ESB NETWORKS
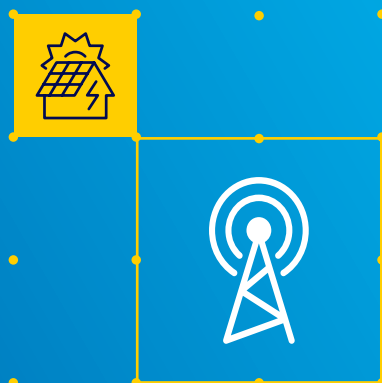
Signals & Data Exchange Guidance for DER

NATIONAL NETWORK, LOCAL CONNECTIONS PROGRAMME

OPENING STATEMENT

The decarbonisation of Irish society relies on fundamental changes to how energy is generated and consumed. To enable these changes at the right pace and the right price, we will rely on the electricity network, and we need to make the connection between how renewable energy is generated, and how we use or store it. Every Irish home, farm, community, and business is being called on to play a part. The National Network, Local Connections Programme has been established to work with, and for, customers to make this possible.

We are entering a period of rapid change and uncertainty. Over the coming years, technologies will change as will the energy needs of Irish homes, farms and communities. We will need to be able to adapt to meet changing needs and emerging challenges. In this document we have sought to develop a proposed plan that accounts for uncertainty and delivers that adaptability.

For example:

1. Iterative piloting and development of processes so that we can learn what delivers the response we need to ensure we maintain a reliable network for our customers and what needs to be done differently as we prepare for a national rollout.

2. Extensive commitment of resources to communications and collaboration, working with partners and customers to understand their needs and how and why they change, so we can better respond and adapt to these needs.

Over the life of this programme we will face uncertainties and risks. If we proceed too quickly, we increase the risk that customers will not be ready, or technologies will not be as mature. But if we do not proceed quickly enough, there is a risk that the solutions will not be in place when then need to be. Without taking the initial steps now, there is a risk that we and our partners could not replicate solutions that we pilot or commence a national rollout until later in the decade.

We will need to commit people and capital to deliver this programme, and we are reaching a critical decision point regarding the level of resources to commit. ESB Networks serves, and is funded by, all electricity customers. All our customers will share in the benefit, but they will also share in the costs and the risk if we act too slowly or too soon. As such, we want to give all customers an opportunity to consult.

1. Do you think we should take a more measured pace and begin to scale closer to 2030, or commit resources needed to begin build towards a national rollout commencing in 2024/2025

2. There are trade offs between different developments in this plan that we could prioritise What do you think we should prioritise, and how will this affect your business.

We need your input to determine the path forward. So please have your say!

CONTENTS

CONTENTS

1 NATIONAL NETWORK, LOCAL CONNECTIONS – HAVE YOUR SAY!

This proposal is the Signal & Data Exchange Roadmap to Requirements for Distributed Energy Resource (DER) Integration. In this document we set out:

1 Proposed standard technology requirements for microgeneration inverters, electric vehicle chargers and heat pumps.

2 Transparency of future signals exchange architecture for local flexibility management.

3 International benchmarking insights and best practice.

In developing these proposals, we have taken time to seek and utilise stakeholder input from round tables and focus groups, as well as to research and utilise exemplar international experiences. This has enabled us to develop the proposed approaches within this document. While we have confidence that these can meet the overall programme objectives, we are open to change and, as a result, we have prioritised this transparent and consultative approach. There were several key dimensions on which we based this document and it is important to us that we develop an understanding of your perspectives, objectives and concerns across each of those.

It may be useful to consider the below questions while reading this document. Please note when responding to this document, it is not necessary to respond to each of the below questions; responding to a specific question or a general response is welcomed and appreciated:

SELECTION CRITERIA
Do you think other technologies should be included?

NUMBER OF CUSTOMERS PARTICIPATING
How could we work to ensure that standard requirements improve the customer experience?

TYPES OF CUSTOMERS PARTICIPATING
Are there other types of customers whose technology needs should be considered?

PILOT TECHNOLOGY
Do you support these standards and are there alternative standards that you think we should consider?

1 NATIONAL NETWORK, LOCAL CONNECTIONS – HAVE YOUR SAY!

It is also important to us that we maximise the overall value of the programme across our stakeholders. As such, we would invite perspectives on additional considerations that we could fold into our approach:

PILOT REQUIREMENTS
Should we begin to work with other organisations (for example the NSAI, the CRU or others) for these standards to become requirements in Ireland? What other organisations?

CUSTOMER & POLICY OBJECTIVES
Do you think these technology standards could contribute to meeting Irish policy objectives (for example relating to climate action or inclusiveness)?

CUSTOMER EDUCATION AND AWARENESS
Are there further opportunities to drive increased customer education and awareness of these proposals?

SUPPLY CHAIN
Are there opportunities for other parts of the supply chain to get involved and be ready to champion, install or commission these technologies for customers?

2

Glossary

2   GLOSSARY

TERM	DEFINITION
ADMS	Advanced Distribution Management System
API	Application Programming Interface
CSIP	Common Smart Inverter Profile
DER	Distributed Energy Resource
DMS	Distribution Management System
DNSP	Distribution Network Service Providers
DSO	Distribution System Operator
EMS	Energy Management System
ENA	Energy Networks Association
EPRI	Electric Power Research Institute
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FERC	Federal Energy Regulation Commission (US)
IEEE	Institute of Electrical and Electronic Engineering
IED	Intelligent Electronic Device
Modbus	A communication protocol for transmitting information between electronic devices over serial connection
PF	Power Factor
RTU	Remote Terminal Unit
SCADA	Supervisory Control And Data Acquisition
Smart Inverter	Smart Power Electronics Device to convert DC to AC power.
TCP/IP	Transmission Control Protocol/Internet Protocol
TSO	Transmission System Operator
Volt/Var	Voltage and Reactive Power Control
Volt/Watt	Voltage and Active Power Control
V2G	Electric Vehicle to Grid

3

Overview

3 OVERVIEW

DERs are resources connected to the distribution system close to the load, such as Solar Photovoltaic (PV), wind and energy storage (e.g. battery). Energy efficiency, demand response, and electric vehicles' (EVs) batteries are also sometimes considered as DERs. These resources may be deployed individually, co-located, or aggregated and, in some cases, jointly controlled.

The significant feature of new clean energy technologies is that they can be deployed in small scales and within the distribution system, unlike traditional fossil fuel-based generation that exists as large central plants within a bulk system.

DERs can be connected to distribution grids, ranging in scale from just a few kW to a few MW for third-party and utility-owned systems.

As power systems transition to a greater dependency on DERs, the systems used for integration of same will be more complex for the following reasons[1]:

• DERs come in many types (PV, battery storage, fuel cells, electric vehicle charging, demand response load, heat pumps), each with their own power characteristics and capabilities.

• DERs are deployed in many sizes, from small residential to large commercial and utility scales within the distribution system network.

• DERs are connected in diverse locations where supply and power quality constraints may exist.

• DERs are owned by a range of entities, each with its own objectives and priorities, which may at times conflict with the goals of grid operators.

• Telecommunications networks for DERs may not be as fast, reliable, or secure as those used for bulk generation.

DERs, especially inverter-based technologies such as solar PV and battery energy storage, can provide a wide range of grid-supportive services, including those that respond to local voltage and frequency variations.

In the future, it will be possible to dispatch grid instructions for DER, such as adjustable export limits. Internationally, grid codes are being updated to make DER integration reliable and also aligning to the highest technical standards.

3   OVERVIEW

3.1   ROADMAP TO INTEGRATE LARGE SCALE RESIDENTIAL DER

Electrical utilities around the world are developing the contractual requirements and technical infrastructure needed to interconnect DER resources and potentially send curtailment and/or disconnect signals from a DERMS type control platform down to residential or commercial DER assets.

To facilitate the above, several essential aspects will need to be addressed by ESB Networks.

- Stakeholder Engagement
- Curtailment
- Heat Maps
- Visibility
- Network Constraints and Increased Uptake of DER

3.1.1   STAKEHOLDER ENGAGEMENT

Stakeholder engagement is key to ensuring successful implementation of DER resources. 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.

3.1.2   CURTAILMENT

Estimating how curtailment levels will vary over time can be challenging since it can depend on several evolving and dynamic factors e.g. demand growth and DER penetrations, etc. For these reasons, utilities in the US and Europe are often forming provisional interconnection teams that specialise 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.

3.1.3   HEAT MAPS

Geospatial heat maps are an important tool for signalling flexible interconnection opportunities to project developers. To help customers evaluate their options, several utilities around the world are incorporating first-order comparisons of the time and cost to connect under firm or flexible arrangements into their publicly available hosting capacity maps.

3.1.4   VISIBILITY

Visibility and transparency are helpful for enrolling early adopters of DER. Offers must provide sufficiently detailed information to enable customers to determine the financial viability of pursuing the arrangement. Dispatch algorithms and rules governing how shared costs are redistributed 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.

3 OVERVIEW

3.1.5 NETWORK CONSTRAINTS AND INCREASED UPTAKE OF DER

Challenging network constraints combined with strong demand for new DER connections are key ingredients of successful and flexible DER integration. When reinforcement cost are low and execution times are manageable, risk-averse developers may favour 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 viable.

3.2 NEXT STEPS FOR DER DATA & SIGNAL GUIDANCE EXCHANGE REQUIREMENTS REFERENCE GUIDE

- October 2021: Public Consultation for Data and Signal Exchange Requirements Roadmap Guidance.
- October – December 2021: Incorporation of Public Feedback into Guidance material.
- December 2021: Summary Documents for Customer's DER systems Network Integration.

3.3 ESB NETWORKS STAKEHOLDER FEEDBACK QUESTIONNAIRE

1 What are the technical challenges faced by each industry sector in integrating DER?

2 What interoperability functions are needed to help address the challenges and realise the value of DER?

3 What interoperability capabilities are available now for consideration in DER minimum technical standards? What capabilities will be required in the future?

4 What are the priority interoperability capabilities to be taken forward in minimum standards over the next number of years?

5 What developments exist in communications, data, and interoperability systems, for consideration in future DER minimum technical standards?

6 Should the DER Data and Signal Exchange Guidance be developed by a sector of industry participants, as a basis for review and inclusion in future minimum DER technical standards, and if not, what, other options should be considered?

7 What are the implications of mandating in the initial standard for additional testing to confirm that smart inverters can meet the ESB Networks obligations to manage their network safely and reliably?

8 To operate the power system securely, a level of certainty is required to ensure new installs can satisfactorily withstand a distribution level fault on the network. Are there new solutions available that provide a high level of certainty in achieving this objective?

9 Do you suggest any changes/additions to this document? What and why?

10 Do you find this document beneficial and clear to understand? Please provide feedback.

3   OVERVIEW

3.4   DATA AND COMMUNICATIONS CHALLENGES FOR DER INTERCONNECTION

In 2019, the Distributed Generation Integration Collaborative (DGIC) Working Group highlighted Data and Communications as the No 1. challenge for DER Interconnection [2].

The group isolated 2 key areas of focus for data and communications to facilitate DER interconnection:

1

Determination of the data required to interconnect energy storage as well as data maintenance requirements for system operator management.

2

Approaches for enabling IEEE compliant communication protocols, monitoring, and control of DERs by the system operator or 3rd party aggregator.

Several high priority actions linked to data and communications emanated from this DGIC working group,[2] including:

• Establish real-time communication between DERs and the system operator based on a meaningful SCADA/DERMS standard or operational minimum requirement.

• Determine what data is needed from energy storage to support interconnection.

• Define the accuracy requirement for DERs to provide data - kW, kVAr and V.

3 OVERVIEW

THE DOCUMENT IS STRUCTURED AS FOLLOWS:

SMART GRID ARCHITECTURE MODEL (SGAM)

SGAM CENELEC M490 Standard for DER Integration

Functional Description of all the SGAM components / tables

SGAM Use Case

↓

GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

Global Review

USA

Europe

Australia and New Zealand

↓

DER INTEGRATION – TECHNICAL DEFINITIONS & CHALLENGES

Technical Screening for DER Interconnection

DER Smart Inverters – Network Benefits & Controllability

DER Interconnection Global Standards

↓

ESB NETWORKS TECHNICAL REQUIREMENTS

Functional and Non-Functional Requirements

Provide ESB Networks SGAM Architecture

ESB Networks & DER Responsibility Matrix

Outline High Level Guidance DER Assessment & Testing

4 Smart Grid Architecture Model

4.1 DESCRIPTION

This section of the document will outline the key principles of the SGAM (Smart Grid Architecture Model) Standard. The SGAM CENELEC framework and its methodology are intended to present the design of DER integrated smart grid use cases in an architectural and technology-neutral manner. In accordance with the scope of the M490 program, the SGAM framework allows the validation standard of smart grid use cases and their support by internationally recognised standards.[3]

4   SMART GRID ARCHITECTURE MODEL

4.2   SMART GRID CONCEPTUAL MODEL PRINCIPLE

The SGAM framework consists of five layers representing business objectives and processes, functions, information exchange and models, communication protocols and components. Each layer covers the smart grid plane, which is spanned by electrical domains and information management zones, see Figure 1. The intention of this model is to represent on which zones of information management interactions between domains take place. It allows for the presentation of the current state of implementations in the electrical grid, but furthermore to depict the evolution to future smart grid scenarios by supporting the principles of technological flexibility and interoperability.

FIGURE 1 **SMART GRID XY PLANE** [3]
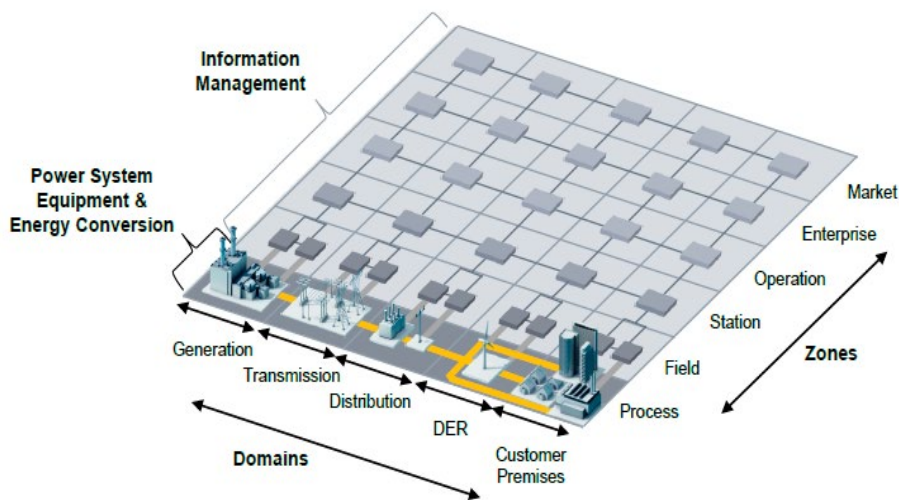
The SGAM framework (Figure 2) is established by creating a Z plane on top of the X and Y axis from Figure 1.

