

# FLEXIBLE INTERCONNECTION FOR DISTRIBUTED ENERGY RESOURCES

## Emerging Practices at Early-Adopter Utilities



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## Abstract

*Increasing grid penetrations of distributed energy resources (DER) are beginning to challenge the accommodation limits of existing distribution infrastructure in certain locations. While circuit capacity limits can be expanded, the required system upgrades often add significant costs and delay. In response, “flexible interconnection” approaches are being developed to increase distribution system utilization and allow more DER to connect and export power to the grid while lowering the cost of integration.*

*This paper describes emerging requirements and practices for flexible interconnection at a selection of early-adopter utilities. The technical and economic drivers of flexible interconnection arrangements are initially introduced, and a selection of relevant control techniques for achieving flexible interconnection are identified. The key steps of the interconnection process itself are subsequently discussed. Then, the technical and economic aspects of six ongoing demonstration projects in the U.K., France, the U.S. and Canada are presented, covering a variety of DER types, control techniques, and network constraints. Finally, key learnings and emerging requirements supporting the introduction of flexible interconnection products are summarized based on the utility demonstration projects reviewed.*

*This paper is part of an ongoing EPRI white paper series exploring related DER integration topics around flexible interconnection (3002014475), active power management (3002013325), DER management systems (3002013049), and the economic and regulatory aspects of PV curtailment (3002010289).*

## Real-Power Management for DER: Transitioning from Firm to Flexible Interconnection Approaches

Distribution circuits have time-varying technical constraints for voltage regulation, thermal loading, protection, and power quality that can be a significant barrier to achieving higher DER penetrations. These technical constraints are functions of the underlying load, generation, temperature, control settings, circuit configuration, and other system parameters. Any DER importing or exporting power in excess of limits that would violate these constraints has potential to degrade system operating conditions. For this reason, conventional interconnection practices either limit DER nameplate capacity to ensure that existing technical constraints are enforced at all times, or require infrastructure upgrades to accommodate more DER that can be costly and/or significantly increase connection times.



*Real power management*, also referred to as *active power management*, is set of control approaches that can help increase distribution system utilization, and eventually support higher DER penetrations at lower integration cost. By limiting DER imports and/or exports at key times where distribution system constraints are binding, real-power management in effect supports more average energy transfer, and larger connected DER nameplate capacity in more locations by enabling DER to become a manageable asset whose output can be adjusted based on grid conditions.

From a control standpoint, *autonomous inverter functions* following a configurable response profile (e.g. volt-watt, frequency-watt) as defined in IEEE Standard 1547 or in the European Network Code Requirements for Generators (RfG), can help defer costly system upgrades at higher DER penetration levels. *Managed control* is another emerging control approach for real-power management that relies on communications infrastructure and control signals sent by a distributed energy resource management system (DERMS)-like utility control platform requesting DER units to set or adjust their imports or exports to specific real-power levels, based on grid conditions.

As described in this paper, flexible interconnection arrangements aim to leverage managed control to defer system upgrades and/or increase distribution system utilization. While autonomous functions are increasingly becoming a standard requirement in conventional “firm” interconnection agreements, managed control requires specific

contractual arrangements by which DER owners allow the utility or a third-party to act as DER management entity. This evolution is at the core of emerging “flexible” interconnection agreements.

## Control Techniques to Achieve Flexible Interconnection

Several managed control methods are emerging from recent and ongoing utility demonstrations that are suitable for supporting flexible interconnection arrangements. As shown in Table 1, and further elaborated below, these methods are organized into three categories, each reflecting increasing levels of complexity. Several utilities have started to integrate the technical and commercial requirements associated with each of these control techniques in their reference documentation, for example see [4] and [5].

### Category 1: Control Techniques Addressing Fixed Constraints

This first category mainly consists of timed capacity connections. Under this approach, DER are required to manage their import and/or export levels following a time-differentiated operating schedule defined as part of their flexible interconnection agreement. The schedule is defined based on typical local network conditions. Constraints can be defined hourly or sub-hourly, and seasonal variations can be introduced. Table 2 presents an illustrative example.

Table 1 – Emerging control techniques demonstrated at early-adopter utilities to support flexible interconnection arrangements.

Category	Level of Complexity	Control Technique	DER Managed	Number and Location of Monitoring Points	Approach
1	Fixed constraints	Timed capacity connection	Single or co-located DER	Single monitoring location at DER site	Apparent power at point of connection managed based on pre-determined time-differentiated operating schedule.
2	Simple, localized constraints	Export limiting devices	Single or co-located DER	Single monitoring location at DER site	Power exports at point of connection managed in real-time to enforce a maximum export capacity by curtailing generation and/or managing local demand.
		Local management schemes	Single or co-located DER	Single monitoring location at DER site	Power exports managed in real-time based on parameters monitored at the point of connection and indicative of potential network issues.
			Single or co-located DER	Single distant monitoring location	Power exports managed in real-time based on parameters monitored at a distant location and indicative of abnormal system conditions.
3	Multiple constraints, potentially nested and/or spanning a wider network area	Active power management (centralized or decentralized)	Multiple DER geographically dispersed	Multiple distant monitoring locations	Export capacity dynamically allocated for multiple DER based on real-time monitoring of DER outputs and grid conditions, following agreed-upon dispatch rules.



Table 2 – Illustrative example of a pre-determined time-differentiated operating schedule.

Period	11am to 4pm	4pm to 11am
November to February	No constraint	No constraint
March to May	70% of full DER output	No constraint
June to October	50% of full DER output	No constraint

The main advantage of this first approach is simplicity. No real-time communications are expected between the utility and the DER customers as the time-differentiated operating constraints are not meant to be updated dynamically. It also offers relative operating visibility to the customer. Early-adopter utilities have typically considered this approach for smaller customers (<500kVA) connecting at lower voltages.

### Category 2: Control Techniques Addressing Localized Constraints

Control techniques in this second category aim to manage a single DER, or a set of co-located DERs, to address *localized* constraints based on real-time measurements. The specific constraints triggering curtailment measures (possibly down to temporary no-export) are identified as part of the flexible interconnection agreement. Constraint examples include thermal operating limits constraining the operation of a distribution line or a substation transformer. Several control techniques in this category – including export limiting devices, local management schemes, and remote inter-trip arrangements – are being integrated into standard practices at early-adopter utilities to address an array of scenarios.

#### Export Limiting Devices

This approach is particularly relevant for customers installing DER generation to primarily offset their energy imports, in circumstances where increasing their export capacity would require costly network reinforcements. When exports reach a pre-defined threshold, the limiting device curtails the DER output and/or manages local loads within a given timeframe (typically a few seconds) to enforce a maximum export capacity. Utilities require all communications to be fail-safe (specifying a fallback value) and/or require a reverse power relay to automatically disconnect the DER if any of the control system elements loses communications and/or power. A separate reverse power relay may be required – especially for larger DER sizes – to trip the generation unit should the dynamic export limits be exceeded at any time.

#### Local Management Schemes

This approach aims to address local network issues that can be detected using low-cost monitoring equipment located either *at the customer site*, or possibly *at the point of connection*. Typical parameters monitored include voltage and power flows. These issues, explicitly identified in the flexible interconnection agreement along with all relevant action thresholds, can relate to voltage or thermal constraints, transformer reverse power constraints, or occurrence of a N-1 contingency situation. When action thresholds are crossed, export capacity is reduced (possibly down to zero). This technique is appropriate to address simple network constraints and can manage a single generator, or a group of co-located generators.

