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Recommendations for the deployment of DSO projects

SECOND EDITION

CurrENT

Enabling Network Technology throughout Europe

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Executive Summary

CurrENT recognises that one of the greatest challenges to developing the distribution network is the introduction of new technologies. This guide document provides a series of recommendations to Distribution System Operators to support the deployment of a range of mature, commercially available, innovative grid technologies. The application of any new technology requires consideration on how it is to be introduced into widespread operation. Existing technology introductory processes have been built around the prolonger timelines, high resources and very high capital expense of a project investment, meaning the risk of a costly stranded asset is high. The paper has utilised deployment issues from published sources and from CurrENT members' first-hand experience and considers the impact and interaction that these innovative grid technologies deployment will have with these. These issues include the limited bandwidth of DSO company skills and resources, standards and specifications, the challenges with the existing regulation and business models, along with the need for certainty in roles and responsibilities.
From these both general and technology-specific recommendations are made for both grid operators and national regulatory authorities for the more efficient, simplified deployment of a range of innovation grid technologies.

General recommendations include:

- That bespoke technical assurance work completed by a DSO is made available to peers to support their own technical assurance, through either CurrENT, or a relevant DSO association.
- To fully implement Action 7 of the Grids Action Plan, published by the European Commission, for an updating of the Distribution Technopedia to provide DSOs with a list of commercial ready technologies to minimize the effort in identifying and learning how to appraise (often new) alternative technologies. A transparent national or European Technopedia simplifies DSOs tasks of identifying technologies, sharing with stakeholders what they are and will consider, and sharing knowledge internally. CurrENT welcomes this step and is happy to collaborate with the EU DSO Entity in developing the Technopedia. Furthermore, CurrENT underscores the importance of this Technopedia having a clear focus on empowering DSOs to improve Europe's energy infrastructure by promoting smart grids, network efficiency, and innovative technologies.

Key recommendations for NRAs include:

- That regulatory bodies and policy makers, both nationally and European, put incentives in place to support the introduction of these technologies [1]. As mentioned in many places in this paper, the introduction of new technology can be highly effective for DSOs but initially requires time and resources be diverted to the task.
- CurrENT supports the concept of Anticipatory Investments and also that Anticipatory Investments apply to any and all investments that would address projected needs. This means that Anticipatory investments should start with fast build network efficiency projects that can be delivered in the next 1-3 years to address short term projected needs, and for which Innovative Grid Technologies on the distribution network are ideal.

Key recommendations for grid operators include:

- The Cost Benefit Analysis should be a net present value calculation with a true reflection of the costs and benefits. This should include the actual annual phased spending for building the project, and for fast deploying innovative grid technologies the added benefit from early construction, or delayed spending on constructing the project. The Cost Benefit Analysis should also consider the relative construction costs associated with one technology against another.
- The Cost Benefit Analysis shall be adapted to the national regulatory regime applicable to the Distribution System Operator.
- DSOs to work collaboratively with the grid optimized technology supplier[s] to ensure the technical assurance process can make best use of these materials to eliminate the need for repeat works and streamline the DSO commitment.
- It is advantageous not to wait to use grid-optimizing technologies but start the evaluation through to deployment process to avail of the benefits early. This paper has shown these benefits to the distribution network and its operators to be faster, lower cost, more flexible, beneficial and seamlessly integrated solutions.
- DSOs should only use functional specifications in tenders, permitting the widest inclusion of grid innovation technologies.
- The list of equivalent international technical l standards (where available) is recommended to be used.
- Wherever possible technical assurance should be minimized to only the areas of a new technology where the technology performance is truly essential. The suppliers have at their disposal past investigations (or selection and proof of international standards) compliance for other customers that are equivalent or often more onerous than the local conditions.
- The use of trial projects, or limited use first deployments, are eliminated in favour of first deployment[s] into full active use in the network. As DSOs who perform the recommended review of the impact will find the needs and benefits of introducing the technology far outweigh any risk of stranding assets.
- That the technologies in this paper are considered in combination. The suppliers of these technologies can offer guidance on the possible combinations to address individual cases or needs, and there are other published examples included in the references of this paper.
- That DSOs customize their due diligence innovation process based on factual and not perceived risk of each new technology. The grid-optimizing technologies in this paper actually all have a method of application that provides significant benefits that do not jeopardize the network security.
- That DSOs select from these known issues on their network and align these with the use cases presented in the paper to apply these technologies as alternatives.

