done to-date, and that industry has confidence in these solutions. This also encourages other industry parties to consider projects of this scale. This increased confidence by customers and suppliers of innovative products will help build the market for them. Given this, a project of the scale we propose now would be a significant boost to the ANM market.

Competitive tendering. By going out to the market for this solution we are sending a clear signal to the innovation market that there is a real need for their products. This is turn means these companies increase their investment and presence in the GB market, which means a greater supply and availability of innovative solution. This process strengthens the innovation market.

There are two measures by which we would measure the success of this project in building the market:

1. We would look for at least two companies to respond to our tender for this project.
2. We would look for at least three more projects of this scale by the end of RIIO-ED1, with at least two of them done by another network licensee.

These success criteria are very much dependent upon the market appetite of vendors and the ambition of other DNOs to roll out ANM on a similar scale.

4.8.2 QMEC

In February 2015 Ofgem published its QMEC consultation which sought views on how arrangements for getting connected to the electricity distribution network work in practice and importantly, how they might be improved. The consultation recognised that capacity to accommodate new connections was often scarce and resulted in customers having to wait significant time periods and/or face the requirement to pay upfront for network reinforcement which in itself can affect whether or not projects progress. Ofgem asked respondents for their views on opportunities for DNOs to:

- Reduce the need for reinforcement via network management
- Reduce the need for reinforcement by managing connection offers

The output from this project, coupled with our industry leading Queue Management Policy, will enable SPEN to provide an enduring network-wide response to key QMEC action areas and deliverables, including:

- Optimum use of available capacity through wider system efficiency
- Network-wide access to flexible connection offers

- Reduced connection costs
- Reduced network reinforcement
- Improved access to constraint information
- Improved forecasting and planning service
- Greater release of unused network capacity

Our proposed project will be a significant step forward in demonstrating the extent by which capacity can be unlocked to accommodate new connections.

4.8.3 IRM funding request meets the materiality threshold

Licence condition CRC 3D.9 states that a licensee can only make an IRM funding request if it constitutes a 'material amount'. The material amount for each licensee is set out in Appendix 1 of licence condition CRC 3D. For SPD, this means that the IRM funding request must be at least £6.47m in 2012/13 prices. The IRM funding request we are making in this submission is for £9.1m (in 2012/13 prices) so we have met this requirement.

4.8.4 IRM funding request is not for money already spent

Licence condition CRC 3D.10(b) states that a licensee can only make an IRM funding request for costs that have not yet been incurred. We confirm that none of our IRM funding request is for costs that have already been incurred.

4.9 Summary

Bringing forward the proposed roll-out from the end of RIIO-ED2 would have benefits of £39.2m, compared to an IRM funding request of £9.1m (both 2012/13 prices). There would be significant carbon and financial benefits to electricity consumers, and the proposed roll-out directly supports the government's Carbon Plan and the UK's legally binding carbon targets.

In addition, there are a number of strong qualitative benefits: the proposed roll-out directly supports Ofgem and government policy on moving to a smarter more flexible system and supports Ofgem's ongoing QMEC work. The proposed roll-out will remove the barrier to community DG projects in Dumfries and Galloway. Longer term, the roll-out will help build capability on DNO-SO holistic system planning, which is essential for meeting future system challenges, and enhance competition in the market place. The project is highly replicable within GB.

Whilst there are significant benefits to consumers of bringing forward the roll out, there are no benefits to SPD and no funding has been included for this in SPD's RIIO-ED1 settlement.

In summary, there are significant carbon, financial and policy benefits from the proposed roll-out. These significantly exceed the cost of the project and these all benefit electricity consumers.

5 Regulatory Issues

During the development of this IRM submission we have not identified the need for any derogation from SPD's licence conditions, the licence conditions of other parties, or industry codes. If we are granted funding and then during the roll-out the need for derogation becomes apparent, we will engage with the Authority in a timely manner.