#### Remote Inter-Trip Schemes

This approach temporarily reduces the export limit of a DER or a group of co-located DERs (potentially down to zero) when a single network limit, monitored in real-time at a location *distant* from the DER site, is infringed. An example of this might be the reverse power flow at a distant substation upstream of the DER site being managed. The full export capacity is released when normal operating conditions return.

### Category 3: Control Techniques Addressing Multiple or Distant Constraints

Control techniques under this category, commonly referred to in Europe as *Active Network Management (ANM)*, continually allocate power export capacity to multiple, geographically-dispersed DER assets based on the DER generation and grid conditions monitored in real-time at multiple distant locations. The controlled area can be circumscribed to a specific sub-section of the distribution system, a specific substation area, or cover a portion of the distribution system spanning multiple substations.

Curtailment signals are issued following agreed-upon principles specified in the flexible interconnection agreement. Dispatch methods considered in utility demonstrations to date include:

- *Last In, First Out (LIFO)*, where the last DER interconnected is the first to get curtailed.
- *LIFO combined with sensitivity factors*, representing the relative effectiveness of each DER at addressing a specific network constraint. This approach is particularly relevant under abnormal conditions to ensure that the DER getting curtailed will have an actual impact on the constraint being addressed.



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- **Power Injection Maximization**, where a group of DER is managed to maximize the overall power exported to the distribution grid across the group.
- **Most Commercially Efficient Dispatch**, taking into account generator constraint payments where these exist.

ANM deployments can either follow a *centralized* or *decentralized* approach:

- In centralized implementations, all ANM calculations are performed on virtual machines hosted on servers located at a distribution control center. Existing backbone communication networks are leveraged to collect measurements and send dispatch commands to DER connected under flexible agreements. This approach provides system-wide visibility to manage large distribution areas, but potentially introduces a single point of failure.

- In decentralized implementations, ANM calculations are performed on computers located at substations. This approach can be used to manage a smaller distribution area. While multiple smaller areas managed in a decentralized fashion may reduce the risk of system-wide catastrophic failure, the level of visibility provided may be inferior to the levels archived by a centralized implementation.

### Securing a Flexible Interconnection Agreement: A Multi-Step Process

Utility flexible interconnection offers each have their own unique specifications, but similarities also exist among them. Three typical steps can be taken to develop a fully executed flexible interconnection agreement (Figure 1).

## Application of Active Power Management to Load Balancing in Remote Grids

Other applications of active power management exist beyond those employed for flexible interconnection. One example is the management of isolated or insular grids, where active power control of DER can help reach higher DER penetrations while supporting real-time balancing of energy production and demand.

In Corsica and the French Caribbean islands, any interconnected DER larger than 3kVA can be remotely disconnected when the active power injected by PV and wind assets exceeds 30% of the total active power injected to the grid. In addition, during abnormal system conditions, DER assets can be disconnected at any time. While the application is different, the technical approach is similar to the one followed by French DSO ENedis in Metropolitan France to support implementation of flexible interconnection agreements: customers applying for interconnection are provided an estimate of the duration (number of hours per year) and anticipated evolution of active power curtailment; curtailment is executed following a LIFO approach, where the last customer interconnected is the first disconnected; and the same standardized “DEIE” local controller (Figure 3) reports power exports to a central controller and receives curtailment signals. Distributed generators are not subject to disconnection under the 30% rule if they can achieve the same results when paired with an energy storage system.

In Australia, Horizon Power operates 38 isolated microgrids spread throughout Western Australia, some of which are experiencing PV penetrations of up to 20% of installed generating capacity. Horizon Power is witnessing dramatic effects from passing clouds where renewable energy penetration is high and the limited geographic footprint of the microgrid reduces spatial smoothing of PV. Without active management of PV, some of Horizon Power’s microgrids are unable to accommodate any additional solar generation, even with blanket feed-in restriction. Consequently, PV systems larger than 50 kW must be able to receive and act upon signals to ramp up or down as part of the interconnection requirements.

Similar to some of the flexible interconnection demonstrations described in this paper, Horizon Power’s active power management scheme connects a central programmable logic controller (PLC) at the control center to PV assets via a corporate communication network, and a 100% private 3G cellular network for the last-mile communication link. Curtailment signals are interpreted directly by PV inverters. This control scheme is different than some of the flexible interconnection demonstrations described in this paper such as Enedis demonstration using a “DEIE” local controller to interface between the generator and central controller with the capability to open a circuit breaker if the generation unit becomes unresponsive to curtailment signals.