Introduction

The scale of the problem facing Europe's energy grids is huge. According to a report by the International Energy Agency, to facilitate the energy transition a total of 80 million kilometres of grids must be added or refurbished by 2040, the equivalent of the entire existing global grid [1]. Acknowledging this issue, the European Commission implemented the Grids Action Plan in 2023. This Action Plan aims to accelerate the pace of grid development in Europe [2]. However, expanding grids in terms of kilometres added alone is not enough. As increased levels of renewable energy becomes available through decentralised generation; more control, grid visibility, and forecasting will be needed. Expanded levels of digitalisation in the grid will be needed to be able to manage a system with more variable generation and increased flexibility needs [3]. Facilitating this transition will require the huge levels of investment. Between 2025 and 2050 investment at the rate of €67 billion per year is needed in the EU27 member states + Norway in order to deliver a grid to meet growing electrification demands and enable a full-scale energy transition. Failure to do so in time could jeopardise Europe's energy security and mean missing out on the benefits of decarbonisation [4]. Innovative grid technologies, which can be deployed quickly and improve the efficiency of the existing grid, need to be considered as part of the solution. Innovative grid technologies can reduce the cost of increasing a grid's capacity and use less raw materials [5]. Innovation in distribution grids can reduce the investment required by around 18% to €55 billion annually when supported by right regulatory environment [4]. Over the long term, by investing in innovative grid technologies and deploying them at scale in parallel to conventional grid buildout, gross cost savings of €700 billion in conventional expansion costs can be achieved by 2040 [5].

This guide will look to highlight, through use cases, the proven benefits of innovative grid technologies, and address some of the challenges facing Distribution System Operators in deploying these innovative grid technologies. This guide document provides a series of recommendations to DSOs to support the deployment of a range of mature, commercially available, innovative grid technologies that optimise and maximise the use of the existing electricity grid, that are still not standardised for most companies.

Introducing new innovative technologies has been universally recognised by DSOs and their industry bodies [6] [7] [8] [9] as a necessity to meet the expected pace of development.

> *'The European Union's goals to reduce greenhouse gas emissions by increasing the share of renewables and to place customers at the centre of the energy system cannot be achieved without smart forward-looking electricity grids', E.DSO*

However, one of the greatest challenges to introducing these new technologies is the time of limited DSO expert resources to consider the specifics of the technology and its deployment.

CurrENT has recognised this barrier to the timely development of the innovative technologies that it represents and so has used its unique technology experts and experience of working with DSOs to assist and inform DSOs to reduce this burden.

At present, the deployment of many of the range of technologies in this guide is limited in the Distribution network. As a result, international standardisation through IEC, IEEE, ANSI, CIRED, CIGRE, ASTM and other international standardisation bodies has not been completed in some cases. In the absence of these, DSOs must encounter a more complex and involved process in specifying the equipment they want to meet their needs. CurrENT recognises this challenge, and its members have contributed their expert knowledge of the technologies and best practice in their application by DSOs in order to provide the recommendations in this guide.

In addition, many DSOs and their regulatory bodies will need to have a regulatory and procurement system in place to manage these innovative technologies through to deployment [10]. This guide provides recommendations on how this might be achieved based on past experience and the combined knowledge of the association. This covers initial analysis of procurement of technologies (typically term or bulk buying), and finally through to infield deployment.

This guide first seeks to identify the issues that have arisen in deployment of innovative distribution grid technologies, and then discusses a series of recommendations to address these issues. The recommendations are broken into two main categories, those that are generic to all technologies and recommendations that apply to specific technology[s]. The concluding recommendations have been broken down into separate recommendations for NRAs and recommendations that are specific to grid operators.

We have found that collaboration with our customers is at the core of successful delivery of projects that work as needed. We hope that this guide is illuminating and would welcome your feedback on what is missing or could be improved. CurrENT and its members would be pleased to offer further support in your needs. Please feel free to contact us at info@currenteurope.eu.

Known Deployment Issues for DSOs of Smart Grid technologies

Both through published sources and CurrENT members' first-hand experience working with DSOs the past years, a number of issues in understanding and the development of innovative grid technologies come up repeatedly [7]. These are briefly outlined and described below, and will help frame the content of this paper, which will try to address and provide direction or solutions on the management of these issues.

Clearly, as the distribution network and its users develop over time, new issues emerge, and it is CurrENT's intention for this paper to be a living document that will be periodically updated to capture new issues.

DSO company skills and resources

In a time of intense growth in the industry, with new customers, service providers and sectors opening up the pressure on existing internal resources and the ability to replace or bolster these has become acute for most DSOs. The ability of DSOs to maintain their core business and examine vitally needed new innovations is a major challenge. Growth in network replacements, extensions and/or adaptions in the future is predicted by all. Hence, this situation needs to be mitigated to enable decarbonisation and to meet targets and expectations.