FIGURE 2 **SGAM FRAMEWORK** [3]
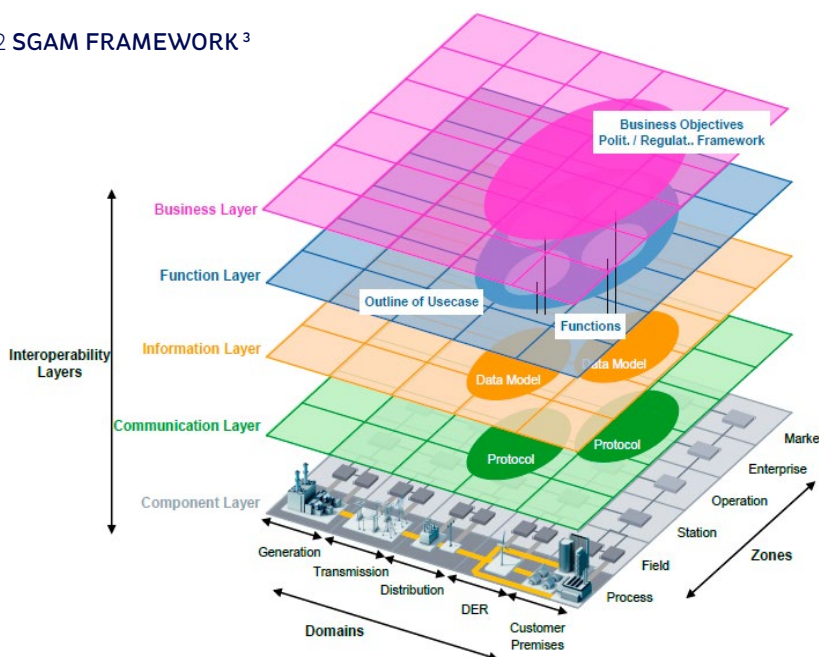
4 SMART GRID ARCHITECTURE MODEL

4.3 SMART GRID PLANE

In general, power system management distinguishes between the electrical process and information management viewpoints. These viewpoints can be partitioned into the physical domains of the electrical energy conversion on the X plane and the hierarchical zones (or levels) Y plane for the management of the electrical process. This smart grid plane enables the representation on the levels of which power system management interactions, between domains or inside a single domain, take place.

TABLE 1 X PLANE - DOMAINS

DOMAIN	ROLE
Generation	Power Stations on the Transmission Network
Transmission	Transmission System Operator
Distribution	Distribution System Operator
DER	**D**istributed **E**nergy Resources - Directly connected to the distribution grid, for example applying small-scale power generation technologies. Microgeneration technologies such as photovoltaic (PV), battery storage and integrated battery storage electric vehicle charging systems (Vehicle to Grid). Click link here for more information.

TABLE 2 Y PLANE - ZONES

ZONES	DESCRIPTION
Process	Physical Equipment
Field	Equipment to Protect, Control and Monitor
Station	Station / DSO
Operation	TSO Control Centre & DSO Control Centre
Enterprise	Enterprise Services Systems
Market	Electricity Market

TABLE 3 Z PLANE INTEROPERABILITY LAYER

INTEROPERABILITY LAYER	DESCRIPTION
Component Layer	Sensors & Equipment
Communication Layer	Communication Devices & Protocols
Information Layer	Power Flow & Data Transfer
Function Layer	Monitoring Information
Business Layer	Different Roles TSO/DSO/Aggregator/Customer

4 SMART GRID ARCHITECTURE MODEL

4.4 SGAM SAMPLE USE CASE ACTIVE/ REACTIVE POWER CONTROL OF A DER UNIT

The following example illustrates how a use case is mapped to the presented SGAM framework for the interconnection of DERs to dispatch active and reactive power services. The use case illustrates a Volt/Watt active (P) / Volt/VAR reactive power (Q) control of a DER unit (required functionality), which falls under the area of the distribution operator on both the MV and LV network. This use case illustrates existing devices, infrastructures, functions, communication, and information standard constraints. The business layer or electricity market interactions are not included at this time. A detailed technical explanation of active and reactive power services will be presented in Section 5 of this document.

4.4.1 COMPONENT LAYER

The component layer Figure 3 depicts the hardware which is central to the SGAM functionality. In this example the components lie in the operation zones downwards. These devices are the dedicated automation systems in the field and in the station zones. The grid is depicted with standard power system equipment (lines, busbars, transformers, generators).

Table 4 provides a comprehensive guide to the component layer functionality.

The colour coding distinguishes the key actors in this example.

- Red – TSO (Transmission System Operator)
- Blue – DSO (Distribution System Operator)
- Yellow – DSO Enterprise Systems
- Green - Aggregator

FIGURE 3 **COMPONENT LAYER**
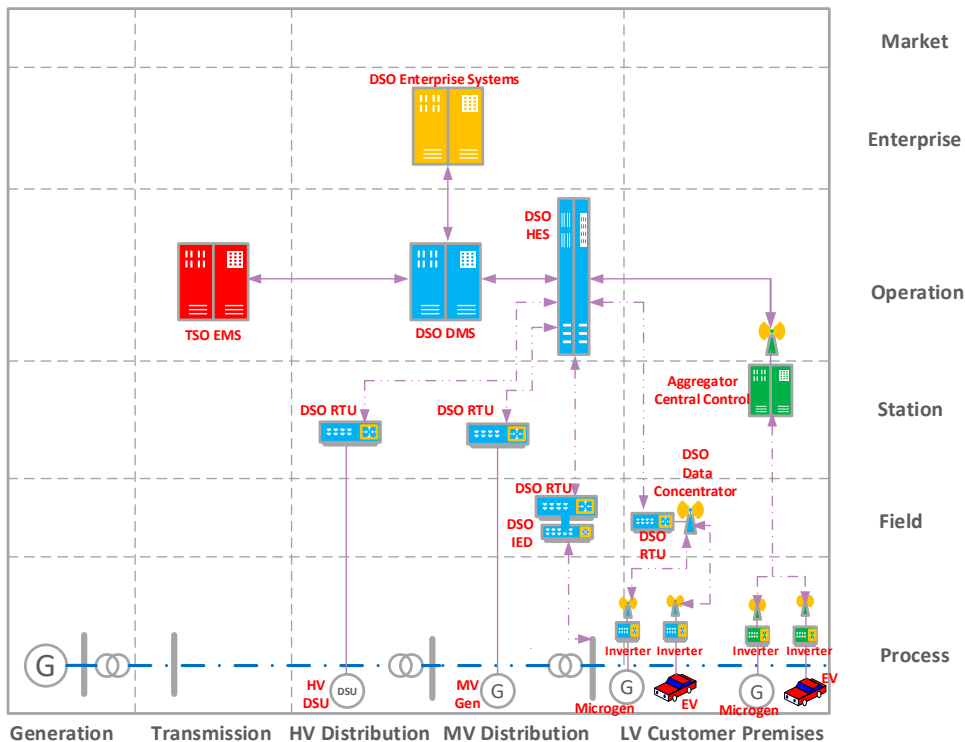
4 SMART GRID ARCHITECTURE MODEL

TABLE 4 **COMPONENT LAYER**	
DEVICE	**DESCRIPTION**
TSO EMS	TSO Energy Management System
DSO DMS	DSO Distribution Management System
DSO Enterprise Services	DSO Service to Carry Out Regulator Report & Audit
Aggregator Central Control	Aggregator Centralised Control Centre
DSO HES	DSO Head End System (Primarily - SCADA) Supervisory Control and Data Acquisition: Centralised system that monitors and controls the electricity distribution network.
DSO RTU	DSO Remote Terminal Unit
DSO Data Concentrator	Data Concentration Gateway
Aggregator Controller	Aggregator Control Unit / Data Concentration Gateway
DSO IED	Voltage Measurement (Intelligent Electronic Device)
Inverter	Smart Power Electronic DC/AC Converter (In this use case the DSO controls the inverter)
Inverter	Smart Power Electronic DC/AC Converter (In this use case the Aggregator controls the inverter)
Microgen	Microgeneration (PV, Wind): see link for more details of Micro Generation Types: Micro-Generators (esbnetworks.ie)
EV	Electric Vehicle Charging Equipment with Integrated DC Battery Storage
MV (10kV & 20kV) Gen	MV Generator on the DSO Medium Voltage Network
HV (38kV & 110kV) DSU	HV Demand Site Unit on the DSO High Voltage Network

4   SMART GRID ARCHITECTURE MODEL

4.4.2 COMMUNICATION LAYER

The emphasis of the communication layer is to describe protocols and mechanisms for the interoperable exchange of information between the use case actors (Customers, DSO and TSO) and components (PV micro-generation, RTUs, etc). Appropriate protocols and mechanisms are identified based on the information objects and data models and by consideration of non-functional requirements of the use case. The communication layer Figure 4 presents the directional communication interfaces for the data exchange of the required information between the components and actors. Table 5 provides the high-level comparison of wired and wireless communication technologies.

FIGURE 4 **COMMUNICATION LAYER**
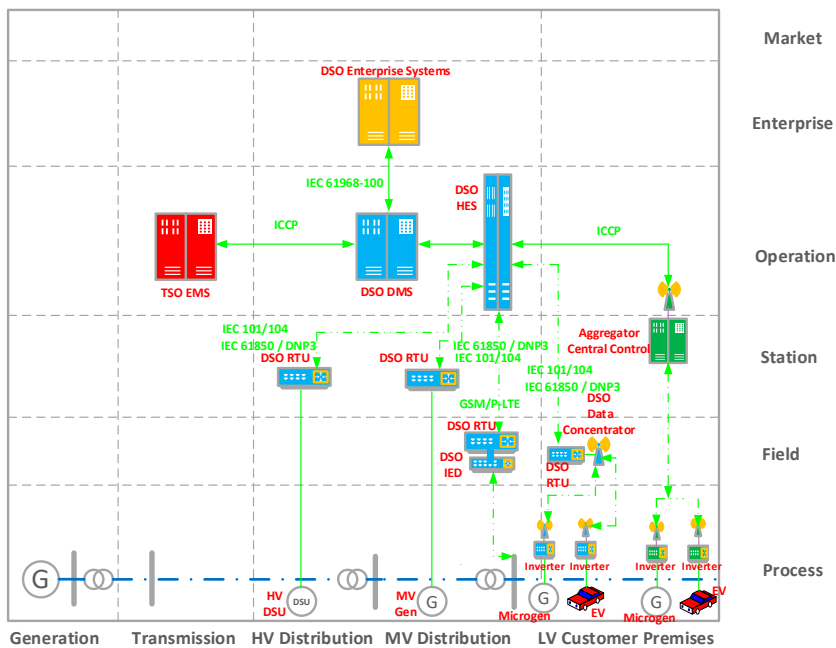
TABLE 5 **COMMUNICATION LAYER**	
COMPONENT	**DESCRIPTION**
←—————→	Physically Wired Connection
←- - - - -→	Wireless Connection

The SCADA based communications protocols for the interface between DSO HES (Head End System) and the DSO RTU for the directly connected customers can be one of the following – IEC 60870-5-101[4] / IEC 60870-5-104[5] / IEEE 1815-2012 (DNP3)[6] / IEC61850[7]. A data concentrator can be used via an RTU to communicate using a secure wireless protocol to the individual DER inverters.

The communications interface between DSO HES and the Aggregator Control Centre connected customers can be a secure ICCP or similar secure communication interface. The communication interface from the Aggregator Control Centre to the DER customers is not specified but shall be DSO approved to ensure it adheres to the highest technical and cybersecurity standards.

4 SMART GRID ARCHITECTURE MODEL

4.4.3 INFORMATION LAYER

The information layer describes the information that is being used and exchanged between functions, services and components. The information exchanges are displayed in Figure 5.

The following is an example (based on this use case) of the sequential flow of the information layer, reviewing Figure 5:

1 MV/LV voltage is monitored by the DSO DMS.

2 The TSO may request, or the DSO may require a change to voltage setpoints to control active (P)/reactive power (Q) on the network.

3 The DSO DMS runs a power flow assessment to calculate possible DER geographic availability/impact on the network.

4 The DSO DMS determines the required voltage setpoints to control active (P)/reactive power(Q) service.

5 Prior to any changes to voltage setpoints, an acknowledgement is sent to the DSO Enterprise Systems of the changes to be enacted (for audit purposes).

6 The DSO DMS requests, via the DSO HES active/reactive power setpoints, to either DSO directly connected customers and/or to the Aggregator Central Control.

7 The DSO DMS monitors the system to ensure the action has been enacted.

FIGURE 5 **INFORMATION LAYER**
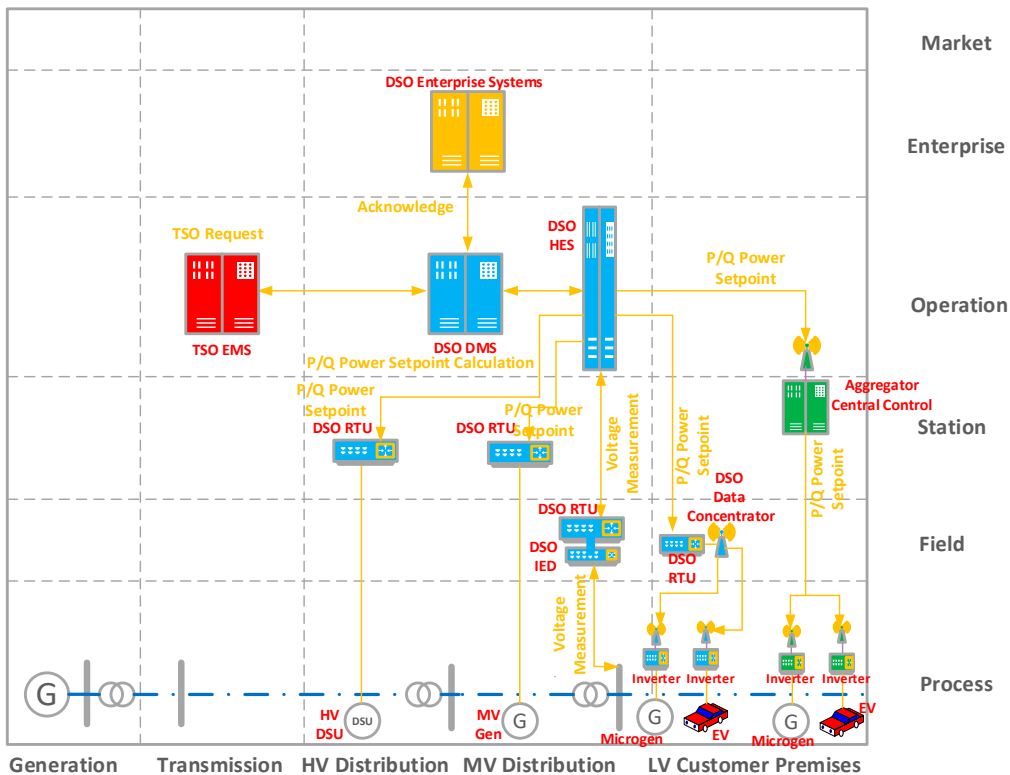
4 SMART GRID ARCHITECTURE MODEL

4.4.4 FUNCTION LAYER

The function layer is intended to represent functions and their interactions in respect to domains and zones. Functions are derived from the use case by extracting its functionality.