5.1 Customer engagement

Stakeholder engagement is firmly embedded within our business. From top to bottom, at every level, engaging with our stakeholders has become part of our DNA.

We know the importance and benefits of ensuring our activities match stakeholder feedback. We ensure that stakeholders opinions are reflected in our continual strive for improvement. SPD has a strong connections focused customer engagement programme which includes workshops and stakeholder panel sessions allowing stakeholders to engage with us at a strategic level or within the specific areas that are most important to them.

We also see the value in working collaboratively with our transmission business on common stakeholder issues, for example Queue Management, Statement of Works and supporting the SPT Dumfries and Galloway Stakeholder Events which are held bi-annually.

During the December 2016 SPT Dumfries & Galloway Stakeholder event, SPD launched their plans to design and develop a Smart Grid Zone for Dumfries & Galloway in direct response to outcome of the NGET CBA.

We have continued to engage with our transmission business for guidance and support in the development of our Smart Grid Zone plans.

Targeted local stakeholder events with our Dumfries and Galloway customers will be key to ensure that our customers have full visibility of the connection opportunities we can provide under the ANM Scheme.

6 Appendices

This document contains the following appendices:

- Appendix A – References and Footnotes
- Appendix B – Abbreviations
- Appendix C – Meeting CRC 3D.13
- Appendix D – Carbon and financial modelling
- Appendix E – Proposed Relevant Adjustments
- Appendix F – Project plan

6.1 Appendix A – References and footnotes

References:

1. Source of diagram: NGET's 'Electricity Ten Year Statement 2016', published November 2016.
2. National Grid's 'Dumfries and Galloway Strategic Wider Works; Need Case: Cost Benefit Assessment', dated July 2016.
3. Special licence condition CRD 3D of SP Distribution PLC's 'Conformed Distribution Licence', version 10, dated January 2017.
4. Ofgem's 'Unlocking the capacity of the electricity networks', published 14 February 2017.
5. Ofgem and the Department for Business, Energy & Industrial Strategy's 'A Smart, Flexible Energy System; A call for evidence', published November 2016.
6. Ofgem's 'Electricity Distribution Innovation Roll-out Mechanism submission guidance', published 17 February 2016.
7. Ofgem's 'Guide to the RIIO-ED1 electricity distribution price control', published 18 January 2017.
8. SP Energy Network's 'ARC Closedown Report', published 31 March 2017.
9. SP Energy Network's 'SPEN DSO Vision', published 21 October 2017.
10. Department of Energy and Climate Change's 'Carbon Plan', published December 2011.
11. Email from Dinker Bhardwaj, Ofgem, to Julian Wayne, Culan Strategy Ltd, dated 4 May 2017.
12. http://www.annabaglish-windfarm.co.uk/local-benefits/
13. http://www.renewableuk.com/resource/resmgr/publications/reports/onshore_economic_benefits_re.pdf
14. http://www.nrel.gov/analysis/jedi/
15. http://www.southernwind.org/uploads/1/9/8/9/19892499/louisiana_land_based_wind.pdf
16. https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract

Footnotes:

A. G59 DG means DG that is greater than 16Amps/phase. This equates to 3.7kW single phase and 11kW three phase.

B. By 'active participation' we mean that the generator submits bids and offers at appropriate prices and can implement instructions sent to them by the SO. This is as opposed to generators who have to participate because of their size, but set bid offer prices at such a high value to effectively prevent ever being called upon by the SO.
C. This is mainly because bid offer prices from renewable generators were always higher than coal and gas providers. This is due to their zero-marginal cost to produce energy, the fact that unused wind couldn't simply be saved for use later (like coal or gas), and the value of the FIT/ROC. Given this, even though they had the technical capability to perform a range balancing services, they were very rarely called upon by the SO.
D. There are still other barriers to this, such as ancillary service contract lengths.