Unlike many TSOs, DSOs often lack the engineering headcount to deliver the required CBA and engineering. To enable faster deployment, DSOs require easy access and well explained guides to new technologies, their benefits and applications, and from a verifiable or certified source.

In tandem, the support from experts in the field of these innovations from academia and suppliers will be an increasing necessity to quick test promising technologies, without extensive ranges of tests, or labour-intensive internal expert reviews.

Standards and Specifications

Traditionally DSOs have placed greater reliance on international general standards and specifications, than bespoke investigation and customisation. There are simply too many projects and maintenance activities at the DSO level to practically support the same approach and specialization as that used in the transmission network. This means that new technologies and innovations that may not be fully standardised or specified by the international bodies (IEC, IEEE, ANSI, BS, CIRED, CIGRE TB, etc.) present a real challenge, requiring more internal time and energy.

Like the DSOs, the standards bodies have a certain bandwidth, which by their own admission at present cannot keep pace with the speed of innovation. As cited by nearly every stakeholder in the industry, innovation must intensify and therefore this problem will continue to grow and must be resolved. Like the rest of the industry, there are insufficient experienced resources and too much interaction between existing and new standards to simply increase the size of the standards bodies in response.

To enable faster deployment, DSOs require an alternative equivalent method of providing the necessary type testing evidence of equipment suitability to DSOs for use. Acceptance of testing data, and reliance of peers' evaluations will be one mechanism. The support from experts in the field of these innovations from academia and suppliers will be another. Suppliers will undoubtedly be expected to provide equivalent standards and specifications, with reasonable justification and/or assurances to mitigate this issue.

Regulation and Business models

At present regulatory recovery of investments are based on the capital invested which is independent of the technology being used [11]. The perception that new technology performance presents a risk of the unknown means that often the known is selected over the unknown, resulting in inefficiency. This is compounded by the fact that deployment of a new technology may require the education of design, operation and fields teams into how to deploy and use.

Whilst some funds are made available from regulators and the EC to support new technology in favour of conventional approaches, it is often necessity because of a lack of an alternative that drives innovations and new technology use.

The level of uncertainty of future needs and predictions also make justification of a project more difficult with regulators, permitting authorities and wider society.

The use of new business models such as leasing, software as a service or public private financing, can offer some support but only where flexible regulatory processes and procedures can be supportive rather than obstructive.

Roles and Responsibilities

The deployment of technology as part of a wider project has traditionally been the responsibility of the DSO and their contractors. This has meant that a significant burden is placed on the DSO to be efficient in their plan of deployment, timely sourcing of material, commissioning tests, and provide sufficiently trained and skilled personnel for the work. To avoid simply repeating project deployments with known technology requires a step change in cost, reliability or scope of works.

Scope of works, costs and reliability can be greatly impacted with a change in roles and responsibilities, with suppliers either reducing the complexity of size of the scope of works and/or managing some deployment themselves. Alternatively, ancillary issues in the preparation and risk management of a project such as method statements being supplied with equipment can be a major labour saving.

One major issue is the commissioning of the deployment, where experienced resources are very limited, and inclusion of new technologies may be challenging. Traditionally, witness testing has been a common approach to manage this but can be resource expensive and complex. Limiting on-site commissioning would be desirable, as well as provision of supplier developed commissioning plans, ideally certifiable and globally reusable.

Technology that serves multiple purposes [12] [13] [14] can also be issued and a source of improvement, reducing the number of projects or components needed.

Innovative Grid Technologies: General Deployment Recommendations

CurrENT has reviewed and documented the specific deployment requirements for its members in the following chapters. These provide guidance and recommendations of the more specific requirements that DSO are likely to encounter in deploying the innovative grid technologies that its members provide.

DSO network studies

The DSO network study general recommendations make very little change to the normal network study principles used by DSOs to identify the distribution network development needs. In order to consider the viability and value of the use of most of the technologies presented in this report, network studies, use classical evaluation techniques. Normally a representative network and/or market model of the system operators is used, in conjunction with a proprietary software tool, to represent the current and future network.

Using this, the existing network can be assessed to see whether it complies with the planning and operational standards applied by the system operator and asset owner. A failing to meet these standards is a clearly identified need to consider mitigation. In addition, whilst these standards may be met, they may only be by using high-cost and often inefficient measures (e.g. high-cost generation or demand response, or demand disconnection). This might also trigger the need to do a mitigating development to reduce these costs.