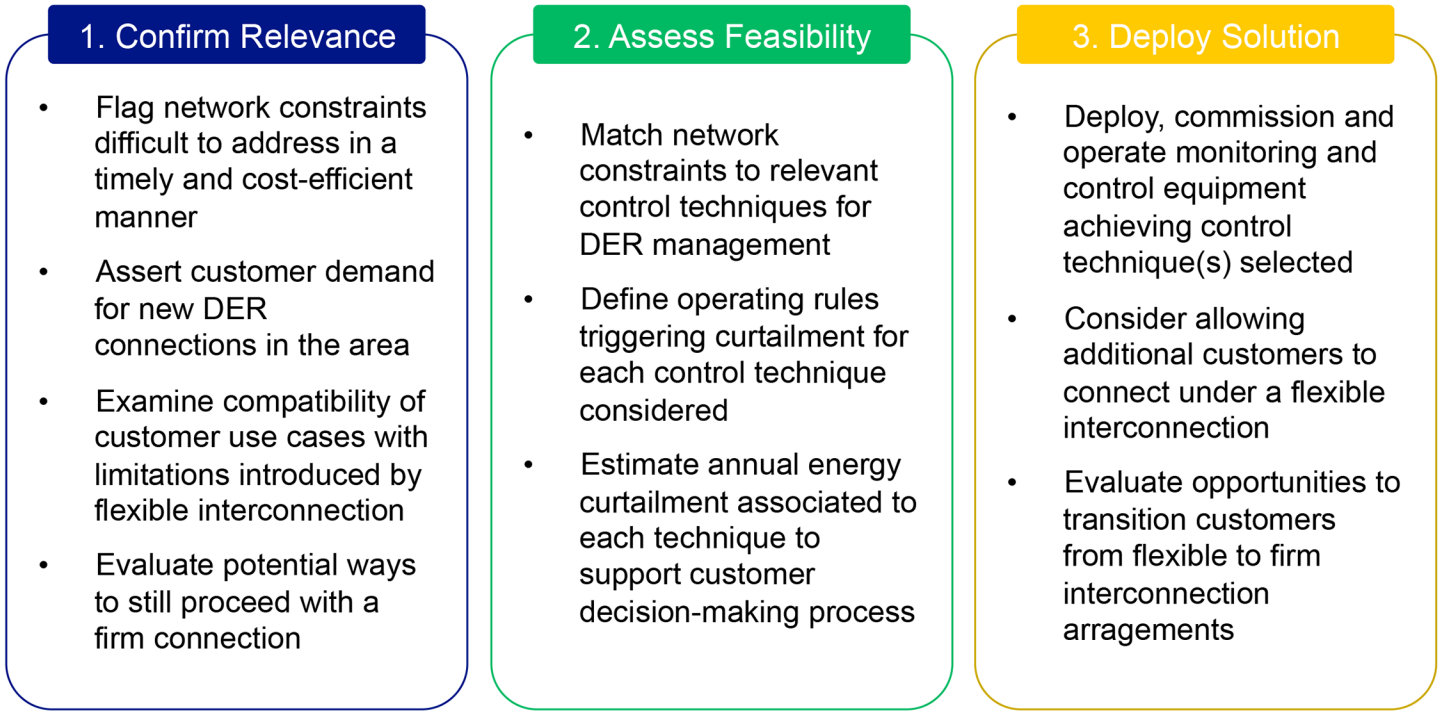


Figure 1 – Typical multi-step flexible interconnection process

### Step 1: Is Flexible Interconnection Relevant?

Flexible interconnection can be beneficial when the conventional “firm” interconnection approach cannot be executed cost-efficiently and/or involves long connection delays to complete network reinforcements. Depending on the utility, the customer must explicitly express interest in a flexible arrangement; otherwise, the utility can offer this option for consideration as an alternative if significant connection costs and/or delays are anticipated. Even then, alternative strategies relying on traditional, “firm” connection agreements can be explored, such as:

- Divide and conquer:** For larger DER sites, when a unique point of connection cannot accommodate the anticipated export capacity under a firm agreement, the site may be divided into sub-sites, each exporting power to a different existing feeder under a firm agreement. French Distribution System Operator (DSO) Enedis is incorporating this practice into their business-as-usual processes.

- Form a multi-customer consortium:** While network reinforcements might not be cost-effective for a single DER, multiple customers in the same area may form a consortium to share the network reinforcement costs and make the firm interconnection option cost-beneficial.<sup>1</sup> As part of their interconnection practices, U.K. Distribution Network Operator (DNO) Scottish and Southern Electricity Networks (SSEN) maintain a consortia register to help customers identify others interested in connecting in the same area.
- Trade capacity with an existing customer:** a new DER may be able to connect in a constrained area by sharing export capacity with an existing customer routinely under-utilizing their export capacity already approved under an existing firm interconnection agreement. Another option can be to partner with a customer who is able to increase their baseload when both customers are located downstream of the limiting network constraint, for example an industrial customer willing to electrify part of their fabrication processes.

<sup>1</sup> Other options for sharing upgrade costs are discussed in *Exploring DER Interconnection Cost Allocation Approaches and Tradeoffs*, EPRI, Palo Alto, CA: 2018, 3002012961.



## Step 2: Feasibility Assessment

When flexible interconnection is identified as a potentially beneficial option, the network constraints preventing the timely and/or cost-efficient execution of a firm agreement must be carefully studied to select control techniques that can effectively address the constraints. For each relevant control technique identified, a forecast of the electricity that the DER can expect to export must be developed to help the customer evaluate the financial viability of the potential arrangement. Forecasts are usually developed on an annual basis using historical data (including typical network configuration in normal conditions) and any expected evolutions impacting the export capability at the location considered (e.g. load growth or deflection, expected DER growth, network reinforcements already under construction, etc.) The proposed dispatch scheme (i.e. LIFO or other) is also a key input influencing the outcome of this analysis. Another factor that must be considered as part of the decision process is determining whether the customer is mandated to financially contribute towards future reinforcements to eventually convert their flexible interconnection agreement into a firm agreement.

## Step 3: Solution Deployment

Once fully deployed, the control technique selected to achieve flexible interconnection manages the DER export limits in real-time. Additional customers may request connection under a flexible interconnection in the same area if deemed cost-beneficial. Entities connecting early may have a stronger economic case when LIFO-based dispatch algorithms are implemented, as they will be the last customers to be curtailed. In general, utilities integrating flexible interconnection into their business-as-usual practices will allow customers connected under a flexible agreement to upgrade to a firm agreement, provided that they contribute financially to the necessary network reinforcements.

## Business, Economic and Policy Relevance of Flexible Interconnection

Flexible interconnection arrangements supporting higher DER penetrations have the potential to be beneficial to multiple stakeholders, including DER customers, utility ratepayers, and policymakers.

*DER customers* connecting under a flexible interconnection agreement can potentially accelerate connection times while avoiding costly reinforcements. Flexible connections can be a permanent solution provided that the level of export curtailment is financially

sustainable to the project; they can also be a temporary solution allowing DER projects to start generating revenues faster while waiting for completion of scheduled network reinforcements, or for a critical mass of DER projects to connect in the same area, and eventually share the network reinforcements costs enabling transition to firm interconnection.

*Ratepayers* may also benefit from the development of flexible interconnection. Indeed, conventional network reinforcement required under traditional firm connections are funded, in part or total, via distribution and other system charges passed down to ratepayers as authorized by the relevant regulatory entity. Specifically, for larger DER customers, the costs of network reinforcements necessary for a specific DER asset to export (“sole user assets”) are usually fully charged to that customer. However, for smaller customers, part of the upgrade costs may be socialized across all ratepayers. In addition, larger DER customers sharing use of substations with other DER and non-DER customers only pay a portion of the reinforcement costs based on their export capacity, while the remaining costs are socialized across all ratepayers.

*Policy objectives* may benefit from flexible interconnection if it can accelerate progress towards DER penetration goals and/or emission reduction targets. Additional benefits of accelerated DER connections may include positive impacts on the local economy in the form of energy-based financial benefits (e.g. developers offering discounted electricity to local residents), or non-energy-based financial benefits (e.g. growth of tourism, employment of local suppliers and contractors).

## Selected Demonstration Projects at Early-Adopter Utilities

A small, but growing, number of demonstration projects are exploring the feasibility and value of a range of flexible interconnection approaches, including six in the U.K., France, the U.S. and Canada. Case studies profiling these efforts, summarized in Table 3, offer a representative understanding of how flexible interconnection is being applied to both raise industry awareness and inform utility strategic thinking.



Table 3 – Summary of Profiled Demonstration Projects.

Demonstration	Hosting Utility	DER Type(s)	Management Solution Type	Constraint Location	Status
Accelerating Renewable Connections (ARC)	SP Energy Networks (U.K.)	Generation (PV, wind, DG)	Local & Centralized management	Distribution, Transmission	In service since 2016
Smart Grid Vendée	Enedis (France)	Generation (PV, wind)	Local management	Distribution	In service since 2017
Flexible Interconnection Capacity System (FICS)	Avangrid (U.S.)	Generation (PV, DG)	Local management	Distribution	Several sites in development
Automated Load Rejection Scheme (ALRS)	Hydro One (Canada)	Flexible loads	Local management	Distribution	Commissioning planned for Q4 2018 – Q1 2019
Driffield	Northern Powergrid (U.K.)	Generation	Centralized management	Distribution	Commissioning planned for Q4 2018
Dumfries and Galloway	SP Energy Networks (U.K.)	Generation (wind)	Centralized management	Transmission	Being designed, commissioning planned for 2023

### Accelerating Renewable Connections (SP Energy Networks, U.K.)

The U.K. Distribution Network Operators (DNOs) have played a leading role in developing and trialing solutions over the past decade. In particular, the Energy Network Association (ENA) published in 2015 a *Good Practice Guide on Active Network Management* [6]. The Accelerating Renewable Connections (ARC) demonstration [7] was developed by SP Energy Networks in 2013-2016 as a series of projects located in southeast Scotland. This demonstration has leveraged learnings from prior demonstrations in the U.K., including Scottish and Southern Energy Networks’ Orkney Registered Power Zone [8], U.K. Power Networks’ Flexible Plug and Play [9], and Western Power Distribution’s Low Carbon Hub [10]. Its overarching goal is to demonstrate that managed DER connections can serve as temporary or permanent solutions to mitigate network constraints and enable more DER to connect. Both local (managing a single constraint) and centralized (managing multiple constraints across a wider area) management schemes have been deployed, and are currently in service.