6.2 Appendix B – Abbreviations

ANM – active network management

ARC – Accelerating Renewable Connections; a LCN Fund project

BM – balancing mechanism; the platform where the SO can procure constraint management and balancing services

CBA – cost benefit analysis

DG – distributed generation

ENA – Energy Networks Association

FES – Future Energy Scenarios

GHG – greenhouse gas

GSP – Grid Supply Point; a substation that connects the distribution network to the transmission network

KTR – Kendoon Tongland reinforcement; the transmission reinforcement scheme in the Dumfries and Galloway area that will be complete 2023

LCN – Low Carbon Network (Fund)

LIFO – last in first off; a method to determine the constraint merit order for DG

LMS – load management scheme; the scheme currently in place to protect against thermal constraints on the transmission system during intact conditions.

NGET – National Grid Electricity Transmission; means its SO function where referred to in this report

QMEC – Quicker More Efficient Connections; an Ofgem connections policy

RAA – restricted available access; the policy by which DG is connected in Dumfries and Galloway

RO – Renewable Obligation

ROC – Renewable Obligation Certificate

SIO – system imbalance price

SO – the system operator

SPD – SP Distribution; the distribution network owner for south Scotland, including the Dumfries and Galloway region

SPT – SP Transmission; the transmission network owner for south Scotland, including the Dumfries and Galloway region

SWW – strategic wider works

TRL – technology readiness level

UoS – use of system (charges)

6.3 Appendix C – Compliance with CRC 3D.13

Licence condition CRC 3D.13 lists the requirements that any IRM submission must meet. For convenience, Table 8 sets out these requirements and identifies where in this IRM submission these are evidenced. Where the licence requirement says "Notice", it means "IRM submission"; where the licence requirement says "this condition", it means licence condition CRC 3D.

Licence Requirement CRC 3D.13	Location in this IRM submission
(a) state any statutory obligations or requirements of this licence to which the Notice relates	Throughout this submission – for every occasion where we are providing evidence directly in response to a CRC 3D licence requirement, we reference the licence condition.
(b) describe the Proven Innovation that the licensee proposes to Roll-out	Section 2.3
(c) propose the amount of the Relevant Adjustment and set out, by reference to the Innovation Roll-out Costs, the basis on which the licensee has calculated it	Section 2.4
(d) demonstrate that the costs to be recovered through the Relevant Adjustment will be a material amount for the purposes of paragraph 3D.9 of this condition	Section 4.8.3
(e) demonstrate how each of the criteria set out in Part B of this condition will be fulfilled by the Roll-out using additional funding sought	Section 4
(f) propose relevant outputs or other end products against which the Roll-out will be assessed	Section 4.3.3 and section 4.8.1
(g) set out the revisions to IRM values that the licensee considers should be made to implement the Relevant Adjustment	Appendix E
(h) state the date from which it is proposed that the Relevant Adjustment would have effect ("the adjustment date) and the Regulatory Years to which the Relevant Adjustment would apply	Appendix E

Table 8: compliance of this IRM submission with licence condition CRC 3D.13

6.4 Appendix D – Carbon and financial modelling

This section sets out our carbon and financial modelling process, and the key assumptions used for the year up to 2030/31. We have not modelled benefits beyond 2030/31 as we assume that this is the date by which AMN would be in place in Dumfries and Galloway under the counterfactual scenario. This means that there are no differences between the two scenarios after 2030/31.

A note on terminology: the 'counterfactual' means the existing 'LMS', we use the terms interchangeably; the 'IRM scenario' means the proposed 'ANM scheme', we use the terms interchangeably. All years are expressed in regulatory years, i.e. 2018/19 means the year from 1 April 2018 to 31 March 2019.