These network studies usually start with market or load flow analysis, as these are simpler and quicker to do, capturing many of the needs that arise. However, more uncommon studies are becoming increasingly important as higher levels of renewables develop in the distribution system with fault level analysis, dynamic, power quality and EMT also being periodically required. These presently uncommon studies are primarily driven not by the technologies in this report, but by the condition of the network and hence the needs that arise. For example, power quality studies are becoming commonly needed due to the rising background harmonic levels of the network, as renewable energy use grows and the use of larger scale fossil fuel power plants that suppressed harmonics reduces. CurrENT recognizes the growing commonality of these studies and provides models to support these [15].

Once the need has been established, it is recommended to install the technology being considered (based on the network needs the technology is typically used to mitigate) into the same model and repeat the process. The viability and sizing of the solution to address the issue can then checked and confirmed, either resolving the uncompliant network standards issue or providing sufficient economic benefit to deploy. It is imperative to a good investment decision to consider a range of technologies that is diverse enough to identify most efficient solution, but that represents a commercially available and mature solution. CurrENT recommends that a technology toolbox either developed by the DSO independently or from a centralized recognized European DSO body (EUDSO, E.DSO, etc.) is used to perform this role. This approach is transparent and yet resource efficient to manage.

The specifics of how to conduct the network modelling before a solution, selecting and sizing a solution and how to confirm its viability as a solution, is explained in more detail in the relevant technology sections below.

Procurement and Functional Tender Specification

Tender specification is a complex and often challenging process with the need to be specific to ensure that a solution will work and to an acceptable standard, but not unwittingly reduce the ability of viable solution providers to be bid and therefore the competitive process.

The primary recommendation from CurrENT is to only use functional specifications in tenders. For example, that the components connected into a circuit and operating at line voltage must be able to withstand the operating voltage range of the circuit into which they are to be installed or will directly control or manage. However, care must be taken to not assume how a technology will work for instance a device controlling a circuit may not have any component at line voltage, therefore requiring components to be able to withstand the line voltage may unwittingly force some viable solutions to be non-compliant to the tender.

Tender specifications that present the environment into which the technology will be placed and must perform i.e. voltage range, current range, frequency range, etc. are less prone to unintentional bias. That being said, it is advisable to qualify the requirement, e.g. 'If the devices will be installed and operated at line voltage then they must be able to…'. Tender specifications that define the performance/physical characteristics such as availability of a solution, its construction, or the specifics of how it should operate are areas where commonly bias between technologies can more easily occur.

CurrENT recommends simple adjustments to tendering processes can benefit the process with no material time taken to manage tender specifications.

As a first adjustment, the inclusion of 'or equivalent' for performance/physical characteristics, provides suppliers with the opportunity to still submit to a tender where their offering would be unintentionally not able to meet the specification. This change places the emphasis on the supplier/contractor to explain to the DSO satisfaction how it can still perform as well or better than the tender specifies, with them doing most of the work.

The second adjustment would be the use of a Pre-Qualification Questionnaire (PQQ) or even a Request for Information (RFI) as a first step in a tender process. This first step allows the DSO tendering to collect responses to their specification, or information to inform it, as well as expressions of interest with either a RFI or PQQ. For example, the necessary information can be collected from potential suppliers that can be used to ensure no unintentional biases, e.g. suppliers own equipment specification sheets. In addition, this process can be used to draw together the international standards (e.g. IEC, ANSI, IEEE, ASTM) that innovative solution suppliers use to ensure that the functional capabilities have been tested, but that equipment standards that only apply to a subset of technologies are not required to be completed to meet the tender specification. Using the previous voltage example, specifying a standard that provides a supplier with internationally recognized method to prove equipment can operate at line voltages, only makes sense for solutions that will come in contact with the energized line.

It should be noted that the categories of the innovative grid technology in this report are very varied in the purpose, use and application, but share a common attribute of being essentially modular in their nature. This practically eliminates the risk of complete failure of a solution, and consequently means that network compliance to design standards is rarely jeopardized from a forced outage. It is recommended that this attribute is considered and reflected in tenders, for example when placing any expected availability of a solution in a tender.

It is expected that most tenders will be for term contracts, given the rapidity of DSO projects, as opposed to bespoke per unit specification. It is recommended that any type testing requirements be flexible as possible to the tenderer to provide the burden of proof of meeting requirements, with the use of 'or equivalent' to the greatest extent possible. The reason for this is twofold, firstly in many cases such term contracts will be for a range of unit sizes and/or capabilities, and secondarily suppliers have a wealth of past type testing to relevant standards or more onerous conditions to draw on, reducing time and cost to technical assurance for the customer. Given the rapidity of grid optimisation technology projects, it is often better to make a first deployment the type test.