The following is an overview of the function layer for this particular use case, reviewing Figure 6:

1 Data Acquisition - The network voltage is measured.

2 SCADA Type Interface - The DSO HES (Head End System).

3 P/Q Calc & Control - The DSO DMS determines DER geographic availability and the required voltage setpoints to control active (P)/reactive power (Q).

4 Audit - The DSO Enterprise Systems is informed of the voltage setpoint change for audit purposes and reporting.

5 DER Control - An instruction is sent from the DSO DMS to control the DERs to provide a network support function.

FIGURE 6 **FUNCTION LAYER**
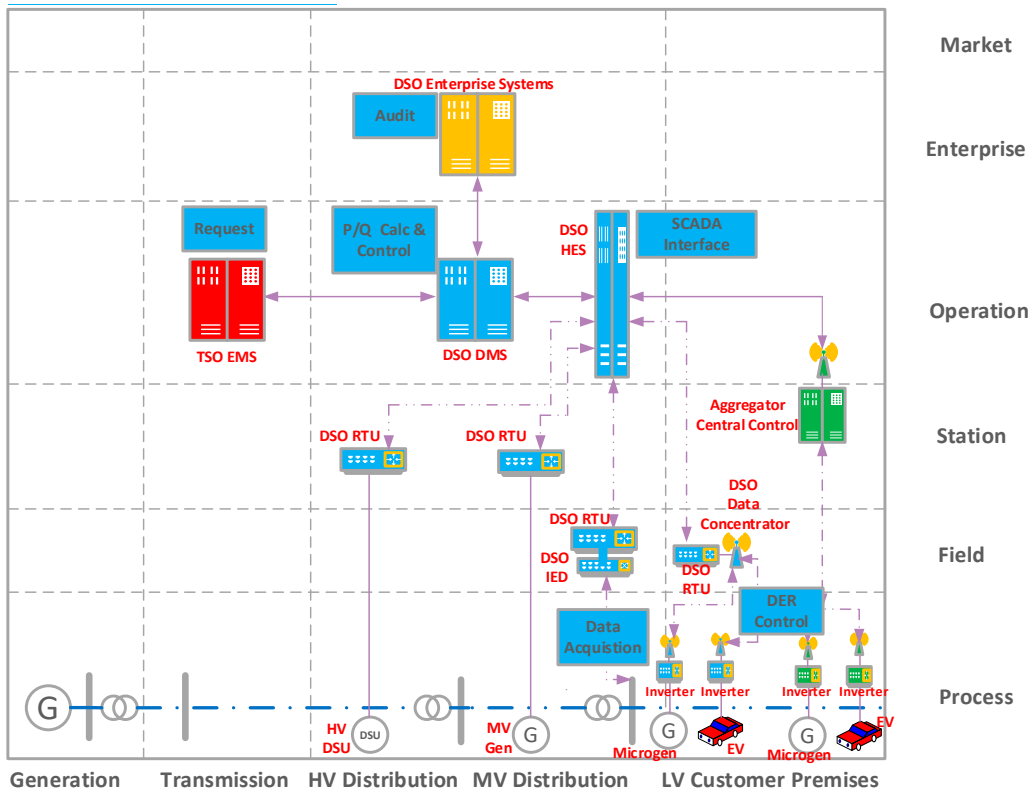
4 SMART GRID ARCHITECTURE MODEL

4.5 REVIEW

The ESB Networks National Network, Local Connection Programme intends to adopt the SGAM architecture for future smart grid development. Please review this approach and provide feedback and comment as appropriate to help shape the DER architecture landscape of the future.

5

Global DER Integration- Current State of the Art

5.1   DESCRIPTION

DERs are resources connected to the distribution system close to the load, such as PV, wind and energy storage. Energy efficiency, demand response, and electric vehicles are also sometimes considered as DERs. These resources may be deployed individually, co-located, or aggregated and in some cases jointly controlled.

According to the US National Association of Regulatory Utility Commissioners (NARUC), these resources "can either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid" (NARUC 2016).[8]

5   GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

5.2   HISTORICAL EVOLUTION OF DERs CONNECTING TO DISTRIBUTION SYSTEMS

A forty-year overview of DER technical review practices provides some useful context for system operators to evaluate existing protocols and to plan. Making the grid available for DER interconnections essentially began with the enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA) in the US [9].

Since then, interconnection practices have evolved roughly alongside the informal DER development timeframes shown in Table 6 below provided by EPRI (Electric Power Research Institute) [8].

TABLE 6 **HISTORICAL DEVELOPMENT OF DER INTERCONNECTION IN DISTRIBUTION GRIDS (EPRI US)** [3]		
YEAR	**DER DEVELOPMENT**	**STATUS OF TECHNICAL REVIEW**
1978 – 1999	Beginning of commercial renewables era.	Mostly manual reviews, several early IEEE DER Guides, review screens added to CA Rule 21 in 1999. [9]
2000 – 2012	Incentives and market growth (increasing renewables system sizes and deployments).	Distribution grid support limited by IEEE 1547-2003; FERC-SGIP 2005 creates "fast track" review and more visibility on screening criteria and process review times. [10]
2013 – 2018	Cost competitiveness (Renewables – mostly PV and wind – becoming economically viable).	Growing pressure from public utility commissions regulators to streamline processes, track review times, and add application portals; IEEE 1547a-2014 allows, then IEEE 1547-2018 requires, grid support. [11]
2018 Onwards	Proliferating solar and battery storage with smart inverters.	More automation expected, DER grid support capacities and penetration levels will need to be considered.

Over this period, incremental progress occurred in technical review practices, including several milestones that define today's technical review process: technical screens (California Electric Rule 21, 1999)[10], interconnection standards (IEEE Std. 1547, 2003)[11] and the fast track process (Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP), 2005)[11]. In the early days, most DER interconnection projects comprised research pilots or large commercial/industrial (C&I) systems using waste fuels and with special arrangements for grid connection. Applications were manually reviewed, and larger connections required studies.

Over the following decades (1980s and 1990s), technical requirements evolved from these early connections to those used today. The rise of renewable generation and the associated shift from synchronous generators to many more inverter-connections significantly affected review protocols and interconnection standards. Around 1999-2000, California regulators added a defined set of technical screens to the state's Electric Rule 21 (Rule 21) tariff. And over the next several years, stakeholders developed and published IEEE Std. 1547-2003 to define technical requirements for certifying DER up to 10 MW. This first release of the IEEE standard restricted active participation of DER in providing grid services (i.e. voltage regulation).

5   GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

5.2   HISTORICAL EVOLUTION OF DERs CONNECTING TO DISTRIBUTION SYSTEMS continued

In 2005, the FERC introduced a technical review process known as the SGIP.10. This process included the idea of Fast Track review for systems not requiring study[11]. Qualifications for fast track were defined by the DER project size relative to the voltage level at the point of common coupling (PCC). Over the next six to seven years, rising solar PV deployments and the need for grid support from DER, potentially via advanced smart inverter functions, became widely recognised. Revisions to policies, procedures, and standards to allow for more grid support from DER were subsequently set in motion. EPRI supported the original definition of grid support functions as well as the early development of smart inverters.[13, 14]

In 2013, both Rule 21 and FERC SGIP began adding grid support requirements, and in 2014, IEEE Std. 1547a subsequently allowed reactive power and ride-through capabilities that were originally limited in IEEE Std. 1547-2003.

Several CA Rule 21 revisions and FERC orders followed that increased thresholds for fast-track review, added the supplemental review option, and raised the fast-track limit for inverter based (smart inverters) DER as a percentage of peak load from 15% to 100%.

In 2015 and 2016, requirements were added for DER reactive power support and ride-through, and efforts to streamline existing interconnection technical review processes became a common theme in many jurisdictions.

In 2018, the revised IEEE Std. 1547-2018 was published [15] , which not only allows grid support, but defines specific DER performance and grid support capabilities. In parallel, several jurisdictions globally began more explicitly ways to improve, potentially through automation, utility application management and technical screening processes.

5 GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

5.3 OVERVIEW OF CONTROL TECHNIQUES FOR DERs

Several managed control methods are emerging from recent and ongoing utility demonstration projects that are suitable for the control of DER resources.

Please review Table 7 below provided by EPRI in in 2018.[16]

TABLE 7 **EMERGING CONTROL TECHNIQUES FOR SYSTEM OPERATORS TO CONTROL DERS** [11]					
CATEGORY	LEVEL OF COMPLEXITY	CONTROL TECHNIQUE	DER MANAGEMENT	NUMBER OF MONITORING POINTS	APPROACH
1	**Fixed constraints**	Timed capacity connection	Single or co-collocated DER	Single monitoring location at DER site	Apparent power at point of connection managed based on pre-determined time-differentiated operating schedule.
2	**Simple, localised constraints**	Export limiting devices	Single or co-collocated 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-collocated 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-collocated 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**	Power management (centralised or decentralised)	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.

5 GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

5.3 OVERVIEW OF CONTROL TECHNIQUES FOR DERs cont

1

Fixed Constraints: These consist of timed capacity connections. Under this approach, DERs 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. The main advantage of this first approach is simplicity. No real-time communications are expected between the system operator 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.

2

Simple, Localised Constraints: Control techniques in this second category aim to manage a single DER, or a set of co-located DERs, to address localised 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.

3

Multiple constraints, potentially nested and/or spanning a wider network area: Control techniques under this category, commonly referred to in Europe as **Active Network Management**, 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 focused to a specific section of the distribution system, a specific substation area, or cover a portion of the distribution system spanning multiple substations.

An increasing number of countries are exploring and implementing the feasibility and value of a range of DER interconnection, including Germany, US, and UK.

5   GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

5.4   GERMANY

The growth of renewables in Germany has been well documented recently. The growth of renewables due to substantial subsidies provided in earlier versions of the Renewable Energy Sources Act, commonly referred to as Erneuerbare-Energien-Gesetz (EEG) regulations, has continued, albeit at a less aggressive growth rate under updated tariff regimes. As of the start of 2018, more than 43 GW of solar PV is in service in Germany, the significant majority of which is located on distribution networks. This is in addition to the 39 GW of wind generation, both onshore and offshore[17].

For small-scale PV, and initially for larger-scale renewables, TSOs were responsible for bringing the forecast production from those resources to market, balancing the system, and paying resource owners according to the feed-in tariff. This is because renewables under the feed-in tariff scheme were covered by a priority dispatch (that is, generation must be taken by the system unless there is a reliability reason not to).

Earlier deployments of solar PV, as well as some other DER, presented an additional issue regarding the behaviour of those resources during system over-frequency events. The configuration of protection on those resources was set to trip at 50.2 Hz. With a substantial deployment of PV already in place, this presented a considerable risk to the continental European system if simultaneous tripping of those resources should occur during a period of high PV output. A program of work was undertaken to manually update the configuration of those resources to resolve this issue in 2013.

5.4.1   GERMAN DER OVERVIEW

As part of the major reform of the renewable feed-in tariff and energy law in 2014 and 2017, several measures were introduced to bring renewable resources into the market and to have them support system needs. One of the main developments has been to introduce the direct marketing paradigm. Direct marketing requires renewable resources to be bid into the market by a balance-responsible party (BRP).[17]

The change required the same principles to be applied to renewables greater than 100 kW as of January 2016. This measure applied to resources built before 2014 that were greater than 500 kW. The measure also changed the format of the feed-in tariff from a flat rate to be based on a market premium; the difference between a reference tariff and the average market revenue from energy. An additional premium is paid to the BRP for the costs associated with bringing the renewable energy sources to market. This reference rate to determine the market premium tariff is updated each quarter or based on the deployment of PV and other DER covered by the scheme.

When redispatch is required, a feed-in management process to curtail DER (called EinsMan) is undertaken by DSOs and TSOs to manage system reliability. This curtailment can affect BRP expected positions, and considerable effort has recently been expended by market parties to develop forecasting capabilities to determine the likelihood of grid congestion restricting the output from DER before market closure, to reduce the potential exposure to TSO balancing costs. Total feed-in management actions in Germany in 2016 resulted in 3.7 TWh of curtailments from renewables and CHP resources on both the bulk and distribution systems (3.5 TWh for wind and 184 GWh for solar)

Germany uses the older IEC 60870-5-104. rather than the newer IEC 61850. communication protocol for DER–DSO communication.

5 GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

5.5 USA – CALIFORNIA

Energy transformation in California has taken a two-step approach: mandatory Distributed Resource Plans (DRP) to be submitted by all investor-owned utilities, outlining their approach to optimum deployment of distribution resources; and 'renewable portfolio standards' that stipulate distributed resource targets for retailers and a 'plug and play' approach to DER integration [18].

California Public Utilities Commission (CPUC), as part of AB 327, has mandated long term plans for all investor-owned utilities (IOUs) outlining a holistic approach to optimum deployment of distribution resources including benefits, costs, tariff structures, incentives, and barriers/mitigations. These will need to show how all IOU's will become network platforms.