The Penmanshield Piggery Farm wind/PV arrangement is an example of the local management schemes demonstrated as part of ARC. Due to a local voltage constraint, it was initially deemed that the interconnection of 100kW of PV and a 100kW wind generator would require the construction of a dedicated overhead line back to the primary substation, at a cost estimated around £740k (\$942k).

However, a closer monitoring of the real-time network characteristics determined that the power demand at the farm always exceeded 50kW, thus allowing 50kW of PV to connect immediately under a traditional “firm” interconnection agreement. The remaining 50kW of PV and 100kW of wind were then able to connect under a non-firm agreement.

Voltage is monitored at 1-min resolution, and data is streamed via General Packet Radio Services (GPRS)<sup>2</sup> to a controller located at a remote data center. When voltages exceed a certain threshold, a curtailment signal is sent to the PV and/or wind systems until voltages return below a release threshold. With this arrangement, the total interconnection cost, including the monitoring and control equipment, was reduced to less than £20k (~\$25k), representing a 98% cost saving compared to the conventional reinforcements approach.

Separately, the Dunbar 132/33kV Grid Supply Point (GSP) is an example of the centralized management schemes demonstrated as part of ARC. In 2008, two wind farms of 62.5 MW and 48 MW were connected downstream of Dunbar GSP. When three additional projects sought interconnection – two wind farms of 7.5 MW and 5 MW, and a 31-MW waste recovery generator – none were initially allowed to connect until 2021, with the expected completion of transmission line upgrades, totaling £14M (\$17.8M), and localized upgrades amounting to £6M (\$7.6M). However, the deployment of a control platform (see Figure 2) that adjusts in real-time the generators’ maximum export limit based on loading levels at Dunbar GSP

<sup>2</sup> General Packet Radio Services (GPRS) is a packet-based wireless communication service comprised of data rates ranging from 56 up to 114 Kbps and continuous connection to the Internet for mobile phone and computer users.



Figure 2 – Controller located at Dunbar GSP (Source: SP Energy Networks)

enabled all three generators to connect earlier than 2021, while sending a clear investment signal to complete the transmission upgrades. While all three generators are currently connected under a non-firm agreement, they will eventually transition to a firm agreement once the reinforcement measures are completed in 2021. In this example, the managed connection is being used as a stop-gap measure.

### Smart Grid Vendée (Enedis, France)

In France, a primary driver for developing flexible interconnection arrangements is the avoidance of costly construction of new dedicated feeders—a measure that is usually required for distribution-connected generators larger than 8 MW. These dedicated feeders average 10-13km in length, at an average cost of roughly €1M (\$1.27M). Enedis, the French distribution operator, has started to offer alternatives, including allowing larger wind and solar PV sites to connect via multiple firm connection points when no single existing feeder has headroom available to accommodate the full power export capacity requested.

The *Smart Grid Vendée demonstration* [11], located in west-central France, is exploring flexible interconnection to address constraints on the primary distribution network that are limiting DER connections. The demonstration, in service since 2017, is evaluating two

types of flexible arrangements. The first approach, most commonly demonstrated in other service territories, is framed in terms of instantaneous *power export* capacity. It was applied to a 11.7-MW wind farm initially requesting firm interconnection, which was deemed to require the construction of a new 12-km feeder. Instead, 10 MW were connected under a firm connection agreement to an existing feeder with headroom available via a new 1-km line. The remaining 1.7 MW were connected under a flexible agreement that, based on grid conditions, grants Enedis the ability to curtail the farm's production from 11.7 MW down to 10 MW in increments of 0.1 MW. This approach accelerated the project's connection time by eight months.

A second type of flexible interconnection agreement was implemented for a 5 MV solar PV site, based on an agreed-upon, contractually-guaranteed level of annual *energy exports*. Should Enedis curtail more than this annual kWh quantity, the producer will be compensated for the difference based on the relevant export tariff. Under this approach, the PV site was able to connect to an existing feeder, only requiring construction of a new 30-meter line instead of a new 4-km dedicated feeder. As a result, the PV array's connection time was accelerated by three months.

Enedis is currently incorporating these flexible interconnection approaches into business-as-usual processes. It estimates that 700 MW to 1 GW of distribution-connected generation may connect under a flexible interconnection agreement in its territory by 2025. DER sizes benefiting the most from these arrangements are expected to be around 3-6 MW.

In parallel, Enedis is also evaluating the use of active power management schemes to increase substation utilization. Its substations are currently designed assuming 20% of peak demand and 100% of power export capability for all generators connected downstream. Regional planning teams anticipate connection requests and initiate network reinforcements accordingly. DER assets subsequently connecting pay an apportionment of the corresponding construction costs. However, operating substation limits may be better utilized provided that Enedis can curtail exports when approaching the substation operating limits. When multiple generators are connected downstream of the same substations, the generation units with the highest marginal costs are curtailed first. If all units have a zero-marginal cost (e.g. PV or wind), curtailment is proportional to the forecasted production of each generator. Curtailed generators are compensated financially, and these costs are socialized across all exporting generators.



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In ENEDIS’s service territory, distribution-connected generators above 250 kVA are equipped with a standardized local controller (known as “DEIE”, its French acronym) that reports export levels via GPRS to a central controller located at a regional control center; the local controller can also receive curtailment signals (see Figure 3). The central controller updates its constraints forecast every 10 minutes, and sends curtailment signals every 30 minutes to the local controllers, as needed. The generator has 30 seconds to execute the curtailment signal before being disconnected. If communication is lost, the local controller activates a fail-safe mode and curtails exports to a pre-defined value, usually 0 MW.



Figure 3 – Example DEIE implementation (Source: SMA)

**Flexible Interconnect Capacity Solutions (Avangrid, U.S.)**

Avangrid is one of the first U.S. utilities to explore the feasibility and value of flexible interconnection. As part of its Flexible Interconnect Capacity Solutions (FICS) demonstration funded through New York’s Reforming the Energy Vision (REV) initiative [12], it is trialing flexible interconnection arrangements using local management schemes that leverage real-time sensing and controls to avoid more expensive upgrades. Two DER projects were initially identified as potential candidates for flexible interconnection: a 2-MW solar PV farm, and a 450-kW farm waste generator on a bus with 4-MW of existing PV and 500-kW of existing distributed generation<sup>3</sup> (see Table 4). Additional sites are, as of this writing, being investigated.

Table 4 – Illustrative example of a pre-determined time-differentiated operating schedule.