Cost Benefit Analysis

The need for Cost Benefit Analysis will be governed by the regulatory regime applicable to the Distribution System Operator, which varies across Europe and therefore these recommendations must be considered in conjunction with the local regulatory requirements.

Cost Benefit Analysis can fall into two steps in the deployment of a project, the assessment of the need to do something and the selection between alternative solutions. The need to reinforce the network may not be required if the network is non-compliant with national planning standards, which can form this first step cost benefit analysis. CurrENT recommends a TCO approach, or at least the capture of total deployment project costs, rather than unit cost of a particular technology compared to legacy solutions.

For either step, it is recommended that Cost Benefit Analysis for distribution deployments use the industry standard of using net present value calculations [12]. Whether projects are sufficiently large as to justify bespoke Cost Benefit Analysis or are grouped it is recommended that the same benefits and costs be considered.

The main difference in the cost benefit analysis is the method that is used to provide the inputs to the net present value calculation. For a bespoke assessment, the specific network need is identified and the specific solution to that need. For grouped analysis, a once off Cost Benefit Analysis will be made assessing each typical network issue and then the range of solutions to meet that need. The best performing technology is then selected for each need and applied as a solution going forward whenever that network need arises.

The central general recommendation for all technologies with regard to cost benefit analysis is how the net present value calculation is formulated. A true reflection of the costs and benefits as they arise must be included.

In the worked example below the impact of including the added benefit of a fast construction timeline (1 year or less), avoiding the phased construction costs over years, is shown. In order to ensure that only the benefit of a quicker solution is demonstrated in this example two alternative technologies are considered with both the same capital and operation cost[1]. For this example, both technologies are assumed to have exactly the same cost of installation (1 PU) are compared. The first technology is an innovative grid technology for example one of the technologies in this report with a concept to installation speed of a year or less. The second technology is a conventional technology with a slower concept to installation time of 4 years, for example a phase shifting transformer. The operational cost (e.g. losses and maintenance) are taken to be identical at 1.5% of the capital cost.

To show the impact on this to the cost to the consumer, a Weighted Average Cost of Capital (WACC) of 4 - 8% has been applied to reflect the recovery cost of the borrowing by the asset owner to build the project. WACC is a common financial instrument used by regulators to set a reasonable rate of recovery for asset owners paid through network billing of consumers, but the actual rates vary across Europe. The period that WACC is paid on a project is typically across the life of the asset which could be 40-50 years typically, but often for a cost benefit analysis to be deemed positive a period of 20 years is used as in the example below.

Innovative Grid Technology Capital Cost:	1.0 PU
Innovative Grid Technology Operational Cost:	0.015 PU
Innovative Grid Technology Concept to install time:	1 year
Conventional Technology Capital Cost:	1.0 PU
Conventional Technology Operational Cost:	0.015 PU
Innovative Grid Technology Concept to install time:	4 year / 25% per annum
WACC Rate:	4 - 8%

Total Benefit[+] or Cost[-]	**Innovative Grid Technology**		**Conventional**	
	-0.91		**-1.01**	
	Cost	**Benefit**	**Cost**	**Benefit**
NPV	**0.91**	**0.00**	**1.01**	**0.00**
Year				
2025	0.00	0.00	0.25	0.00
2026	0.00	0.00	0.25	0.00
2027	0.00	0.00	0.25	0.00
2028	1.00	0.00	0.25	0.00
2029	0.015	0.00	0.015	0.00

[1] Innovative grid technologies are typically lower in both capital and operational cost

2030	0.015	0.00	0.015	0.00
2031	0.015	0.00	0.015	0.00
2032	0.015	0.00	0.015	0.00
2033	0.015	0.00	0.015	0.00
2034	0.015	0.00	0.015	0.00
2035	0.015	0.00	0.015	0.00
2036	0.015	0.00	0.015	0.00
2037	0.015	0.00	0.015	0.00
2038	0.015	0.00	0.015	0.00
2039	0.015	0.00	0.015	0.00
2040	0.015	0.00	0.015	0.00
2041	0.015	0.00	0.015	0.00
2042	0.015	0.00	0.015	0.00
2043	0.015	0.00	0.015	0.00
2044	0.015	0.00	0.015	0.00
2045	0.015	0.00	0.015	0.00
2046	0.015	0.00	0.015	0.00
2047	0.015	0.00	0.015	0.00
2048	0.015	0.00	0.015	0.00
2049	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00

Table 1: Net Present Value of comparison of benefit of faster installation timelines with 8% WACC

Based on the example above the benefit from a quicker construction solution would offer a 5% to 10% cost reduction with a range of WACC from 4% or 8% respectively.