The 3 overarching practical exercises requested of each utility by the CPUC are:

1 Identify the full value of DERs to the utility.

2 Specify where on the utility's distribution system DERs best provide value.

3 Propose demonstration projects to prove their conclusion about value and location.

California has similar market conditions to Australia with high electricity prices and strong solar PV uptake levels; however, it has a regulated retail market with most customer served by 3 utilities. It also has high penetration of smart meters and data-sharing tools such as Green Button and Green Button Connect.

California accounts for 50% of distributed solar across the US with 50% growth over the past four years and over 80% of total energy storage. The Net Metering program is being expanded and is significantly driving rooftop solar PV adoption.

The PUC has set centrally mandated targets (50% renewable mix by 2030) which have proved highly effective. Utilities are accountable for defining innovative solutions to reach targets. Distributed resource targets have been consistently outperformed and subsequently raised.

Their proposed DER incentive scheme will allow utilities to earn higher ROICs (Return on Invested Capital) for DERs which is designed to actively encourage less costly DER alternatives to traditional infrastructure. A pilot program has been introduced where utilities are allowed a ROE (Return on Equity) at the upper limit of the "r – k" range, in which "r" is the allowed regulatory rate of return on equity and "k" is the utility's cost of equity.

A recent FERC ruling has allowed DERs, managed by DERPs (Distributed Energy Resource Providers) with load of 500kW, to be aggregated and dispatched into the wholesale market making California the first state in the US to enable this sort of market participation.

5 GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

5.5.1 RULE 21 – DER INTERCONNECTION CALIFORNIA

Electric Rule 21 is a directive that describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system. The directive provides customers wishing to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels.[10]

Each investor-owned utility is responsible for administration of Rule 21 in its service territory and maintains its own version of the rule.

California Rule 21 requires that, by default, Distributed Energy Resources within Investor-Owned Utilities (IOU) must utilise the IEEE 2030.5-2018 networking standard in the manner described in the SunSpec Common Smart Inverter Profile (CSIP), see Figure 7 for details [19].

CSIP was developed as an outgrowth of the California Rule 21 Smart Inverter process to create a common communication profile for inverter communications that could be relied on by all parties to foster "plug and play" communications-level interoperability (outside of out-of-band commissioning) between the California IOU's and 3rd party operated smart inverters or the systems/service providers managing those inverters.

FIGURE 7 **ARCHITECTURAL REPRESENTATION OF NETWORK FOR RULE 21[14]**
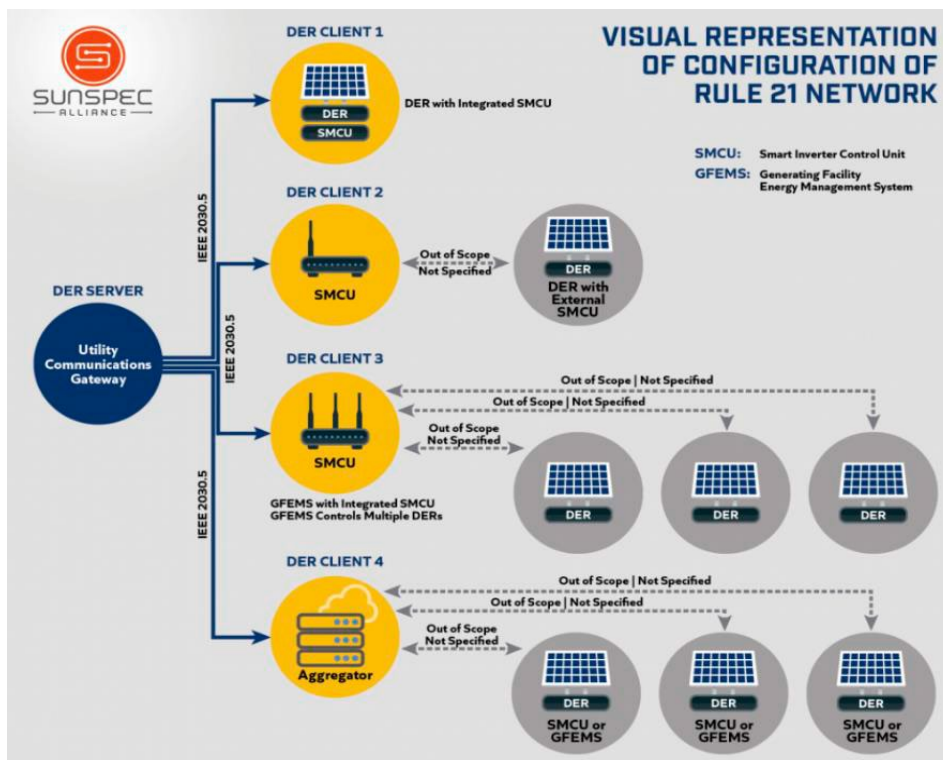
5   GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

5.6   UK

The U.K. Distribution Network Operators have played a leading role in developing and trialling DER solutions over the past decade. In particular, the Energy Network Association (ENA) published in 2015 a Good Practice Guide on Active Network Management [20].

The Accelerating Renewable Connections demonstration was developed by SP Energy Networks in 2013-2016 as a series of projects located in southeast Scotland [21]. This demonstration has leveraged learnings from prior demonstrations in the U.K., including Scottish and Southern Energy Networks' Orkney Registered Power Zone [22], U.K. Power Networks' Flexible Plug and Play [23], and Western Power Distribution's Low Carbon Hub [24].

Its overarching goal is to demonstrate that managed DER connections can serve as temporary or permanent solutions to mitigate network constraints and enable more DERs to connect. Both local (managing a single constraint) and centralised (managing multiple constraints across a wider area) management schemes have been deployed and are currently in service.

5.7   AUSTRALIA

Australia has the highest penetration of residential rooftop solar in the world. In Queensland, 33% of all dwellings have solar installed on their roof. South Australia (32 %) and Western Australia (28%) are not far behind. By 2050, the AEMC (Australian Energy Market Commission) expects more than half of all houses will have solar PV systems and about a third of residential buildings will have energy storage. The Clean Energy Council of Australia has made several recommendations to Distribution network service providers, regional territories, and policy makers[25]:

• Distribution Network Service Providers (DNSPs) should require inverters to have active and reactive power response capability as a condition of grid connection for new DER systems.

• DNSPs that have already adopted static zero-export limitations should invest in network intelligence and move toward dynamic export limitations so that they can utilise DER on their networks more effectively.

• DNSPs should move toward more cost-reflective network tariffs, which could include time-of-use or demand-based charging.

• Connection agreements should allow for the dynamic engagement of DER in the power system, and energy customers should have a right to initiate a review of their connection agreement and the opportunity to receive a better deal.

• Active and reactive power response should be a mandatory requirement in the Australian standard for inverters (AS 4777.2).[26]

• Common standards, protocols and Application Programming Interfaces (APIs) for communication with, and between, DERs are being developed and should be supported and adopted.

• Policy makers should establish market frameworks that will enable DER to supply new energy services. This could include new markets to support grid function, system optimisation (avoiding unnecessary investments) and system balance.

5 GLOBAL DER INTEGRATION – CURRENT STATE OF THE ART

- AEMO and the Australian Energy Market Commission (AEMC) should consider how aggregation of DER can be optimised using a single asset classification. Third-party aggregators should be able to provide wholesale demand response, export, and frequency control ancillary services (FCAS) under a single classification.

- State and territory licensing and other regulatory frameworks should be developed and strengthened to ensure that microgrids can proceed with protections for customers in place and barriers to community energy projects are removed.

- State and territory governments should review their planning and development approvals systems to remove any barriers to developers of new suburbs aiming for very high DER penetration, with minimal grid impacts, using grid-connected microgrids and embedded networks.

5.8 NEW ZEALAND

Transpower, in its role as system operator, has in 2020 published a comprehensive roadmap report on DER expansion in New Zealand [27]. Transpower has identified how critical DER, and its potential flexibility, is to achieve New Zealand's greenhouse gas emissions goals. The report takes a 3-stage approach – looking at establishing the potential value of DER, investigating the potential supply of DER and identifying the barriers to greater access to, and deployment of, flexibility DER offers.

Demand Response will play a key role in Transpower's strategy. Energy efficiency will continually improve the thermal storage inside consumer's buildings (e.g., fridges, freezers, aircon, heat pumps, water heaters, etc.) allowing for greater use of demand management without service degradation. Digitally controlled inverters will allow incremental control of loads to manage demand and service in a fine-tuned way rather than the current scenario of all on or all off. Building automation and smart appliances capable of self-energy management and communicating with external systems are already on the market. Such appliances could be integrated with building automation systems to manage building demand.

Like Australia, Solar PV with battery systems is also called out as another rapid growth area in New Zealand. These views are driven by the generally low residual cost of batteries (net of primary use) and the significant reduction in costs over time for residential PV inverter battery systems. The Transpower analysis indicates significant take-up of residential solar PV with batteries up to 2035 and growing up to 2050.

5.9 REVIEW

This section of the guidance document has provided a comprehensive review of DER development internationally. It focuses on the design and implementation practices for successful DER integration and control. Please review this state of the art analysis and provide feedback and comment as appropriate to help capture a thorough global snapshot of grid integrated DERs approach – looking at establishing the potential value of DER, investigating the potential supply of DER and identifying the barriers to greater access to, and deployment of, flexibility DER offers.

6

DER Integration – Technical Definitions & Challenges

As DER deployment grows globally, there is a need for power system operators and regulators to understand considerations for interconnecting these resources to their electrical systems as well as different solutions that may be suitable given their DER penetration levels, system characteristics, capabilities, and organisational structures [28].

This section of the document focuses on the interconnection requirements and challenges that apply broadly to DER grid integration.

The section is structured as follows:

- Technical Screening for DER Interconnection

- DER Smart Inverters – Network Benefits & Controllability

- DER Smart Inverters and Distribution Energy Resource Management Systems (DERMS)

- DER and EV Interconnection Standards

- Data and Communication Challenges for DER Interconnection – Overview

6 DER INTEGRATION – TECHNICAL DEFINITIONS & CHALLENGES

6.1 TECHNICAL SCREENING FOR DER INTERCONNECTION

Technical screening of DER systems that apply for interconnection is critical for ensuring safe, reliable, and cost-effective interconnection. Power flow modelling can be used by a system operator, in addition to technical screening, to indicate potential DER impacts on the system. Power flow modelling can also be used for calculating hosting capacity and creating hosting-capacity maps, depending on the method used [29]. Several utilities globally are developing plans to automate interconnection studies to help speed up the interconnection process and are including flexible interconnection as an option to integrate into their new business-as-usual practices more precisely.

6.2 DER SMART INVERTERS – NETWORK BENEFITS & CONTROLLABILITY

Many DERs generate power as direct current (DC) and need a method to convert DC to the alternating current (AC) used on the grid and in homes and businesses. Inverters, see Figure 8 from the Use Case SGAM earlier, convert DC to AC and allow PV, battery, and other DC sources to supply local loads.

Smart inverters may be owned and controlled by

- the customer or
- the system operator as shown in Figure 8 or
- an aggregator

to provide supported functionality to the network. Figure 9 compares both types of inverter.

Inverters also tie into the grid and match the local voltage and frequency. These inverters are power electronics with "smart" capabilities. Advanced inverters can also be used to achieve other goals as part of broader grid improvement. Through the integrated use of smart inverters and other legacy voltage-control devices, distribution system operators can regulate entire-feeder voltage.

FIGURE 8 **DER INVERTER INTERFACE**

FIGURE 9 **SMART INVERTER CATEGORIES**

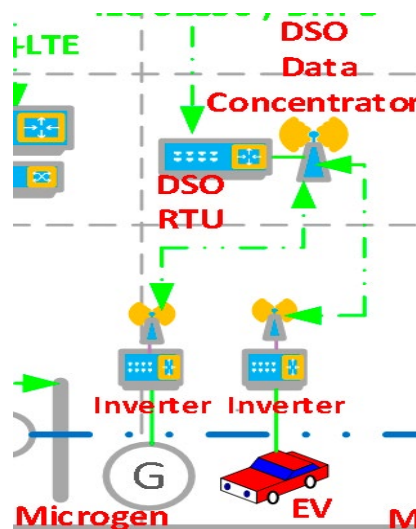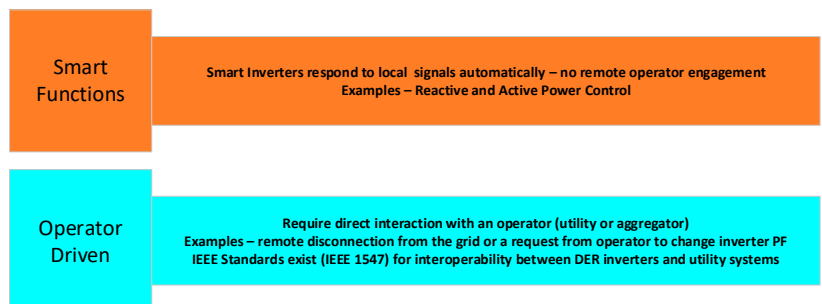| Smart Functions	Smart Inverters respond to local signals automatically – no remote operator engagement Examples – Reactive and Active Power Control
Operator Driven	Require direct interaction with an operator (utility or aggregator) Examples – remote disconnection from the grid or a request from operator to change inverter PF IEEE Standards exist (IEEE 1547) for interoperability between DER inverters and utility systems

6   DER INTEGRATION – TECHNICAL DEFINITIONS & CHALLENGES

6.2.1 SMART INVERTERS AND DERMS (DISTRIBUTION ENERGY RESOURCE MANAGEMENT)

Smart inverters can also facilitate combining local or autonomous control at fast time scales (seconds) with control signals sent from a central operator at a slower time scale (minutes) and could help coordinate between devices or better achieve certain objectives. Distributed systems DERMs (Distributed Energy Resource Management) modules may be able to aid in this effort. DERMs may also modify inverter power factor (PF) and settings, as well as dispatch or broadcast randomised response times for inverters, which would support these functions. All smart inverters are programmed to drop off the grid when voltage or frequency disturbances are detected on the network. For example, in the US, pilots with DSO controlled inverters have been implemented by Arizona Public Service (APS)[30] and the PG&E (Pacific Gas & Electric) Electric Program Investment Charge (EPIC) project.[31]

6.2.2 SMART INVERTERS FOR NETWORK VOLTAGE REGULATION

Smart inverters support distribution networks by providing active (P) and reactive power (Q) injections. Advanced inverters may inject or absorb reactive power (VARs). Injecting reactive power increases the local voltage, while absorbing reactive power decreases the local voltage. This can provide an alternative to potentially expensive distribution upgrades for voltage issues on the LV and MV network.