	DER #1	DER #2
DER Requesting Connection	2 MW PV	450 kW DG
Limiting Constraint	Feeder voltage	Substation reverse power
Firm Interconnection Cost Estimate	\$290k	\$3.9M
Flexible Interconnection Cost Estimate	\$125k	\$130k
Avoided System Upgrades	Avoided line regulation	Avoided power transformer upgrade
Generation Curtailment Estimate	<12%	<5%

In general, customer acquisition has been more difficult than anticipated in the FICS initiative, as is often the case in demonstration projects. Areas with specific constraints must be targeted, which can limit the options for participation. Additional challenges include DER projects being delayed or canceled due to permitting or land rights issues, or because developers prefer to wait and see whether other projects ahead of them in the interconnection queue and holding export capacity will actually get built. Successful flexible interconnection demonstrations have generally involved network constraints that are too expensive to address in a timely fashion and one or several DER sites that are strongly motivated to start exporting as soon as possible, even under non-firm conditions.

In parallel, Avangrid is working with several software vendors to integrate multiple software tools into a seamless IT platform that can help accelerate the interconnection process. Integrated software tools include an online interconnection portal, an interconnection administration software, a distribution analysis software used to analyze DER grid impacts and network constraints, a geographic information system (GIS), and customer information and billing systems (see Figure 4). Avangrid plans to eventually incorporate flexible interconnection evaluation into its business-as-usual interconnection planning and analysis process.

**Automated Load Rejection Scheme (Hydro One, Canada)**

While most flexible interconnection demonstrations have focused on allowing more DER generation to interconnect, Hydro One’s Automated Load Rejection Scheme (ALRS) initiative focuses on

<sup>3</sup> While the PV project is currently under construction, the wind farm project ended up leaving the interconnection queue but project developer has expressed interest in re-entering the connection process.



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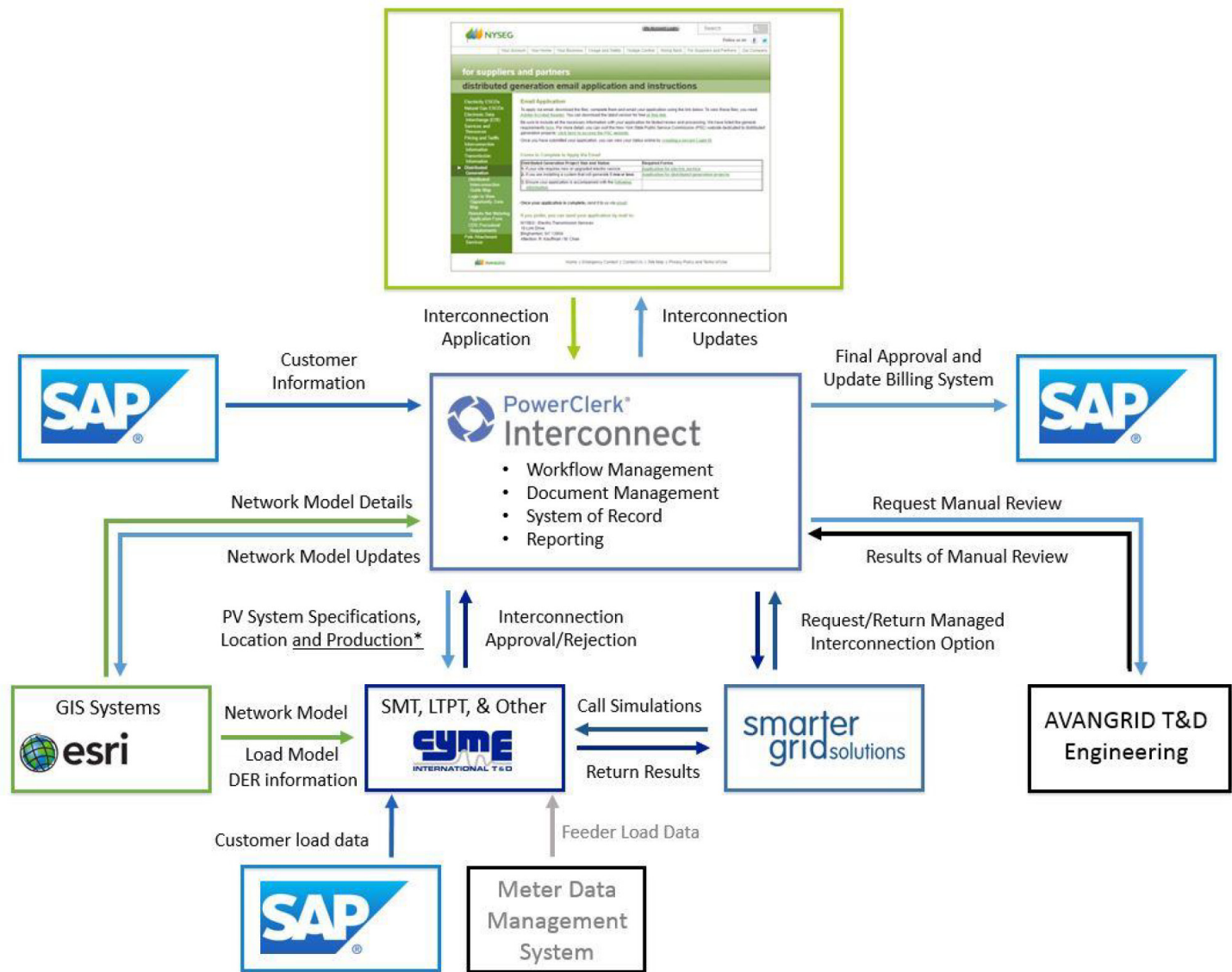


Figure 4 – Avangrid’s integration platform under development integrating multiple tools and systems (Source: Avangrid)

addressing network limits that are preventing load growth [13]. In thermally-constrained areas where system upgrades are required, customers traditionally have had the choice between financing reinforcements and connecting once expansion is complete, or deferring connection until an external change occurs (load defection, socialized reinforcements) allowing them to be connected without violating operating limits.

Hydro One initially envisions applying flexible interconnection to loads as a stop-gap measure: in constrained areas, additional loads may be considered for interconnection up to 95% of the design limits, provided that customers agree to turn down their consumption in contingency situations requiring load transfer. In parallel, Hydro One is also re-evaluating its distribution operating limits to potentially connect more load under firm agreements (see Figure 5).

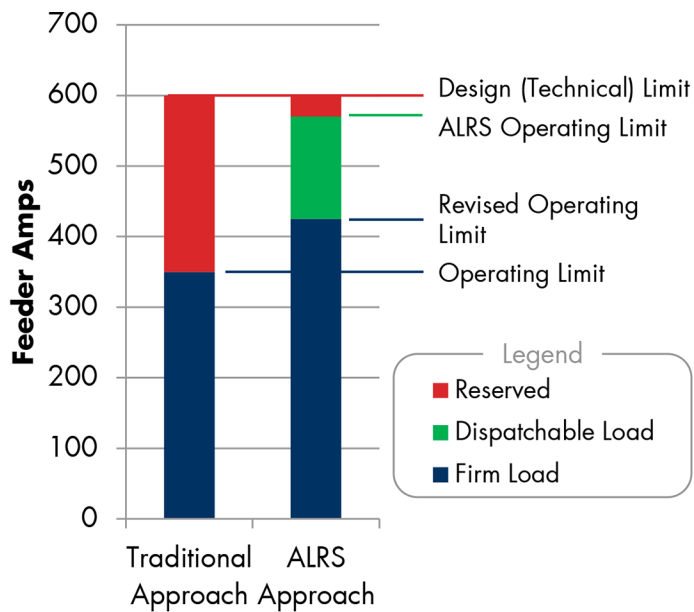


Figure 5 – Approach for ALRS initiative (Source: Hydro One)

To trial the ALRS approach, Hydro One identified two neighboring transformer substations getting load connection requests exceeding their capacity. Three customers are expected to begin participation in Q4 2018 or Q1 2019. The solution architecture is similar to other flexible interconnection demonstrations, and involves a DERMS like controller hosted on virtual machines in a control center. This controller receives real-time information from the distribution management system (DMS) on the thermal constraints, and sends curtailment signals to local controllers co-located with the dispatchable loads as required. The approach resembles demand response (DR) control schemes. However, while DR deployments usually focus on incentivizing flexibility from loads already connected under firm connection agreements, the ALRS approach sets this flexibility as a condition to interconnect.