In the worked example below the impact of being able to phase a development by rescaling a solution is shown. In order to ensure that only the benefit of rescaling a solution is demonstrated two alternative technologies are considered with both the same capital and operation cost[2]. For this example, both technologies are assumed to have exactly the same cost of installation (1 PU) are compared. The first technology is an innovative grid technology with the ability to be rescaled/resized over time with an installation speed of a year or less. Therefore only 50% of the solution is built immediately with the other 50% 10 years later when the increased capability is required. The second technology is a conventional technology that cannot be rescaled[3] and so 100% is installed on day 1, with a slower concept to installation time of 4 years. The operational cost (e.g. losses and maintenance) are taken to be identical at 1.5% of the capital cost, but for the innovative grid technology only half of this will be present in the first 10 years, when at 50% of the final solution.

A Weighted Average Cost of Capital (WACC) of 4 - 8% has been applied with a period of 20 years being used in the example.

[2] Innovative grid technologies are typically lower in both capital and operational cost
[3] E.g. a phase shifting transformer

Innovative Grid Technology Capital Cost:	1.0 PU
Innovative Grid Technology Operational Cost:	0.015 PU
Innovative Grid Technology Concept to install time:	1 year
Conventional Technology Capital Cost:	1.0 PU
Conventional Technology Operational Cost:	0.015 PU
Innovative Grid Technology Concept to install time:	4 year / 25% per annum
WACC Rate:	4 - 8%
Life of first need	10 years
Time to relocate	1 year
Cost to relocate	0.15PU

Total Benefit[+] or Cost[-]	Innovative Grid Technology		Conventional	
	-0.66		-1.01	
	Cost	Benefit	Cost	Benefit
NPV	**0.66**	**0.00**	**1.01**	**0.00**
Year				
2025	0.00	0.00	0.25	0.00
2026	0.00	0.00	0.25	0.00
2027	0.00	0.00	0.25	0.00
2028	0.500	0.00	0.25	0.00
2029	0.008	0.00	0.015	0.00
2030	0.008	0.00	0.015	0.00
2031	0.008	0.00	0.015	0.00
2032	0.008	0.00	0.015	0.00
2033	0.008	0.00	0.015	0.00
2034	0.008	0.00	0.015	0.00
2035	0.008	0.00	0.015	0.00
2036	0.008	0.00	0.015	0.00
2037	0.008	0.00	0.015	0.00
2038	0.515	0.00	0.015	0.00
2039	0.015	0.00	0.015	0.00
2040	0.015	0.00	0.015	0.00
2041	0.015	0.00	0.015	0.00
2042	0.015	0.00	0.015	0.00
2043	0.015	0.00	0.015	0.00
2044	0.015	0.00	0.015	0.00
2045	0.015	0.00	0.015	0.00
2046	0.015	0.00	0.015	0.00
2047	0.015	0.00	0.015	0.00
2048	0.015	0.00	0.015	0.00
2049	0.00	0.00	0.00	0.00

2050	0.00	0.00	0.00	0.00

Table 2: Net Present Value of comparison of benefit of phasing with 8% WACC

Based on the example above the benefit from phasing a project solution would offer approximate a 30% to 50% cost reduction with a range of WACC from 4% or 8% respectively.

This means that the cost of a solution should be included in the years as they arise, e.g. for solution options that take multiple years to develop costs should be included for each year rather than as a single capital cost in the year of commissioning. Similarly, as most technologies in this document are modular solutions, so where needs are developing so can the solution. This is unlike conventional solutions, which require the entire solution for the life of the equipment (typically 40 years) to be built at time of commissioning. Therefore, modular solutions should be included in the net present value calculation in phased steps over a number of years, compared to a single step at the time of commissioning for conventional solutions.

Also, the grid optimising technologies are much faster than conventional solutions, so they can either be built earlier, accruing additional years of benefit as a result to alternatives, or can be commenced later (e.g. the year before) than a conventional solution (many years before) saving the cost of earlier spend.

To show this the same net present value calculation is repeated but this time with a benefit that is equal to 0.15PU of the capital cost, sized to provide a positive cost benefit analysis and considered a reasonable return on the investment in a typical commercial decision.