6.4.1 The counterfactual scenario

[redacted] For the counterfactual scenario, we assumed that:

- This existing [redacted] DG on the LMS would remain on the LMS – this is a reasonable assumption as there is no other tool in place to manage the transmission constraint.
- We assume that this [redacted] DG will realise the benefits of the additional network capacity by KTR as soon as it is complete. We assume KTR completes at the end of 2023/24.
- No new DG would connect before the completion of KTR. This is a reasonable assumption given the barrier to new DG that the LMS presents. This is supported by the fact that none of the 200MW of contracted DG is pushing SPD to progress their connection.
- Once KTR is complete at the end of 2023/24, we assume that new DG will connect immediately and up to the same volume as what would already be connected under the ANM scenario, and remain at this level until the end of RIIO-E2. This is a simplistic assumption, but we have assumed the same ramp rate for the connection of new DG to the ANM scheme in the ANM scenario – by using the same ramp rates in the two scenarios we do not add bias towards one of the scenarios.
- From 2023/24 onwards we assumed that DG would continue to connect at the same rate and volume as under the ANM scenario, until the network becomes constrained again.
- At the end of 2030/31 an ANM scheme would be rolled out across Dumfries and Galloway.

Using realistic wind output profiles and a model of the network, the MWh output and MWh constrained from these [redacted] existing DG projects was modelled. The results until 2023/24 are shown in Table 9. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24
MW connected under LMS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Total MWh generated	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total MWh constrained	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 9: Counterfactual pre-KTR generation and constraint values

Post KTR completion at the end of 2023/24, we assumed the same level of DG would connect as what would already be connected pre-KTR under the ANM scenario, i.e. immediately post KTR there would be no difference in connected MW between the counterfactual and ANM scenarios. From 2023/24 onwards we assumed that DG would continue to connect at the same rate and volume as under the ANM scenario, until the network becomes constrained again.

These values are the baseline against which we assessed the proposed ANM scheme.

6.4.2 The IRM scenario

For the IRM scenario, we assumed that:

- The ANM scheme will be commissioned and ready for connections at the end of 2018/19. This is a reasonable assumption as the ANM is scheduled to be completed halfway through 2018/19.
- The existing [redacted] DG currently on the LMS would transition to the ANM when it is complete at the end of 2018/19 – this is a reasonable assumption as they incentivised to transfer to the ANM as they will realise increased revenue on the ANM scheme due to lower constraints.
- Once the ANM is complete at the end of 2018/19, we assume that new DG will connect immediately and remain at this level until the end of RIIO-E2. This is a simplistic assumption, but we have assumed the same ramp rate for the connection of new DG post-KTR in the LMS scenario – by using the same ramp rates in the two scenarios we do not add bias towards one of the scenarios.
- We assumed that new DG would connect to the ANM until the point where any new DG was constrained more than 5%. This was to reflect that any DG projects with more than 5% constraints were unlikely to be economically viable due to reduced revenue. This was a prudent step to ensure that the benefits weren't being overstated by unrealistically overloading the ANM scheme.
- Beyond the DG that connects in 2019/20, we assumed that no further DG connected until the beginning of 2023/24 as this would bring the network to full capacity. KTR would have completed in 2023/24 and created additional network capacity. Given that all NGET FES scenarios show increasing DG in the 2020-30 period and Dumfries and Galloway has good wind resource, it's a reasonable assumption that DG will connect to the network in this period. We assumed broadly the same project economics for DG as before KTR, so the network fills to the same DG constraint limit (5%) as pre-KTR.
- All the DG that would connect under the ANM is zero carbon (i.e. renewable generation). This is a reasonable assumption given that all the 200MW of consented projects are renewable, and that smaller-scale community schemes are typically renewable.

Using realistic wind output profiles and a model of the network, the MWh output and MWh constrained from the [redacted] existing DG projects and the contracted DG was modelled. We then discounted any DG that would have been constrained more than 5%. The pre-KTR results of this analysis, showing how many MW would connect and result MWh of generation and constraint, are in Table 10. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24
MW connected under ANM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total MWh generated	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total MWh constrained	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 10: IRM scenario pre-KTR generation and constraint values

Post KTR completion at the end of 2023/24, we assume that DG will continue to connect to the network at the same rate and volume under both scenarios. The difference would arise when sufficient new DG have been connected to trigger constraints.