Given the magnitude of the load requests in the area selected for demonstration, Hydro One considers the ALRS initiative as a stop-gap measure: all customers connected under ALRS must commit to network reinforcements, and their dispatchable loads will become firm load upon completion. The main benefit for customers is, therefore, an earlier connection to the grid. However, Hydro One is also considering offering ALRS as a longer-term solution in less congested areas.

### Driffield Demonstration (Northern Powergrid, U.K.)

The distribution network serving the Driffield area (Northern England) [14] experiences seasonal over-generation issues in the summer, with an installed generation capacity of 146 MW already exceeding the overall network generation capacity of 122 MW at minimum demand. However, during the winter season, the theoretical generation capacity of 219 MW at maximum demand indicates available headroom for additional generation exports. Northern Powergrid therefore selected the area to demonstrate a centralized management scheme enabling more DER to interconnect. System commissioning is scheduled for end-Q4 2018.

Two types of conventional network reinforcements were initially considered. A first option consisted of the replacement of the 132/66kV transformers supplying the Driffield network with higher capacity units at a minimum cost of ~£12M (~\$15.3M); this approach could create up to 30 MW of capacity for new distribution-connected generators. Alternatively, dedicated feeders connecting new generators to neighboring substations with available capacity was considered at a minimum cost of ~£6M (~\$7.7M) per user. These upgrade costs were recognized as being prohibitive to new generators seeking interconnection in the area.

The centralized management scheme being deployed consists of a central controller located at Northern Powergrid’s Yorkshire control center, communicating with local controllers co-located with the generators interconnected via a flexible arrangement (see Figure 6). Northern Powergrid’s existing backbone communication network is supplemented with last-mile communication links to each local controller. The central controller runs iterative load flow studies every few seconds to identify potentially binding constraints, taking in real-time measurements from monitoring devices deployed at key locations, and measurements of the generator exports relayed by the local controllers.

Comparing the load flow results to the distribution equipment ratings, the central controller issues curtailment signals to the generators via their respective local controllers, as needed. If no response is obtained from the generators, the associated local controller re-issues a “0” target. If the generator keeps being unresponsive, the local controller activates a circuit breaker and disconnects the generator.

Curtailment commands are issued to participating generators following a LIFO principle. Customers are positioned in the LIFO queue according to the submission date of their interconnection application, provided that they have demonstrated consistent progress towards finalizing their application after that date.

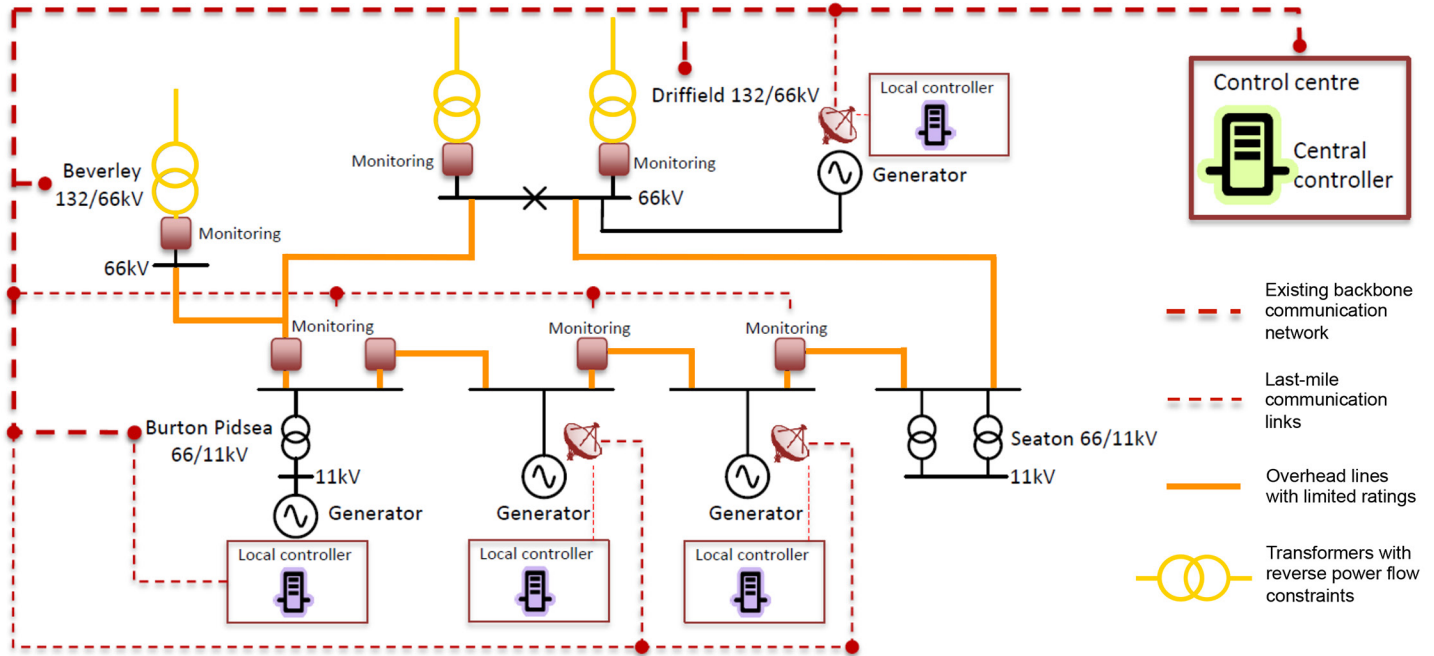


Figure 6 – Driffield centralized management deployment (Source: Northern Powergrid)

Table 5 – Conventional vs. flexible interconnection costs, Driffield demonstration

Conventional Alternatives	Indicative Costs (2018 prices)
Upgrade of 132kV/66kV transformers	Minimum of ~£12M (~\$15.3M)
Dedicated feeders to alternative substations	Minimum of ~£6M (~\$7.7M) per customer site
Managed Control Elements	Indicative Costs (2018 prices)
Shared costs: central controller, shared monitoring devices and communication links	~£900k (~\$1.1M), apportioned per MW
Sole user costs: local controller, local dedicated monitoring devices and communication links	~£100-150k (~\$127-191k) per customer site
Operating costs	Recovered via standard distribution charges

The capital costs of the centralized management scheme, shown in Table 5, are divided into shared costs, and sole user costs. All operating costs are recovered through standard distribution charges. Shared capital costs cover the central controller, and all shared monitoring devices and communication routes. Shared costs are apportioned among participating generators based on their installed capacity (MW), and are re-apportioned over time as additional generators join in. Early adopters initially supporting all shared costs may be eligible for rebates later on (for up to 10 years). Sole user costs cover the local controllers and last-mile communications between the backbone communication network and the customer

sites, and more generally any equipment enabling a single customer to interconnect. Sole user equipment may become shared as additional generators join in.