Innovative Grid Technology Capital Cost:	1.0 PU
Innovative Grid Technology Operational Cost:	0.015 PU
Innovative Grid Technology Concept to install time:	1 year
Conventional Technology Capital Cost:	1.0 PU
Conventional Technology Operational Cost:	0.015 PU
Innovative Grid Technology Concept to install time:	4 year / 25% per annum
WACC Rate:	4 - 8%

Total Benefit[+] or Cost[-]	**Innovative Grid Technology**		**Conventional**	
	0.48		**0.20**	
	Cost	**Benefit**	**Cost**	**Benefit**
NPV	**1.15**	**1.62**	**1.00**	**1.21**
Year				
2025	1.00	0.15	0.25	0.00
2026	0.015	0.15	0.25	0.00
2027	0.015	0.15	0.25	0.00
2028	0.015	0.15	0.25	0.15
2029	0.015	0.15	0.015	0.15
2030	0.015	0.15	0.015	0.15

2031	0.015	0.15	0.015	0.15
2032	0.015	0.15	0.015	0.15
2033	0.015	0.15	0.015	0.15
2034	0.015	0.15	0.015	0.15
2035	0.015	0.15	0.015	0.15
2036	0.015	0.15	0.015	0.15
2037	0.015	0.15	0.015	0.15
2038	0.015	0.15	0.015	0.15
2039	0.015	0.15	0.015	0.15
2040	0.015	0.15	0.015	0.15
2041	0.015	0.15	0.015	0.15
2042	0.015	0.15	0.015	0.15
2043	0.015	0.15	0.015	0.15
2044	0.015	0.15	0.015	0.15
2045	0.015	0.15	0.015	0.15
2046	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00

Table 3: Net Present Value of comparison of benefit of faster installation with 8% WACC

Based on the example above the benefit from building 3 years earlier would offer an increase in the cost benefit analysis of approximately 50% to 135% with a range of WACC from 4% or 8% respectively.

There is an additional benefit that the technologies in this paper can provide that needs to be reflected in the avoidance of stranded assets. Many of the technologies are almost entirely re-deployable if a need changes, meaning that the residual value of these assets should be included if this aspect is considered in a term contract Cost Benefit Analysis. Rarely can conventional solutions be relocated[4] and these assets generally remain stranded.

In the worked example below a net present value calculation is made valuing the ability to redeploy. This example shows a situation where a known secondary need is identified, that allows the innovative grid technological solution to relocated within a year after the initial need and the associated benefit ceases. This cessation of the original need occurs 10 years after installation of the present limit of forecasting in most development plans. The innovative grid solution assumes a further 0.15PU capital expenditure is required to move this technology to the new location, while for the conventional solution the asset is not relocatable and therefore stranded. The same main parameters with regard to costs and WACC rate are the same as previous examples, with the rate of benefit for the second need being the same as the first at 0.15PU.

Innovative Grid Technology Capital Cost: 1.0 PU
Innovative Grid Technology Operational Cost: 0.015 PU
Innovative Grid Technology Concept to install time: 1 year
Conventional Technology Capital Cost: 1.0 PU

[4] e.g. a newly built line or station

Conventional Technology Operational Cost: 0.015 PU
Innovative Grid Technology Concept to install time: 4 year / 25% per annum
WACC Rate: 4 - 8%

Total Benefit[+] or Cost[-]	Innovative Grid Technology		Conventional	
	0.70		0.00	
	Cost	Benefit	Cost	Benefit
NPV	**1.15**	**1.86**	**1.12**	**1.12**
Year				
2025	0.00	0.00	0.25	0.00
2026	0.00	0.00	0.25	0.00
2027	0.00	0.00	0.25	0.00
2028	1.00	0.15	0.25	0.15
2029	0.015	0.15	0.015	0.15
2030	0.015	0.15	0.015	0.15
2031	0.015	0.15	0.015	0.15
2032	0.015	0.15	0.015	0.15
2033	0.015	0.15	0.015	0.15
2034	0.015	0.15	0.015	0.15
2035	0.015	0.15	0.015	0.15
2036	0.015	0.15	0.015	0.15
2037	0.015	0.15	0.015	0.15
2038	0.150	0.00	0.015	0.00
2039	0.015	0.15	0.015	0.00
2040	0.015	0.15	0.015	0.00
2041	0.015	0.15	0.015	0.00
2042	0.015	0.15	0.015	0.00
2043	0.015	0.15	0.015	0.00
2044	0.015	0.15	0.015	0.00
2045	0.015	0.15	0.015	0.00
2046	0.015	0.15	0.015	0.00
2047	0.015	0.15	0.015	0.00
2048	0.015	0.15	0.015	0.00
2049	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00