The 3 most common smart inverter voltage regulation functions are:

1 Constant PF mode

2 Voltage and reactive power control (Volt/Var)

3 Voltage and active power control (Volt/Watt)

Constant PF mode – The smart inverter operates at a constant PF, which is typically not lower than 0.90 so the reactive power does not exceed 44% of the nameplate apparent power rating. Constant PF mode with a PF = 1 (unity PF) setting is usually the default mode of the installed DER as well as the default mode in most standards [28].

Voltage and reactive power control (Volt/Var) - The smart inverter can actively control its reactive power output as a function of voltage following a voltage-reactive power piecewise linear characteristic Volt/Var curve, see Figure 10. For most applications, the Volt/Var curve is predefined, and the smart inverter operates in an autonomous mode.

6 DER INTEGRATION - TECHNICAL DEFINITIONS & CHALLENGES

6.2.2 SMART INVERTERS FOR NETWORK VOLTAGE REGULATION continued

Vref in Figure 10 is the desired network reference voltage. The location of the inverter on a circuit can influence the appropriate Vref value. Vref can be adjusted based on the application of the smart inverter control. During normal operation, the voltage should be kept near the nominal value: Vref = 1.0 per unit (p.u.). For other applications, a different Vref may be required.

For voltage and active power control (Volt/Watt) the inverter can actively control its active power output as a function of voltage following a Voltage/Active power characteristic, as shown in Figure 11. Like Volt/Var control, most applications operate smart inverters under Volt/Watt control in autonomous mode.

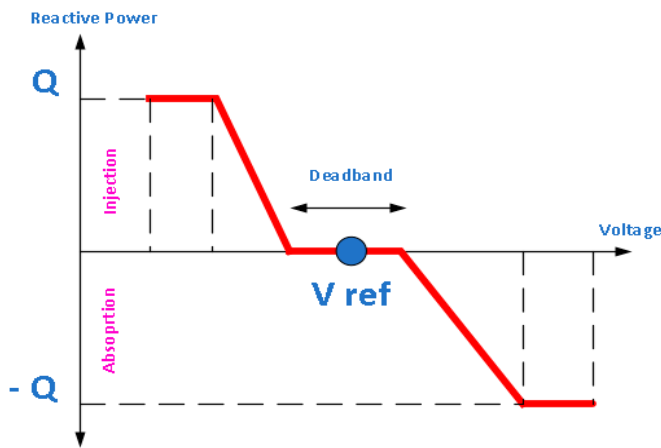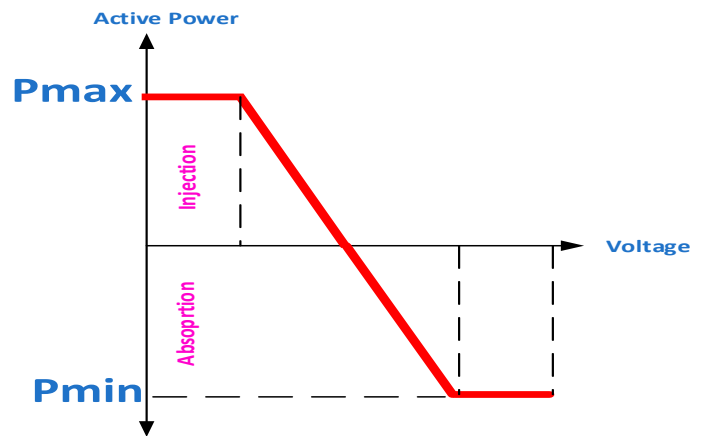FIGURE 10 **VOLT/VAR CHARACTERISTIC**

FIGURE 11 **VOLT/WATT CHARACTERISTIC**

Network voltage instability may occur when using Volt/Var and Volt/Watt modes simultaneously. The IEEE 1547 Standard[12] is designed to create the rules to ensure the safe and reliable electrical interconnection of DER resources.

6 DER INTEGRATION – TECHNICAL DEFINITIONS & CHALLENGES

6.3 OVERVIEW OF DER AND EV INTERCONNECTION STANDARDS

A solid foundation of standards is essential for achieving reliable and safe DER interconnection. NREL (National Renewable Energy Laboratory of the United States) have clearly stated that every system operator should have an interconnection application and approval process that distributed generator developers can follow, and every jurisdiction should have a clear process for ensuring that DER systems are installed correctly and safely[28].

In Ireland, the grid code standards for distribution connection conditions are clearly outlined in the current ESB Networks Distribution Code [32].

The European Electricity Network Codes are a set of technical rules which aim at harmonising the EU internal electricity market. These codes are detailed documents that dictate EU wide standards and requirements covering power generation, demand, grid network operations and wholesale market participation. The implementation of these codes is required by all EU Member states over the next number of years to enable electricity network operators, generators, suppliers, and consumers to operate more effectively in the pan-European electricity market. The Network Code on requirements for Generators (RfG NC) covers network code requirements for grid connection of generators and establishes harmonised connection rules for power-generating modules [33]. The code defines four categories or 'types' A-D of generators, which are based on the maximum capacity of the power generating module and its connection voltage level. Please refer to Appendix B for a detailed breakdown of relevant network codes for Type A –> Type D generators in Ireland.

In Ireland, you can connect microgeneration in parallel with ESB Networks LV system provided it is a single-phase generator rated up to 25 Ampere (6kW) at low voltage 230V or three-phase generator rated up to 16 Ampere (11kW) at low voltage 230/400V. It must also comply with the Conditions Governing the Connection and Operation of Micro-generation (PDF 111KB) [34] and with EN50549-1 (see below for details).

In the UK, micro generation and storage are covered by Engineering Recommendation EREC G98 [35]. EREC G98 covers projects with a capacity of 16A or less per phase or less. If there are multiple generation or storage units connected at the same premises, then 16A is the maximum combined capacity per phase. Projects connected at low voltage (230V single phase, or 400V three phase). All technology must also be type tested under the requirements detailed in EREC G98.

New standards are continuously being developed or revised within international and European standardisation organisations, such as the International Electrotechnical Commission (IEC), International Organisation for Standardisation (ISO) and CENELEC.

At the EU level, the standard EN 50549-1 [36] is a recently revised standard with requirements for generating plants to be connected in parallel with distribution networks. Most EU members agree that it also applies to EVs in all scenarios where they discharge back into the grid. But so far, EN 50549 does not cover adjustable loads (i.e., EVs that are just charging) and therefore the mandatory grid stability requirements are not implemented by EV manufacturers inside the power inverters of today's EVs or the charging stations. Within the same family, the standard CLC EN 50491-12 "Smart grid interface" [37] defines the core principles (control types) for the energy management inside buildings and includes alignment with EV charging standards.

6 DER INTEGRATION – TECHNICAL DEFINITIONS & CHALLENGES

6.3 OVERVIEW OF DER AND EV INTERCONNECTION STANDARDS continued

Internationally, IEC TS 62786 (2017)[38] provides principles and technical requirements for DERs connected to the distribution network. It applies to the planning, design, operation, and connection of DERs to distribution networks. It includes: general requirements, connection scheme, choice of switchgear, normal operating range, immunity to disturbances, active power response to frequency deviation, reactive power response to voltage variations and voltage changes, EMC and power quality, interface protection, connection and start to generate electrical power, active power management, monitoring, control and communication, and conformance tests.

DERs include distributed generation and permanently connected electrical energy storage in the form of synchronous generators, asynchronous generators, converters, etc., connected to the MV or LV distribution network.

Currently, the most mature standard for EV charging and communication is IEC 61851 on "Electric Vehicle Technologies" [39]. It defines safety rules for charging with plugs and cables (AC or DC) and the necessary low-level communication between the charging station and the EV. The mandatory safety "PWM-Signal" can be used to implement a trivial form of the "Managed (home) charging" scenarios (SC.1 and SC.3). However, discharging (bidirectional power flow) cannot be achieved with the IEC 61851 technology.

Used as a layer on top of IEC 61851, the international standard ISO 15118 on "Road vehicles – Vehicle to grid communication interface" [40] defines a high-level communication between a charging station and an EV for the control of charging services. Early EVs are using the first edition of ISO 15118-2 with the view to enable direct current (DC) fast charging. However, due to technical issues resulting from overcomplexity within ISO 15118-2, none of the smart charging scenarios can be satisfied reliably. For that purpose, the revision of this standard has already been launched.

The new standard, known as ISO 15118-20 "2nd generation network and application protocol requirements", was written to enable all smart charging scenarios mentioned above. However, the first publication of ISO 15118-20 is yet to be published and the full set of testing specifications and compliant products should not be expected prior to 2023 to 2025.

Once published, the ISO 15118-20 will deliver the following important new features for smart charging:

• Precise time synchronisation between charging station and EVs (essential for all SC scenarios).

• Multiplexed communication capabilities (helpful for all SC scenarios)

• Dynamic control mode.

• Bidirectional power flow.

• Support for grid code-compliant operation.

• Support for "grid forming" generator behaviour.

Table 8 gives a comprehensive range of the international standards including descriptions/scope for connecting DERs to distribution systems.

6 DER INTEGRATION - TECHNICAL DEFINITIONS & CHALLENGES

TABLE 8 REVIEW OF INTERNATIONAL STANDARDS FOR DER GRID GENERATORS CONNECTION AND OPERATION

LOCATION	STANDARD	YEAR	DESCRIPTION	SCOPE
EU Wide	EN 50549-1	2019	Requirements for generating plants to be connected in parallel with distribution networks– Part 1: Connection to a LV distribution network–Generating plants up to and including Type B generators.	Generating plants up to and including Type B at LV network.
International	IEC 62786	2017	Provides principles and technical requirements for DERs connected to the distribution network.	This document specifies interface requirements for connection of generating plants with the distribution network operating at a nominal frequency of 50 Hz or 60 Hz.
International	IEEE 1547	2020	Standard for Interconnecting Distributed Resources with Electric Power Systems.	DER at primary or secondary distribution voltage.
International	IEEE 2030.5	2018	The application layer with TCP/IP providing functions in the transport and internet layers to enable utility management of the end user energy DER.	Demand response, load control, time of day pricing, management of distributed generation, electric vehicles.
International	IEC 62898-1	2017	Microgrids—Part 1: Guidelines for microgrid projects planning and specification.	AC electrical systems with loads and DER connected at LV or MV.
International	IEC 62898-2	2018	Microgrids—Part 2: Guidelines for operation.	AC electrical systems with loads and DER connected at LV or MV.
International	IEC 62898-3	2020	Microgrids—Part 3: Protection and dynamic control.	AC electrical systems with loads and DER connected at LV or MV.
Aus /NZ	AS 4777-1	2016	Grid connection of energy systems via inverters Part 1: Installation requirements.	Inverters ≤200 kVA at low voltage.
Aus /NZ	AS 4777-2	2015	Grid connection of energy systems via inverters Part 2: Installation requirements.	Inverters at low voltage.
Germany	VDE-AR-N 4105	2011	Power generation systems connected to the low-voltage distribution network. Technical minimum requirements for the connection to, and parallel operation with, low-voltage distribution networks.	Power generation systems ≤100 kVA connected to low voltage.
Italy	CEI 0-21	2019	Reference technical rules for the connection of active and passive users to the LV electrical utilities.	Active and Passive Users at distribution systems.
Spain	UNE 206007-1	2013	Requirements for connecting to the power system. Part 1: Grid-connected inverters.	Inverters connected to public distribution network.
UK	EREC G98	2019	Requirements for the connection of Fully Type Tested Micro-generators (up to and including 16 A per phase) in parallel with public Low Voltage Distribution Networks on or after 27 April 2019.	Micro-generators up to and including 16A per phase.

6 DER INTEGRATION – TECHNICAL DEFINITIONS & CHALLENGES

6.3 OVERVIEW OF DER AND EV INTERCONNECTION STANDARDS continued

Various standards exist for the 'group management' of DER devices within a DERMS, in addition to the smart inverter protocols listed above, including Open ADR [41], IEC 61850. As introduced earlier, California has mandated IEEE 2030.5 as the default application protocol (transport over the internet through TCP/IP) for distribution network utility communication with individual DER devices, facility EMSs (Energy Management Systems), and aggregator DERMS. Details of the IEEE 2030.5 profile are defined in the California IEEE 2030.5 Implementation Guide. Other Application-Level protocols may be used by mutual agreement, including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850.

The IEEE 2030.11-2021 [42] standard looks at the functional specification requirements for DERMS systems. It focuses on the requirement for an operational and effective deployment for many DERs, which include sources of power and demand response, to enable the provision of flexibility and grid services. The aggregation function, as well as the functions required to enable grid services, are provided by DERMS.

In Australia, AEMO are drafting AS 4755 [43] as a DER Standard for Demand Response. AEMO have identified improvements to smart appliance demand response capabilities as a key requirement to assist in the reduction of system risk arising from these challenges. Demand response refers to the ability for DER and appliances (including 'smart' pool pumps, electric hot water storage heaters, air conditioners, batteries, and electric vehicle supply equipment) to respond to remote communications that increase or decrease the amount of load on the power system. In some instances, the ability to stop using power from the grid, or start using it, is also built into the appliance.

6.4 IEEE 1547 STANDARD FOR DER INTERCONNECTION

The IEEE 1547 family[12] of standards provides the global foundation of rules for interconnecting DERs to the distribution grid, see Figure 12. This standard provides requirements relevant to the performance, operation, testing, safety, and maintenance of interconnected systems. It also includes specific details on interoperability guidelines between DERs and the electrical network.

The Internet of Things (IoT) leverages sensors and internet-based communication for connectivity between devices[44]. This can provide interoperability pathways for active management of DER enabling a range of services through process intelligence informed by the real time monitoring of devices. Current challenges associated with IoT solutions include reliable end-to-end architectural design given the range of diverse technologies, data, and systems integration between IoT devices other DER devices. IoT standardisation including information models and communication protocols, as well as cyber security and data privacy are all currently being developed for future rollout.

The latest IEEE 1547 standard (2018)[11] includes the following technical specification requirements for DER network participants, see Table 9.