These values were then compared against the counterfactual values to identify the MWh benefit of the ANM scheme (see section 6.4.3 below).

6.4.3 Comparison of IRM and the counterfactual

As benefits from the ANM scenario fundamentally arise from less MWh constrained, and more MWh generated by DG, the difference in these values between the counterfactual and the IRM scenario was calculated – this is simply the difference between the values in Table 9 and those in Table 10. These are shown in Table 11. A positive value indicates more MWh generated/constrained under the ANM scheme; a negative value indicates more MWh generated/constrained under the LMS. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024-27	2027/28	2028/29	2029/30	2030/31
Δ MW connected	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Δ Total MWh generated	174,004	174,004	174,004	174,004	174,004	0	10,161	174,004	174,004	174,004
Δ Total MWh constrained	-5,873	-5,873	-5,873	-5,873	-5,873	0	-10,161	-5,873	-5,873	-5,873

Table 11: the difference between the IRM and counterfactual

Table 11 shows that from 2019/20 to 2023/24 more DG is connected to the system under ANM than under the LMS. This results in more MWh generated (due to more DG being connected) and lower constraints (due to the increased sophistication of the ANM scheme constraint management).

From 2024/25 the difference between the two schemes reduces to zero. This reflects that the KTR project is completed at the end of 2023/24, and results in sufficient

increased transmission capacity that new DG connects under the LMS scenario such that there is an equal volume of DG under the two scenarios. With the same volume of DG, and no constraints due to the increased network capacity, there is no difference between the ANM and LMS schemes.

From 2024/25 onwards, DG continues to connect to the system at the same rate and volume under both scenarios (so the ΔMW values for these years are 0). All NGET Future Energy Scenarios (FES) scenarios show increasing DG in the 2020-30 period and Dumfries and Galloway has good wind resource, it's a reasonable assumption that DG will connect to the network in this period.

In 2027/28 the level of new DG in both scenarios has increased such that transmission constraints are triggered for the LMS scenario but not the ANM scenario. Given this constrain, we assume that no new DG connects under the LMS scenario from this point forwards (for the same reasons why we assume that no new DG will connect under the LMS scenario from now until 2023).

In 2028/29 new DG only connects under the ANM scenario (as the LMS scenario has become constrained in 2027/28). We assume broadly the same project economics for DG as before KTR, so the network fills to the same volume of DG. All NGET Future Energy Scenarios (FES) scenarios show increasing DG in the 2020-30 period and Dumfries and Galloway has good wind resource, it's a reasonable assumption that DG will connect to the network in this period.

We have not modelled benefits beyond 2030/31 as we assume that this is the date by which AMN would be in place in Dumfries and Galloway under the counterfactual scenario.

The values in Table 11 represent the difference between the LMS and ANM schemes, and are the values from which the benefits are calculated.

6.4.4 Carbon benefit calculations

As we assumed that all the new DG that would connect under both scenarios would be renewable, we could calculate the carbon benefit by using the MWh values from Table 11 and the 'electricity GHG conversion factors' (tonnes CO_2/MWh) in the RIIO-ED1 CBA Tool. These calculations are set out in Table 12. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024-27	2027/28	2028/29	2029/30	2030/31
Δ Total MWh generated	174,004	174,004	174,004	174,004	174,004	0	10,161	174,004	174,004	174,004
GHG conversion factor, tonnes CO_2/MWh	0.445	0.430	0.416	0.401	0.387	~	0.329	0.314	0.300	0.285
Resultant CO_2 benefit, tonnes	77,408	74,886	72,364	69,841	67,319	0	3,342	54,708	52,186	49,663

Table 12: ANM scheme tonnes CO_2 benefit

From Table 12 it can be shown that the proposed ANM scheme results in a total carbon benefit of 521,717 tonnes CO2 in the period to end of 2030/31.