All new generators above 190kW (200kVA) located in the Driffield area are required to either join the centralized management scheme, or request a conventional firm interconnection agreement and contribute to the associated network reinforcement costs. All conventional reinforcements dedicated to a single customer are entirely charged to that customer. For assets shared with other parties, the customer is charged an allotment based on its use of the asset.



## What about Smaller-scale DER?

Most flexible interconnection demonstrations target DER larger than 250kW, and often at the megawatt scale. Smart inverter functions can help avoid distribution system upgrades at higher DER penetration levels, and are increasingly required under standard, “firm” interconnection agreements. Additionally, a number of regions are now requiring that all smaller-scale DER be capable of responding to curtailment signals.

As of 2015, several Japanese utilities are allowed to implement PV curtailment for residential and small commercial customers; limited curtailment without compensation is permitted by law up to a certain number of hours per year, after which compensation is required. Meanwhile, in Germany, PV generators less than 30 kW must either have a curtailment functionality, or be able to limit feed-in to 70% of rated capacity; the capacity is only to be used during emergency periods. Similarly, Hawaiian Electric introduced PV curtailment into its plans for new PV systems beginning in 2018. The objective is to use a dedicated PV production meter with a disconnect switch to remove PV capacity from the system during emergency conditions. Finally, in France, Enedis is considering using its AMI infrastructure to potentially manage small-scale PV through its Linky smart meters, which integrate a breaker. A load flow controller embedding distribution circuit models has been developed in-house and is intended to be deployed at each substation. The controller is capable of detecting violations of operating limits on the local distribution system, and sending curtailment signals to PV customers via power-line communication (PLC), accordingly. It can also trigger curtailment actions received from a higher managing entity via the AMI cellular link existing between each substation (collecting all local AMI measurements) and the relevant regional control center.

These examples demonstrate that utilities around the world are developing the contractual requirements and technical infrastructure needed to potentially send curtailment and/or disconnect signals from a DERMS-like control platform down to residential or commercial DER assets. However, these features have not yet been incorporated into flexible interconnection agreements that aim to defer costly system upgrades and/or increase distribution network utilization.

## Dumfries and Galloway (SP Energy Networks, U.K.)

The distribution network in Dumfries and Galloway (Southern Scotland) [15,16] is subject to an export constraint due to insufficient capacity on the local 132-kV transmission network at times where peak generation is coincident with low demand, even under normal operating conditions. The area has one of the highest proportion of connected DER relative to its energy demand in the U.K., with 90 MW already connected and an additional 200 MW contracted to interconnect in the future.

Until completion of a long-term transmission upgrade expected in 2023, any new DER project must connect via the Load Management Scheme (LMS), an existing monitoring and control platform capable of disconnecting DER to protect against transmission constraints. The LMS follows a basic operation scheme: responses are based on a pre-programmed worst-case scenario, whole generation sites are disconnected regardless of the actual capacity remaining in the network, and reconnection occurs via manual signals sent from the control center (which can take hours). As a result, the LMS often disconnects more DER than necessary to alleviate the constraints, and incurs long reconnection times. Under these conditions, SP Energy expects that few of the 200 MW contracted would actually connect to the grid before completion of the transmission reinforcements in 2023.

For these reasons, Dumfries and Galloway was selected to demonstrate a centralized active power management solution. The project started in 2018, and one-third of the net benefits are expected to occur before the transmission upgrade is in-service in 2023. Further benefits are expected from 2028 onwards when transmission constraints are expected to re-occur in the area.

The control architecture is similar to Northern Powergrid’s Driffield demonstration, although it covers a wider area, including 11 Grid Supply Points (GSPs) within the transmission network. Dumfries and Galloway is also one of the first demonstrations designed to alleviate transmission constraints using distribution-connected DER, which requires additional coordination with the transmission operator. A central controller monitors the state of the network in real-time via current and voltage measurements on transmission circuits and substations. It also monitors the status of the transmission network circuit breakers. With this information, the central controller manages the DER output via co-located local controllers (instead of simply disconnecting them like the LMS) through a



communication network with low latency (typically <1s) and high uptime (typically >99.9%). Fiber optic cables and/or satellite communications are the communication methods envisioned to meet these requirements.

Several approaches are being considered to determine the order of dispatch: LIFO, based on rank in the interconnection queue; least MW removed from the entire system; and most commercially efficient dispatch, taking into account generator constraint payments where these exist.

SP Energy evaluated the expected quantifiable benefits from implementing a centralized active power management solution in Dumfries and Galloway. Five quantifiable benefit categories were considered, as shown in Table 6, and the total gross benefits were estimated to be £40.2M (\$48.9M), while the total project cost was estimated at £10.1M (\$12.9M).

The central controller is the single largest cost element of the project. SP Energy chose to source a central controller that has the capability to be rolled-out across SP Energy Networks' entire distribution service territory for unlimited MW or number of sites, although it will initially solely manage the Dumfries and Galloway region. This approach is expected to be more cost effective, compared to incremental area-specific applications.

*Table 6 – Estimated costs and benefits for the Dumfries and Galloway demonstration*

Categories	Expected Values
Total project costs	£10.1M (\$12.9M)
including sole user costs + maintenance costs	£2.1M (\$2.7M)
Total quantifiable benefits through 2031	£40.2M (\$51.2M)
Value of carbon benefit (521,717 tons of CO <sub>2</sub> e avoided)	£21.3M (\$27.1M)
Value of reduced system imbalance	£2.2M (\$2.8M)
Value of reduced constraints to existing DG	£7.4M (\$9.4M)
Local economic benefit	£2.5M (\$3.2M)
Value of future avoided expenditure	£6.8M (\$8.7M)

## Key Learnings and Emerging Requirements Supporting the Successful Introduction of Flexible Interconnection Products

*Stakeholder engagement is key to ensuring successful implementation of flexible interconnection agreements.* Greater interaction with prospective applicants is required given the increased technical and commercial complexity of flexible interconnection compared to firm interconnection. This engagement can help prospective applicants understand whether their project specifics are compatible with a flexible interconnection approach. (Note: In some cases, this might require ad-hoc monitoring for some time to better assess opportunities.) It can furthermore facilitate the development of interconnection offers that provide estimates of the annualized level of curtailment.

Estimating how curtailment levels will vary over time can be challenging since it can depend on a number of evolving and dynamic factors (e.g. demand growth or deflection, demand flexibility, DER penetrations, etc.). For these reasons, early-adopter utilities are often forming provisional interconnection teams that specialize in flexible interconnection products. Increased coordination between internal utility stakeholders and processes is also necessary to address the increased level of complexity within flexible interconnection arrangements. Several utilities developing plans to automate interconnection studies to help speed up the interconnection process are integrating flexible interconnection as an option to integrate into their new business-as-usual practices.

*Geospatial heat maps are an important tool for signaling flexible interconnection opportunities to project developers.* To help customers evaluate their options, several early-adopter utilities are incorporating first-order comparisons of the time and cost to connect under firm or flexible arrangements into their publicly-available hosting capacity maps (see example in Figure 7). For flexible arrangements, indicative curtailment estimates by DER type are also being included. That said, other constraints including land availability and cost, zoning permits, etc. may come into play and create demand for new DER connection in highly constrained areas that can only marginally benefit from flexible connection approaches.