FIGURE 12 **IEEE 1547-2018** [11]
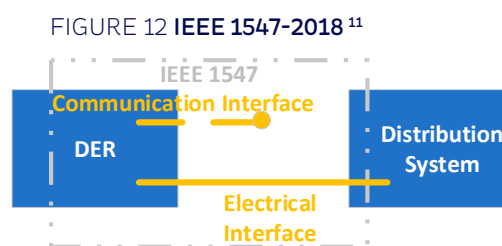
6   DER INTEGRATION - TECHNICAL DEFINITIONS & CHALLENGES

TABLE 9   IEEE 1547-2018[12]

CATEGORY	DESCRIPTION
Reactive power support	The reactive power capability will primarily be leveraged to support the local voltage conditions on the utility system, and it must be carefully coordinated with the utility while meeting all jurisdictional rules.
Ride-through requirements	Mandatory voltage and frequency disturbance ride-through capabilities that vary depending on the type of technology.
Bulk system support	Primary frequency-response functionality to allow DERs to help mitigate frequency disturbances on the bulk power system, like bulk power generator requirements.
Protection coordination	Clarification for the need to coordinate DERs with feeder reclosing to prevent reclosing into unintentional island conditions or phase differences.
Power quality	Power-quality requirements that address the smart inverters associated with DERs.
Interoperability requirements	Interoperability requirements that will allow DERs to be integrated into distribution systems with automated controls and updated switching and reclosing schemes.
Testing	Testing that will characterise short-circuit current characteristics of inverters and other technologies.
Function prioritisation	Capability to specify the priority of various DER functions.
Open phases	Capability to detect open-phase conditions for DER systems.
Default and adjustability	DER control and trip settings with both default settings and a wide range of adjustability for many technologies.
Anti-island prevention	The detection and trip time for a minimum of 2 seconds.
Communication standards	Communications interfaces with a standardised, non-proprietary design.

DER location and evolving grid conditions may require continued change of DER parameter values. IEEE 1547 clearly states that certain parameters need to be adjustable within a specified range. The system operator may request other parameter value changes on an on-going basis; based on power system study updates or new network characteristics.

DER communication equipment sits at each DER site, connecting, integrating, and bringing DERs onto the system operator control system. DER gateways can be a practical necessity, at a minimum providing the network-interface (e.g., modem, radio, etc.) needed to connect into the communication system being used to connect to an external network.

IEEE 1547 highlights the need for utilities to choose different communication systems and standards for different needs and to upgrade communication systems over time to keep in line with current technologies and security requirements.

# 6 DER INTEGRATION – TECHNICAL DEFINITIONS & CHALLENGES

6.5 IEC 61850 AND IEEE 2030.5: 2 KEY COMMUNICATION STANDARDS FOR DER INTEGRATION

IEC 61850 and DNP3 have been the globally preferred protocols for communicating with large-scale DER. IEEE 2030.5 is an IP-based application protocol for smart metering and automation of demand/response, and load control in local or home area networks. It can be used in residential and commercial building settings to connect and manage devices using the Smart Grid. The IEEE 2030.5 standard (formerly known as Smart Energy Profile 2 or SEP 2) is being adopted in California as the default communications protocol for residential DER integration applications.

IEEE 2030.5 currently supports smart inverter functions such as the ability to limit real power output, set Volt-Watt parameters, set fixed power factor, update VAr curves, and monitor DER status, as well as the capability to manage groups of inverters such as those in a targeted feeder geography.

The IEEE 2030.5 standard is being adopted as a communication standard for utility communication to residential DER such as solar, storage and EV systems [45]. The transport layer is expected to be TCP/IP between the utility and the DER site, see Figure 13 from the Sandia National Laboratory (US Department of Energy). The application layer can be either IEEE 2030.5, IEEE 1815 or Modbus, with information models aligning to SunSpec, CSIP, DNP3. This illustrative architecture is expected to be a critical component of interoperability as new DER resources are better integrated into secure grid operations.[46, 47]

FIGURE 13
ILLUSTRATIVE DER COMMUNICATION ARCHITECTURE44 (SANDIA NATIONAL LABORATORY, US DEPARTMENT OF ENERGY)

7
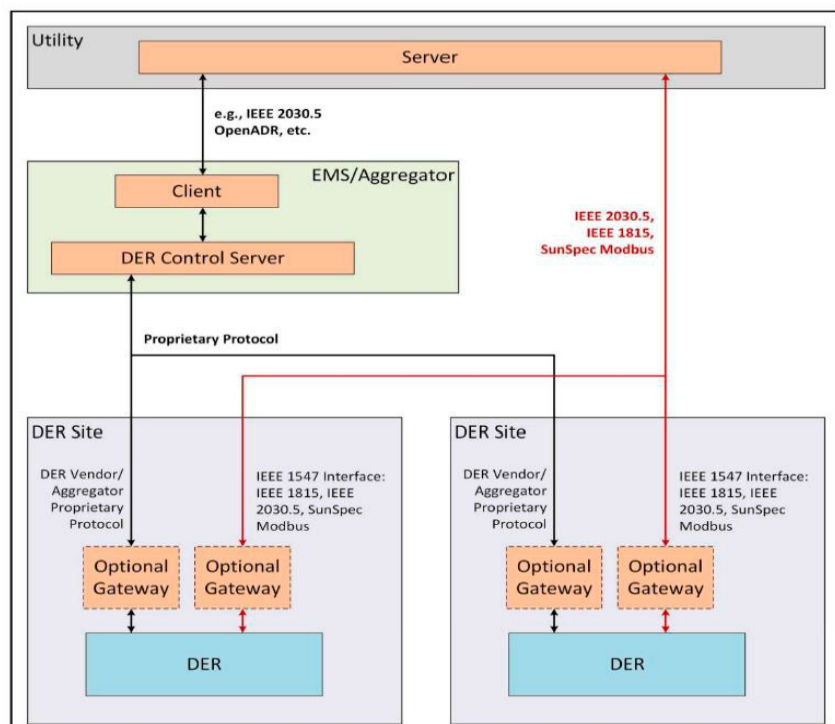
ESB Networks – DER Interconnection Data & Signal Technical Requirements

This section of the document provides ESB Networks technical requirements for the interconnection of DERs to dispatch active and reactive power services.

It is centrally a guidance overview to all the parties (directly connected customer/aggregator) involved in designing and integrating the DER into the ESB Networks' distribution system.

This section specifies technical requirements including both functional and non-functional requirements. It also clarifies responsibilities and roles where relevant as it refers to specific industry standards or best practice.

ESB Networks will require compliance with EU RfG Network Code [33], EN 50549 [36] and IEEE 1547-2018 [11] (or newer versions of same as they are released) for grid connected smart inverter based DERs.

In addition, a high-level anticipated guidance of DER compliance and commissioning test measures are also to be included in this section.

7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

7.1 FUNCTIONAL AND NON-FUNCTIONAL REQUIREMENTS FOR DER INTERCONNECTION

The scope of this document covers the requirements that are associated with the interface involving data and signal exchange between a DER customer/aggregator and ESB Networks.

The followings topics will not be covered in this document:

• Data exchange for market availability and market management systems.

• Protection standards and network code changes for DER integration.

The requirements for these topics will be covered by future guidance to be published by ESB Networks.

For a detailed list of proposed data and signals exchange between ESB Networks and the DER please refer to the DER interface signals and data guidance table– in Section 6.3 and Appendix A of this document.

7.1.1 FUNCTIONAL REQUIREMENTS

The following functional requirements will be required by the DER customer/aggregator to commission the DER for the service dispatch function. The technical detail underlying these operation modes has been presented earlier in Section 5.2.

The DER inverter must be capable of operating in Power Factor (PF) mode maintaining PF within pre-defined limits.

The DER inverter must also be able to change its mode of operation from PF to voltage control once receiving a target voltage setpoint.

ESB Networks may instruct the DER to enable or disable a mode of operation. The DER inverter must be able to change its mode of operation from PF to voltage control once receiving a target voltage setpoint. Depending on the services in which the DER is participating, the DER control system shall act on the relevant signals.

These modes shall include:

• Voltage and active power control (Volt/Watt)

• Voltage and reactive power control (Volt/Var)

• Power factor mode

7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

7.1.1.1 VOLTAGE AND ACTIVE POWER CONTROL (VOLT/WATT)

Where DER participates in the active power service, ESB Networks must have control over the real power import and export of the DER.

ESB Networks may issue the following signals to the DER:

1. Active power setpoint.
2. Upper active power limit setpoint.
3. Lower active power limit setpoint.

The DER inverter shall accept a setpoint signal which controls the active power output of the DER over its full rated range (precise control within its declared capability and not simply on/off). The setpoints will be issued within the DER plant limits. The active power setpoint issued to DER will not alter its normal operation.

Where a DER participates in the reactive power service, ESB Networks must have control over the voltage setpoint of the DER to adjust the generator terminal voltage. To this effect, ESB Networks may issue the following setpoint signal to the DER:

1. Voltage setpoint.

7.1.1.2 VOLTAGE AND REACTIVE POWER CONTROL (VOLT/VAR)

Where a DER participates in the voltage control service, changing reactive power output in response to voltage fluctuations, ESB Networks must have the ability to set the reactive power import and export limits of the DER onto the network. To this effect, ESB Networks may issue the following signals to the DER:

1. Upper reactive power limit setpoint.
2. Lower reactive power limit setpoint.

7.1.1.3 POWER FACTOR MODE

The DER may be required to adjust its power factor based on ESB Networks' signal. To this effect, ESB Networks may issue the following setpoint signals to the DER:

1. Power Factor leading limit setpoint.
2. Power Factor lagging limit setpoint.

7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

7.1.2 NON-FUNCTIONAL REQUIREMENTS

The following non-functional requirements are anticipated by the DER customer/aggregator to connect the DER to provide power service dispatch:

1. System availability.
2. Communication Link from DER to ESB Networks.
3. ESB Networks Control Signals to DER.
4. Cybersecurity Requirements from DER to ESB Networks.

7.1.2.1 SYSTEM AVAILABILITY

ESB Networks recommends that the customer has a DER with the highest level of system availability (99.99%) so that impact on service dispatch and post-dispatch can be minimised.

7.1.2.2 COMMUNICATION LINK FROM DER TO ESB NETWORKS

The customer/aggregator is responsible for the provision and maintenance of all communication links from the customers/aggregators DER inverter to ESB Network's communications interface, to ensure the reliability of this communication link as the DER service dispatch process may be impacted whenever this link fails.

The customer and/or aggregator will be responsible to ensure their solution can support this requirement before procuring their equipment.

ESB Networks will recommend the customer/aggregator to adopt the highest standards as they are released to ensure the reliability of this communication link (a minimum of 99.99% availability) as the DER service dispatch process may be impacted whenever this link fails.

7.1.2.3 ESB NETWORKS CONTROL AND VISIBILITY SIGNALS TO DER

ESB Networks equipment will require the sending of digital communication signals to the customer/aggregator DER to provide network condition visibility to the system operator.

7.1.2.4 CYBERSECURITY REQUIREMENTS FROM DER TO ESB NETWORKS

The customer/aggregator shall design their network in compliance with the most rigorous industry standards and guidelines. ESB Networks maintains multiple layers of security and controls within its infrastructure to protect its core systems [45] [46] .The DER customer/aggregator shall comply with all the technical and cyber security requirements as specified by ESB Networks.

The cybersecurity requirements will include (ESB Networks cyber security requirements will grow substantially over the coming years as standards are updated, therefore this list is not exhaustive):

1. Ensuring monitoring and communications devices are physically secure.
2. Protection and control from the network systems (firewalls).
3. Privilege settings and password protection.
4. Limiting access to only that which is required to monitor the generating unit.

7   ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

7.2   ESB NETWORKS SIGNAL & DATA EXCHANGE ARCHITECTURE

A DER can interface to ESB Networks DMS infrastructure via two methods: directly connected customers and/or using a 3rd party aggregator to connect DER customers. Figure 14 and Figure 15 provide the indicative ESB Networks' overview SGAM architecture for the interconnection of DERs to dispatch active and reactive power services.

IEEE 1547 requires DER devices to be compatible with instructions from a communication interface in at least one of three specified protocols able to support common smart inverter function (IEEE 1815/DNP3[50], IEEE 2030.5 and SunSpec Modbus[19]). During development of IEEE 1547, it was acknowledged that multiple options could leave both utilities and manufacturers uncertain about which interface to use and what to expect. The optionality was driven by differences in stakeholder preferences and different needs for various DER sizes. Moving forward, this needs to be considered in the context of a potential market and system characteristics.

The provided SGAM architecture provides the communication and information layer for Volt/Watt active (P) / Volt/VAR reactive power (Q) control of DER units.

The communications protocol, Figure 14, for the interface between ESB Networks' Message Bus DER Gateway and directly connected customers shall be IEEE 2030.5 protocol (transport over the internet through secure TCP/IP) which provides a secure communication pathway for smart inverter interfaced domestic DER. Other Application-Level protocols may also be used by mutual agreement, including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850.

The communications interface between ESB Networks HES (Head End System) and the Aggregator Control Centre shall be ICCP or similar secure protocol. It is anticipated that the interface between Aggregator Control Centre Gateway to the aggregated customers shall be IEEE 2030.5[19] protocol (transport over the internet through secure TCP/IP) which provides a secure communication pathway for smart inverter interfaced customer's DERs. Other Application-Level protocols may also be used by mutual agreement between the aggregator and their customers, including IEEE 1815/DNP3[50] for SCADA real-time monitoring and control and IEC 61850.