6.4.5 Financial value of carbon saving

The financial value of the saved carbon can be calculated by using tonnes saved CO_2 from Table 12 and the forecast 'traded carbon price' (£/tonne) values in the RIIO-ED1 CBA Tool. This calculation is shown in Table 13. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024-27	2027/28	2028/29	2029/30	2030/31
Resultant CO_2 benefit, tonnes	77,408	74,886	72,364	69,841	67,319	0	3,342	54,708	52,186	49,663
Traded carbon price, £/tonne	9.24	16.49	23.74	30.98	38.23	~	67.23	74.48	81.73	87.51
Resultant benefit, £m	0.72	1.23	1.72	2.16	2.57	0	0.22	4.07	4.27	4.35

Table 13: ANM scheme carbon value benefit

From Table 13 it can be shown that the proposed ANM scheme results in a carbon benefit of £21.3m in the period to end of 2030/31.

6.4.6 Financial value of imbalance

Under both the LMS and ANM schemes, DG is constrained off the system with no advanced warning. This creates imbalance in the system. This imbalance has a cost, either because NGET has to bring on additional generation to replace what's lost in order to maintain system frequency or because suppliers are hit with imbalance charges. Either way, these costs are ultimately recovered from consumers, either via balancing services use of system (BSUoS) charges that are imposed on suppliers or the direct cost to suppliers of imbalance charges. In short, less MWh constrained is a consumer benefit as it means lower costs recovered from consumers.

To calculate this benefit, we need to know the cost of the imbalance is. The potential loss of generation from the LMS – [redacted] – is a relatively small volume compared to overall system load so will have a negligible impact on system frequency. Given this, it felt unlikely that NGET would be using a higher cost ancillary service to cover the loss of this DG. We therefore calculated the loss of this generation using the SIP from the BM.

The SIP is a good reflection of the cost of imbalance. It varies every settlement period and has a high degree of volatility. Given this, we used average values from 2016. Two average values were available: one for when the overall system is long, and one for when the overall system is short. We took these two average values for 2016, and gave 75% weight to the long value and 25% weighting to the short value. This reflects the proportion of 2016 that the system was long versus short. This gave us an average SIP value for 2016 of £41.01/MWh.

Using this value and the value from constrained MWh values from Table 11 we could calculate the total value of reduced imbalance costs between the ANM and LMS

scenarios. This calculation is shown in Table 14. Negative MWh constrained means that there is a lower volume of constraints under ANM than the LMS. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024-27	2027/28	2028/29	2029/30	2030/31
Δ Total MWh constrained	-5,873	-5,873	-5,873	-5,873	-5,873	0	-10,161	-5,873	-5,873	-5,873
SIB, £/MWh	-38.38	-38.38	-38.38	-38.38	-38.38	0	-38.38	-38.38	-38.38	-38.38
Resultant benefit, £m	0.225	0.225	0.225	0.225	0.225	0	0.390	0.225	0.225	0.225

Table 14: ANM scheme imbalance savings

From Table 14 it can be shown that the proposed ANM scheme results in imbalance savings of £2.2m in the period to end of 2030/31.

6.4.7 Value to existing DG of reduced constraints

[redacted] We assume that these will transition onto the ANM scheme when it is complete. Once they are on the ANM scheme, they will be subject to fewer constraints. This means there is value to these parties from the ANM scheme. As they are classed as 'electricity consumers' for the purpose of licence condition CRC 3D, we calculated these benefits.

The financial benefit to these parties can be calculated from how much extra MWh they generate under the ANM compared to the LMS due to fewer constraints, and the revenue they receive from each MWh of generation. Given that these are zero marginal cost plant (i.e. the cost to produce an extra MWh is £0 as they don't have any fuel costs) we can assume that all increased revenue is benefit. These are all RO accredited sites, so we assume that a MWh is worth £81 (2012/13 price, roughly split between the value of the ROC and the value of the electricity). From these, we can calculate the financial benefit. This is shown in Table 15. The values in each column are for that year, i.e. they are not cumulative.