**Flexible Interconnection for Distributed Energy Resources: Emerging Practices at Early-Adopter Utilities**

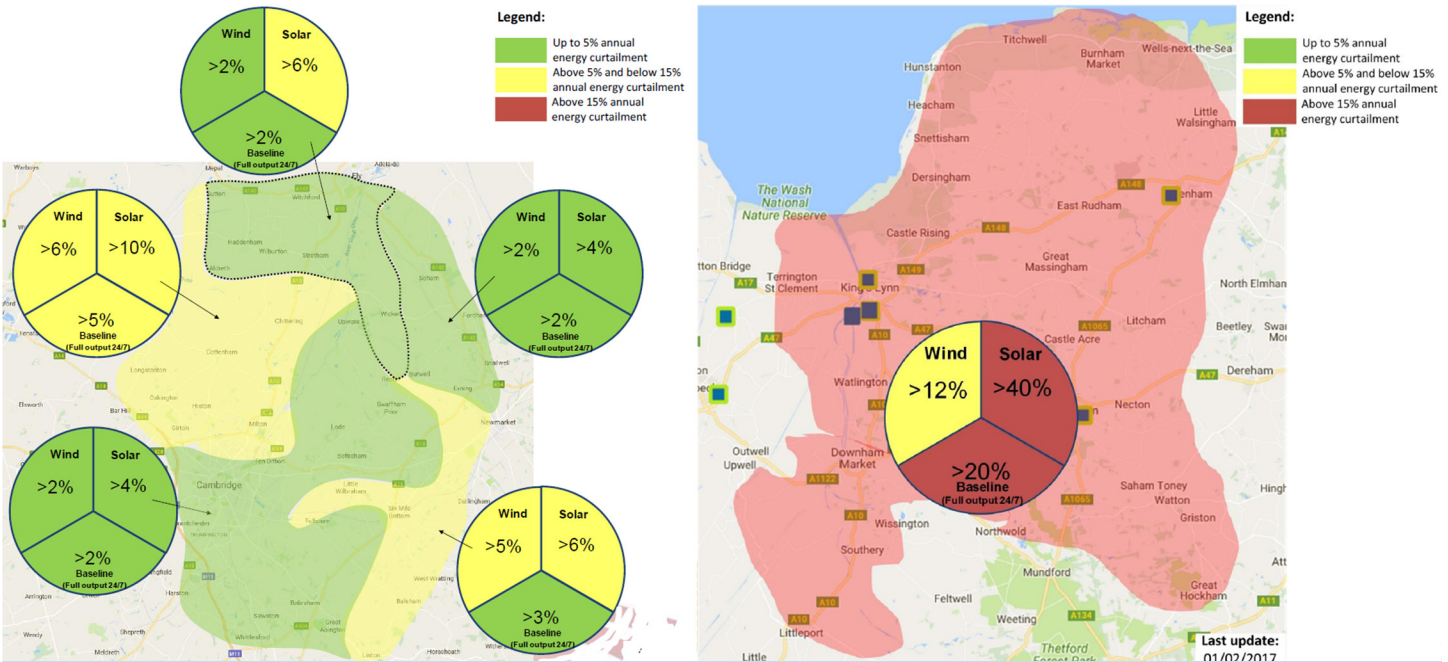


Figure 7 – Assessments of the financial relevance of flexible interconnection alternatives (Source: UK Power Networks (UKPN))

*Visibility and transparency are helpful for enrolling early adopters.* Flexible interconnection offers must provide sufficiently detailed information to enable customers to determine the financial viability of pursuing the arrangement. Dispatch algorithms and re-apportionment rules governing how shared costs are re-distributed as new participants join in must be clearly defined. Constraints triggering curtailment must be logged and audited so that all parties have confidence in the fair application of the rules. Distribution operators may be able to leverage existing dispatch and verification mechanisms developed for the transmission markets to address these emerging requirements.

*Challenging network constraints combined with strong demand for new DER connections are key ingredients of successful flexible interconnection demonstrations.* When reinforcements cost are low and execution times are manageable, risk-averse developers may favor firm interconnection options. When the network is approaching its capacity limits but demand for new DER connections is low, there may not be an interested audience for flexible interconnection options. When demand is strong, connecting customers under a flexible arrangement can also help signal market demand for future network expansions while creating a pool of customers potentially willing to join forces to make the financial cost of infrastructure upgrades commercially palatable.

*Most utility demonstrations to date have focused on solar PV and wind generators.* More recent demonstrations are now applying the concept of flexible interconnection to loads in areas where network constraints are slowing down load growth despite strong customer demand. Battery storage has had a limited role to date. For large-scale energy storage projects, participation in wholesale markets is often a key revenue stream. In this context, export or import restrictions associated with a non-firm interconnection agreement may potentially put the financial viability of these projects at risk by constraining their delivery of services to the wholesale markets. This situation may evolve as new grid support services get defined at the distribution level and packaged into standardized market products that might be more compatible with operating constraints associated with flexible interconnection agreements.

*Early-adopter utilities are experimenting with various dispatch algorithms to govern allocation of export capacity available in real time.* Algorithms based on the LIFO principle have tended to be the most represented to date. Early implementations have based their dispatch order on the submission date of the application for interconnection. However, more recent demonstrations have introduced refinements, taking into consideration the follow through of applicants in finalizing their interconnection agreements in order to potentially gain a more favorable position in the dispatch stack.



“Wait-and-see” applicants have been a challenge in some utility demonstrations, underlying the importance of having proper incentive mechanisms in place to encourage their forward progress.

*Utility demonstrations to date have mostly relied on a separate local controller, co-located with the DER connected under a flexible agreement, to perform a variety of functions.* The controller reports export levels to the centralized utility control system coordinating the allocation of available export capacity, and receives curtailment or disconnect signals. It can also disconnect the DER from the main grid should it become unresponsive to dispatch signals by opening a stand-alone external breaker. While this local controller approach has predominated to date, other solutions might emerge. For example, future control architectures may leverage the circuit breaker integrated into the utility master meter when available. Alternatively, DER inverters may be able to respond directly to signals adjusting maximum export levels or instructing temporary non-export until further notice. All utilities experimenting with flexible interconnection arrangements are incorporating communications fail-safe modes into the technical requirements imposed to DER participants.

*Flexible interconnection is being envisioned as either a stop-gap measure or as an enduring solution, depending on the severity of the network constraints and the demand for new DER connection.* These factors are highly location specific. In some demonstrations, customers connecting under a flexible agreement are required to transition to a firm interconnection upon completion of some ongoing or scheduled network reinforcements. In other cases, an increasing number of participants joining under a flexible agreement might eventually form a critical mass of customers willing to fund network reinforcements to increase their export capabilities.

*Flexible interconnection projects have thus far focused on real power management, but reactive power compensation is a logical next step and may be part of future utility demonstrations.* This potential evolution in flexible interconnection is tied to advances in DER technologies that are increasingly able to dynamically adjust their reactive power, similarly to active power. Many elements of the technical solutions trialed for active power management, including the communication and control infrastructure, are directly applicable to reactive power management.

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