7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

FIGURE 14 **DER COMMUNICATION LAYER ARCHITECTURE**
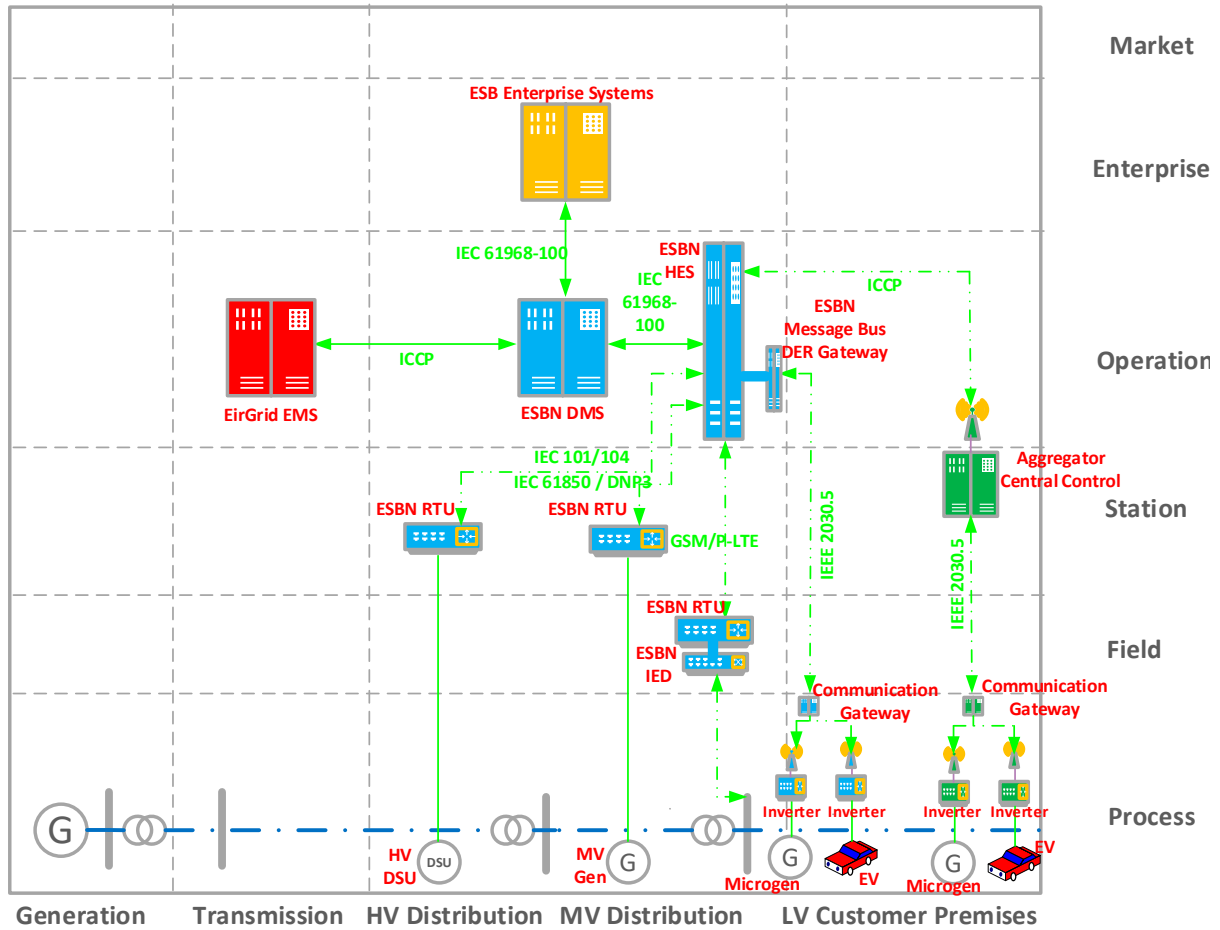
7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

Figure 15 provides the sequential flow of the information layer:

1 MV/LV voltage is monitored by the ESB Networks DMS.

2 EirGrid may request, or ESB Networks may require, a change to voltage setpoints to control active (P)/reactive power(Q) on the network.

3 The ESB Networks DMS will run a power flow assessment to calculate possible DER geographic availability/impact on the network.

4 The ESB Networks DMS will then determine the required voltage setpoints to control active (P)/reactive power(Q) service.

5 Prior to any changes to voltage setpoints, for audit purposes, an acknowledgement is sent to the ESB Enterprise Systems of the changes to be enacted.

6 The ESB Networks DMS then requests, via the ESB Networks HES active/reactive power setpoints, to either DSO directly connected customers and/or to the Aggregator Central Control.

7 The ESB Networks DMS monitors the system to ensure the action has been enacted.

FIGURE 15 **DER INFORMATION LAYER ARCHITECTURE**
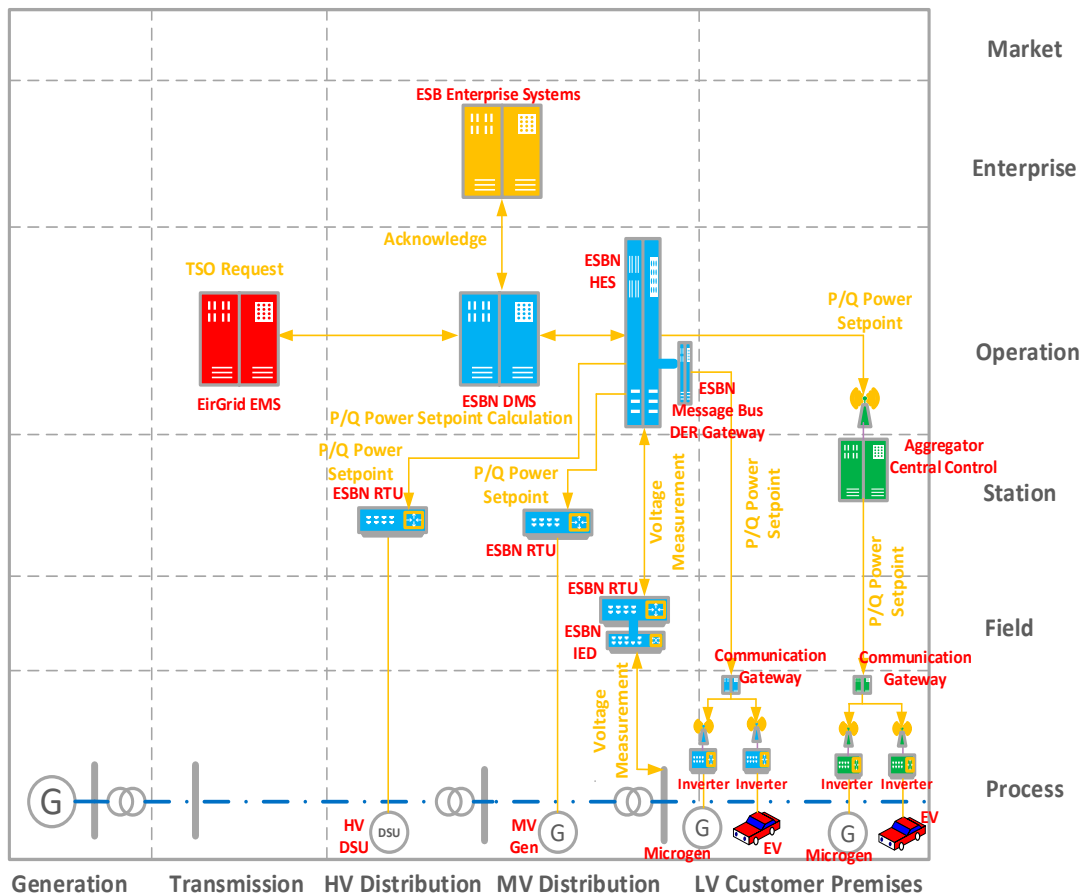
7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

7.3 ESB NETWORKS TO THE CUSTOMER/AGGREGATOR DER – RESPONSIBILITY MATRIX

The DER customer/aggregator is responsible for all the equipment within its domain. Separate responsibilities for both parties are clearly delineated in Table 10.

		TABLE 10 RESPONSIBILITY MATRIX - ESB NETWORKS AND CUSTOMER/AGGREGATOR	
NO.	**COMPONENT**	**ESB NETWORKS**	**DER CUSTOMER / AGGREGATOR**
1	ESB Networks IED	Responsible for supplying, installing, commissioning, and maintaining the equipment.	Not Applicable.
2	DER Inverter	Responsible for specifying the interface requirements between the DER Gateway and the DER control system.	Customer and aggregator responsible for supplying, installing, commissioning, and maintaining the equipment.
3	Aggregator Central Control	Not Applicable.	Aggregator responsible for supplying, installing, commissioning, and maintaining the equipment.
4	Communication link between ESB Networks equipment and the DER	Responsible for specifying the compatible protocols for both DER control system and ESB Networks.	Customer and aggregator responsible for configuring and maintaining the communication link.
5	Cybersecurity	Responsible for designing and maintaining cyber security of its own equipment to the highest international standards.[48][49]	Customer and aggregator responsible to design and maintain cyber security of its own equipment to the highest international standards. [48][49]

7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

7.4 ESB NETWORKS SIGNAL & DATA EXCHANGE LIST TO DER

Table 11 provides the primary list of data and signals requirements from ESB Networks to the DER customer/ aggregator.

A complete comprehensive table of all bidirectional data and signals requirements is provided in Appendix A.

NO.	DATA EXCHANGE BETWEEN ESB NETWORKS AND CUSTOMER/ AGG DER	SOURCE	DESTINATION	DESCRIPTION
	TABLE 11 ESB NETWORKS SIGNAL & DATA EXCHANGE LIST TO DER			
1	Active Power Upper Limit	ESB Networks Operational Systems	DER Cust/ Agg	Maximum (kW) limit - To control output active power of the DER to maintain within the appropriate limit.
2	Active Power Lower Limit	ESB Networks Operational Systems	DER Cust/ Agg	Minimum (kW) limit - To control output active power of the DER to maintain within the appropriate limit.
3	Reactive Power Upper Limit	ESB Networks Operational Systems	DER Cust/ Agg	Maximum (kVAr) limit - To control output reactive power of the DER to maintain within the appropriate limit.
4	Reactive Power Lower Limit	ESB Networks Operational Systems	DER Cust/ Agg	Minimum (kVAr) limit - To control output reactive power of the DER to maintain within the appropriate limit.
5	Voltage Upper Limit	ESB Networks Operational Systems	DER Cust/ Agg	Maximum Voltage limit - To control output voltage of the DER to maintain within the appropriate limit.
6	Power Factor Upper limit (Lagging)	ESB Networks Operational Systems	DER Cust/ Agg	Power factor upper limit which the DER Control system must comply with the limits received from ESB Networks.
7	Power Factor lower limit (Leading)	ESB Networks Operational Systems	DER Cust/ Agg	Power factor upper limit which the DER Control system must comply with the limits received from ESB Networks.
8	Setpoint Active Power	ESB Networks Operational Systems	DER Cust/ Agg	This is the target active power value requested to the DER which provides active power service, to control the active power output of the DER to maintain an appropriate export.
9	Setpoint Voltage	ESB Networks Operational Systems	DER Cust/ Agg	This is the target voltage value requested to the DER which provides reactive power service.

7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

7.5.1.2 DER SPEED OF RESPONSE TO REAL AND REACTIVE POWER TEST

These tests will examine the DER's speed of response capability to achieving real and reactive power service instructions issued to DER's Inverter Control System.

Figure 17 illustrates measuring how long it takes for DER to achieve a new real power (MW) set point at its point of connection.

FIGURE 17 **SPEED OF RESPONSE TO REAL POWER SET POINT INSTRUCTION**
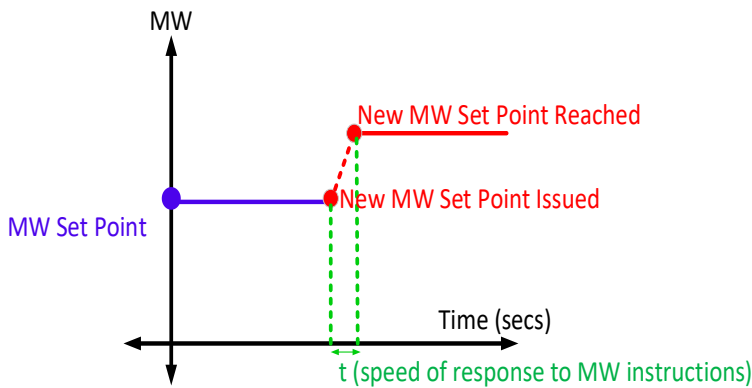
Figure 18 illustrates how long it takes DER to achieve a final reactive power import/export at its point of connection following the issue of a voltage set point instruction.

FIGURE 18 **SPEED OF RESPONSE TO REACTIVE POWER SET POINT INSTRUCTION**
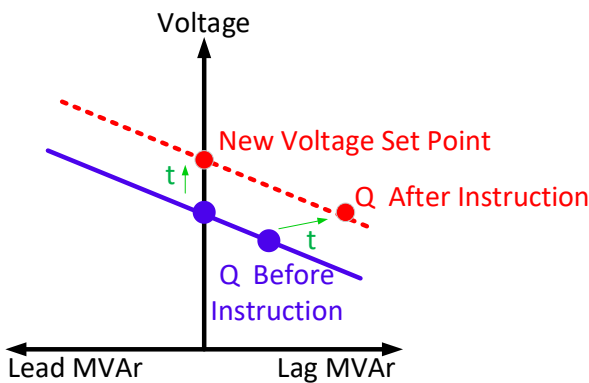
7.5.2 INDICATIVE ON-SITE VERIFICATION

ESB Networks representatives/registered installers may go to the site of the installed DER customer/aggregator to verify full compliance with the functional and non-functional requirements as set out in this document (Sections 6.1 to 6.4). Given the early stages of this technology implementation, this process will be clarified in time.

7 ESB NETWORKS – DER INTERCONNECTION DATA & SIGNAL TECHNICAL REQUIREMENTS

7.6 POTENTIAL TECHNICAL REQUIREMENTS OVERVIEW FOR DER INTEGRATION

Table 12 provides the overview potential set of requirements by ESB Networks to the DER customer/ aggregator for network service participation. This consultation is looking to add to this list for additional requirements that will be considered for inclusion as requirements going forward.

TABLE 12	ESB NETWORKS CHECK LIST CONDITIONS FOR DER PARTICIPATION	
NO.	**ESB NETWORKS CONDITIONS FOR DER PARTICIPATION**	**YES/NO**
1	The DER shall be connected to the network asset being supported. ESB Networks will verify that the electrical connection is suitable.	
2	Generators and storage looking to export to the network shall have a long-term parallel connection and be compliant with the requirements of EU RfG Network Code, EN 50549-1 and IEEE 1547-2018 and all relevant DER communications standards.	
3	The DER shall have system capability to submit service availability.	
4	Reactive Power Service - DER shall be capable of operating in voltage droop control to automatically deliver changes in reactive power in response to system voltage changes.	
5	Reactive Power Service - DER shall be able to change the voltage set-point of its voltage droop control.	
6	Active Power Service - DER shall be able to change the voltage set-point of its voltage droop control.	
7	Active Power Service - The DER shall be able to deliver and manage, upon ESB Networks' request, a net change in the import or a change in the export, as seen by the distribution network.	
8	Active Power Service - The DER shall be able to declare a minimum running time. This is yet to be specifically defined.	
9	Provide Full Site-Specific Details – MPRN, MIC, MEC, monitoring and control capability & operational response capability.	
10	Provide full details of Technology Specific DER Characteristics – i.e. Storage Capacity (MWh) for Battery.	