	2019/20	2020/21	2021/22	2022/23	2023/24	2024-27	2027/28	2028/29	2029/30	2030/31
Additional MWh generation	[redacted]									
Value £/MWh	[redacted]									
Additional generation benefit £m	[redacted]									

Table 15: ANM scheme value to existing DG

From Table 15 it can be shown that the proposed ANM scheme results in benefits to the existing DG schemes of £7.4m in the period to end of 2030/31.

6.4.8 Local economic benefit

With rare exceptions in very remote areas, communities local to DG developments are all customers of the distribution network. The development of DG brings economic benefits to the local community. These can be classed in two ways: energy financial benefits (usually in the form of developers offering discounted electricity to local residents) and non-energy financial benefits that arise from presence of local development (for example, increased expenditure in shops and hotels, and employment of local suppliers and contractors). Energy benefits are dependent on which company is developing the DG; we have therefore not included these in our quantitative assessment. Non-energy benefits are intrinsically associated with the development of DG projects and there are a number of case studies which have quantified these based on assessment of a large number of projects. We have therefore included these in our quantitative assessment.

To form a value for the local economic benefit we assessed a number of sources [12][13][14][15]. The lowest of these values was £0.28m/turbine. [redacted] By using this lowest value we have taken a conservative approach and may have understated this benefit.

[redacted]

Under the LMS scenario, we assume the same volume of DG would connect to the network, but only at the beginning of 2024/25 once KTR is complete. Therefore under the LMS scenario this local economic benefit would still arise, but at a later date.

Therefore the benefit of the ANM over the LMS isn't the absolute value of the local economic benefit, but the time-value-of-money benefit of moving this benefit forward. This is shown in Table 16. A positive value indicates where the benefit accrues for ANM, a negative value shows where it would have accrued for LMS.

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024-27	2027/28	2028/29	2029/30	2030/31
Local economic benefit, £m	[redacted]										

Table 16: Local economic benefit of ANM versus LMS

This equates to total local economic benefit of £2.5m (in 2012/13 prices) for the ANM scenario compared to the LMS scenario.

6.4.9 Avoided expenditure

Under a business as usual scenario, ANM would be implemented late in RIIO-ED2. To ensure that this option is comparable to the baseline, these costs are treated as avoided expenditure.

An efficiency factor has been adopted to represent the fact that ANM will become cheaper as it matures. We have used an efficiency factor of 75%, i.e. at the end of RIIO-ED2 ANM will be 75% of the cost it is now. Given that the majority of costs of an ANM scheme are items that are mature (e.g. fibre optic cables), and so unlikely to

significantly decrease, we consider that this is ambitious, meaning we are likely understating this benefit. Table 17 shows these values.

	2029/30	2030/31	2031/32	2032/33	2033/34
Local economic benefit, £m	2.69	2.69	0.47	0.47	0.47

Table 17: Avoided ANM Expenditure

This equates to an avoided expenditure benefit of £6.8m (in 2012/13 prices) for the ANM scenario compared to the LMS scenario.

6.1 Appendix E – Proposed Regulatory Adjustments

Licence condition CRC 3D.13(g) requires the licensee to propose revisions to the IRM values that the licensee considers should be made to implement the Relevant Adjustment. This section fulfils that requirement.

Table 18 sets out our proposed Relevant Adjustment, i.e. our proposed revisions to the IRM values. We have based these on the approach of recovering IRM costs in the same regulatory year in which they occur. This was the approach advised to us by Ofgem [11].

	2018/19	2019/20	2020/21	2021/22	2022/23
SPD proposed revision to IRM values, £m	3.59	3.59	0.63	0.63	0.63

Table 18: SPD proposed Relevant Adjustment