8

Appendix A

8 APPENDIX A – DATA EXCHANGE SIGNAL LIST

This appendix provides a illustrative technical list of the data and signal exchange requirements between ESB Networks and the Customer and/or DER aggregator. ESB Networks welcomes your feedback and comment on this during the consultation.

NO.	DATA EXCHANGE BETWEEN ESB NETWORKS AND CUSTOMER/ AGG DER	SOURCE	DESTINATION	DESCRIPTION
1	Active Power Upper Limit	ESB Networks Operational Systems	DER	Maximum (kW) limit - To control output active power of the DER to maintain within the appropriate limit.
2	Active Power Lower Limit	ESB Networks Operational Systems	DER	Minimum (kW) limit – To control output active power of the DER to maintain within the appropriate limit.
3	Reactive Power Upper Limit	ESB Networks Operational Systems	DER	Maximum (kVAr) limit – To control output reactive power of the DER to maintain within the appropriate statutory limit.
4	Reactive Power Lower Limit	ESB Networks Operational Systems	DER	Minimum kVAr limit; To control output reactive power of the DER to maintain within the appropriate limit.
5	Voltage Upper Limit	ESB Networks Operational Systems	DER	Maximum Voltage limit: To control output voltage of the DER to maintain within the appropriate limit.
6	Power Factor Upper limit (Lagging)	ESB Networks Operational Systems	DER	Power factor upper limit which the DER Control system must comply with the limits received from ESB Networks.
7	Power Factor lower limit (Leading)	ESB Networks Operational Systems	DER	Power factor lower limit which the DER Control system must comply with the limits received from ESB Networks.
8	Setpoint Active Power	ESB Networks Operational Systems	DER	This is the target active power value requested to the DER which provides active power service, to control the active power output of the DER to maintain an appropriate export.
9	Setpoint Voltage	ESB Networks Operational Systems	DER	This is the target voltage value requested to the DER which provides reactive power service. .
10	DER Link Counter	ESB Networks Operational Systems	DER	This signal is used by DER to monitor communications health to ESB Networks.
11	V Service Enable	ESB Networks Operational Systems	DER	This is an instruction to DER to enable V mode. DER should go to V mode (if they are in PF mode as default) and provide reactive power services by responding appropriately to the receiving limits and voltage setpoint.
12	P Service Enable	ESB Networks Operational Systems	DER	This is an instruction to DER to instruct them to revert to their normal configuration mode and settings.
13	Disable Mode Enable	ESB Networks Operational Systems	DER	This is an instruction to DER to instruct them to revert to their normal standby mode.

8   APPENDIX A – DATA EXCHANGE SIGNAL LIST

NO.	DATA EXCHANGE BETWEEN ESB NETWORKS AND CUSTOMER/ AGG DER	SOURCE	DESTINATION	DESCRIPTION
14	Limit breach	ESB Networks Operational Systems	DER	This is a notification signal for DER informing them that one or more of the limits has breached".
15	Failsafe Action	ESB Networks Operational Systems	DER	This is an alarm/instruction for failsafe actions carried out by ESB Networks, should the DER fail to provide an output which respects the limit. Failsafe actions will also be triggered due to any non-compliancy status or any risk for the network.
16	Decouple Alarm	ESB Networks Operational Systems	DER	This is a notification signal to inform DER that it has lost its communication with ESB Networks Operational Systems due to lack of receiving acknowledgment or response from DER. It is assumed that DER operates under safety condition by reverting to its original setting mode.
17	Readback Active Power Upper Limit	ESB Networks Operational Systems	DER	This is the feedback of the received "Active Power Upper Limit" (signal 1 here) by DER control system ESB Networks Operational Systems confirming acknowledgement of the action. This is required to check integrity of the DER control system and the comms link between ESB Networks RTU and DER.
18	Readback Active Power Lower Limit	DER	ESB Networks Operational Systems	This is the Readback of the received "Active Power Lower Limit" by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This is required to check integrity of the DER control system and the comms link between ESB Networks RTU and DER.
19	Readback Voltage Upper Limit	DER	ESB Networks Operational Systems	This is the Readback of the received "Voltage Upper Limit" by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This is required to check integrity of the DER control system and the comms link between ESB Networks Operational Systems and DER.
20	Readback Voltage Lower Limit	DER	ESB Networks Operational Systems	This is the Readback of the received "Voltage Lower Limit" by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This is required to check integrity of the DER control system and the comms link between ESB Networks Operational Systems and DER.

8   APPENDIX A – DATA EXCHANGE SIGNAL LIST

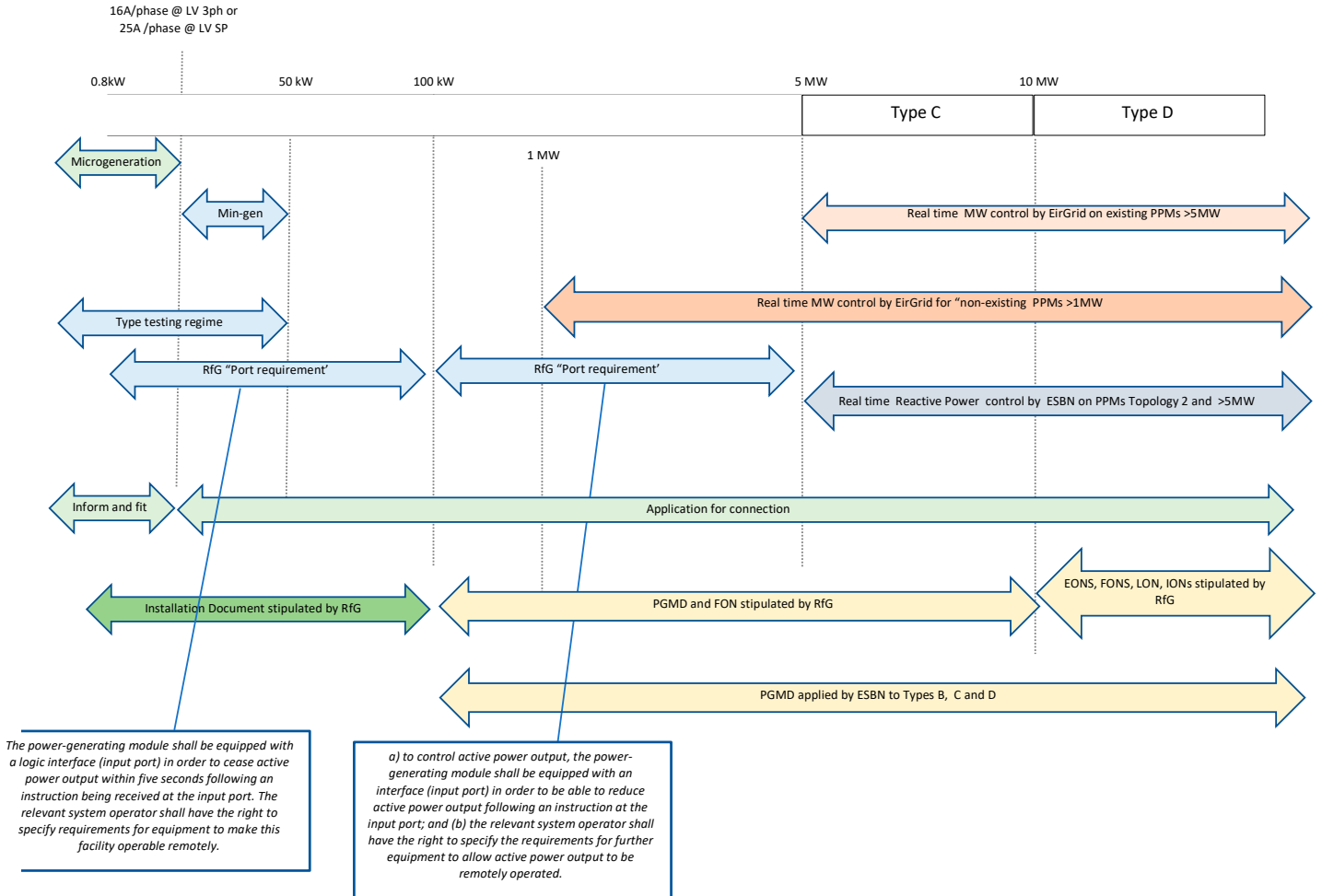| NO.	DATA EXCHANGE BETWEEN ESB NETWORKS AND CUSTOMER/ AGG DER	SOURCE	DESTINATION	DESCRIPTION
21	Readback Voltage Upper Limit	DER	ESB Networks Operational Systems	This is the Readback of the received "Reactive Power Upper Limit" by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This is required to check integrity of the DER control system and the comms link between ESB Networks Operational Systems and DER.
22	Readback Voltage Lower Limit	DER	ESB Networks Operational Systems	This is the Readback of the received "Reactive Power Lower Limit" by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This is required to check integrity of the DER control system and the comms link between ESB Networks Operational Systems and DER.
23	Readback Active power setpoint	DER	ESB Networks Operational Systems	This is the Readback of the received "Active Power setpoint" by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This is required to check integrity of the DER control system and the comms link between ESB Networks Operational Systems and DER.
24	Readback Voltage setpoint	DER	ESB Networks Operational Systems	This is the Readback of the received "voltage setpoint" by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This is required to check integrity of the DER control system and the comms link between ESB Networks Operational Systems and DER.
25	MW Capacity in Service	DER	ESB Networks Operational Systems	DER Controller's indication of percentage of MW capacity in service, relative to total plant rating at commissioning.
26	Measured Customer Voltage	DER	ESB Networks Operational Systems	Customer's own voltage measurement at generator terminal, for comparison with ESB Networks measurement at point of connection.
27	Measured Customer Active Power	DER	ESB Networks Operational Systems	Customer's own active power measurement at generator terminal, for comparison with ESB Networks measurement at point of connection.
28	Measured Customer Reactive Power	DER	ESB Networks Operational Systems	Customer's own reactive power measurement at generator terminal, for comparison with ESB Networks measurement at point of connection.

8 APPENDIX A – DATA EXCHANGE SIGNAL LIST

NO.	DATA EXCHANGE BETWEEN ESB NETWORKS AND CUSTOMER/ AGG DER	SOURCE	DESTINATION	DESCRIPTION
29	Measured Customer Power factor	DER	ESB Networks Operational Systems	Customer's own power factor measurement at generator terminal, for comparison with ESB Networks measurement at point of connection.
30	Readback failsafe	DER	ESB Networks Operational Systems	This is the feedback of the received "Failsafe" by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This confirmation will be used to detect abnormal behaviour between ESB Networks Operational Systems and DER.
31	Readback V Service Enable	DER	ESB Networks Operational Systems	This is the feedback (mirror) of the received V services enabled by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This confirmation will be used to detect abnormal behaviour between ESB Networks Operational Systems and DER.
32	Readback P Service Enable	DER	ESB Networks Operational Systems	This is the feedback (mirror) of the received P services enabled by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This confirmation will be used to detect abnormal behaviour between ESB Networks Operational Systems and DER.
33	Readback Contractual Mode Enable	DER	ESB Networks Operational Systems	This is the feedback (mirror) of the received Contractual mode enabled by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This confirmation will be used to detect abnormal behaviour between ESB Networks Operational Systems and DER.
34	Readback Disable Mode Enable	DER	ESB Networks Operational Systems	This is the feedback (mirror) of the received Disable enabled by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This confirmation will be used to detect abnormal behaviour between ESB Networks Operational Systems and DER.
35	DER Services	DER	ESB Networks Operational Systems	This is the feedback (mirror) of the received "Service Enable" signal by DER control system to ESB Networks Operational Systems confirming acknowledgement of the action. This confirmation will be used to detect abnormal behaviour between ESB Networks Operational Systems and DER.

9

Appendix B

9   APPENDIX B – TYPE A TO TYPE D GENERATORS IRELAND

This Figure presents the grid connection characteristics for Type A to Type D generators.

16A/phase @ LV 3ph or
25A /phase @ LV SP

| 0.8kW | 50 kW | 100 kW | 5 MW | 10 MW |

| Type C | Type D |

Microgeneration

1 MW

Min-gen

Real time MW control by EirGrid on existing PPMs >5MW

Real time MW control by EirGrid for "non-existing PPMs >1MW

Type testing regime

RfG "Port requirement'   RfG "Port requirement'

Real time Reactive Power control by ESBN on PPMs Topology 2 and >5MW

Inform and fit   Application for connection

Installation Document stipulated by RfG   PGMD and FON stipulated by RfG   EONS, FONS, LON, IONs stipulated by RfG

PGMD applied by ESBN to Types B, C and D

The power-generating module shall be equipped with a logic interface (input port) in order to cease active power output within five seconds following an instruction being received at the input port. The relevant system operator shall have the right to specify requirements for equipment to make this facility operable remotely.

a) to control active power output, the power-generating module shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port; and (b) the relevant system operator shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.

NETWORKS   NATIONAL NETWORK, LOCAL CONNECTIONS PROGRAMME

10

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9   PURPA created a market for power from non-utility power producers. Before the act's enactment, only utilities could own and operate electric generating plants. PURPA required utilities to buy power from independent companies that could produce power via "qualifying facilities" (QFs) for less than what it would have cost for the utility to do so (i.e., the avoided cost). See: https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/other-regulatory-efforts/public

10   Electric Rule 21 formalised technical concerns into a predefined set of screens, offering a path to simplified connection. Electric Rule 21, initially instituted in 1982 and revised multiple times, is a tariff that describes the interconnection, operating, and metering requirements for distributed generation facilities to be connected to a utility's distribution system. See: http://www.cpuc.ca.gov/Rule21/

11   FERC's SGIP, defined processes of technical screening, the "fast track" concept, and types of studies including decision points in reviews. Its requirements are very similar to CA Rule 21. The FERC's standards include the SGIP, which contains the technical procedures that the small generator and utility must follow in the course of connecting the generator with the utility's lines, and a Small Generator Interconnection Agreement (SGIA), which contains the contractual provisions for the interconnection and spells out who pays for improvements to the utility's electric system (if needed to complete the interconnection).
     See: https:// www.ferc.gov/industries/electric/indus-act/gi/small-gen/sm-gen-procedures.pdf

12   IEEE 1547 is the master or lead standard in a series of IEEE standards, recommended practices, and guides related to DER interconnection. A large industry working group, with over 350 members, developed the original 2003 IEEE 1547 standard from 1999 to 2002; it was balloted and officially adopted by IEEE in 2003. See: https://standards.ieee.org/standard/1547-2003.html

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