Table 4: Net Present Value of comparison of benefit of relocation after 10 years with 4% WACC

Based on the example above the benefit from relocation with a WACC rate of 4% the conventional solution would just breakeven, but at a high rate would not. With a WACC of 8% the cost benefit analysis would show a 0.15PU loss for the conventional solution if the need would cease after 10 years stranding the asset. It is considered in the example that typically a stranded asset like a new line, cable station or transformer are left in service and accrue losses as there is a cost of decommissioning that is higher, assets deteriorate more quickly when de-energised and/or the perception that maybe a need will return, hence in the example the operational costs of 1.5% of the capital cost per annum continue. Even if the asset was de-energised the reduction in operational costs would not make the cost benefit analysis breakeven across the range of WACC.

By contrast with the ability to relocate the innovative grid technology will always show a positive cost benefit analysis. In fact, it provides a positive increase in the cost benefit analysis by approximately 0.4PU to 0.7PU of the original cost of the deployment with a range of WACC from 8% to 4% respectively.

In this example, the cost benefit analysis calculation has been made with the relocation to a second network need. An alternative approach is to use a residual value of the assets and decommissioning cost at the end of the network need period for each technology. For a technology that cannot be reused or parts of the project e.g. civil works, that cannot be reused then that part if considered to have no residual value. Care must be taken with residual value to not base this on remaining life expectancy, but the potential value they will have to be reused. Many conventional assets are bespoke and not modular, or are of a past standard size/design, and in fact have no residual value despite their remaining life expectancy. Decommissioning costs must also be included with recent environmental legislation, making the recycling of assets and site restoration very costly e.g. transformers, stations or cables. This report does not apply this approach due to normal industry practice retaining these assets in service, and not incurring the costs of decommissioning, or revenue loss.

For the examples provided above the discussion has been around a single bespoke project cost benefit analysis. When looking to perform a single cost benefit analysis that will be used to determine what technology to be used and how, for a repeated network issue much of the same techniques can be used. These ‘grouped’ cost benefit analyses should be set up on the basis of the average or most common situation that arises.

For technology lead-times this is easy. DSOs commonly have an expected time to complete for each conventional technology or project based already. DSOs are used to determine when to start planning a solution for its timely commissioning. Comparing this to faster innovative grid technologies (based on this report, manufacturers or peers past experience) is therefore relatively simple.

The same is true for faster installation times. DSOs can calculate the ‘value’ or benefit a project can provide based on typical need. For example, if the typical value of a MW of additional line capacity is determined by the system marginal price, and a technology can typically provide X% increase in line capacity based on generic system studies, then the value per annum of an earlier solution per annum can be calculated. This can be compared with the typical cost of deployment of a solution using the local WACC and therefore the typical value of each technology can be determined and compared to make a ‘grouped’ cost benefit analysis selection of what technology is to be used when needs arise earlier than some technologies can deliver. In short is it worth using a particular technology in these cases as it can deliver early. From experience, this type of analysis is frequently cut short as the typical cost of an innovative solution is often lower than a conventional one and earlier delivery only increases the strength of the cost benefit analysis in its favour.

For evaluating the impact of relocation, the typical annual value of a technology proposed in faster installation times above, can be reused. This would define the benefit the technology will provide when used or reused to address needs in the network. Combined with a probability of a need changing over the life of an asset and therefore the risk of stranding, derived from recent past experience by the DSO, can create a typical duration of a need before a change arises requiring a new solution e.g. the duration/life expectancy of the network need. A change to network needs in the progress to decarbonisation is far from uncommon, with €400 billion being planned as needed in the next 10 years and growing, much of this will be network strengthening replacing existing assets that have become stranded. This trend is only expected to grow in future as we move to 2050. Therefore, the ability to relocate will also become more common and grow, and the 10 years used in the calculations in this report is also considered a very reasonable period before a network need will significantly alter.

Installation and Testing

The grid optimising technologies in this paper are all markedly different in their deployment to most conventional technologies presenting reduced risk. They will be explained in greater detail in the following section. Each is considered commercially available, with field deployments and a growing operating record of accomplishment.

Each supplier can provide method statements for deployment, and recommendations on how to install quickly and easily based on past experience.

For technologies that include hardware they are modular in nature and should be installed allowing for future possible developments.

Innovative Grid Technologies: Specific Deployment Recommendations

In additional to the general deployment recommendations in the preceding chapter each technology has a number of unique and specific capabilities and deployment needs. This chapter outlines for a range of innovative technologies a general understanding of the technology and specific recommendations for these.

On Technology Readiness Level (TRL)

In the following chapters, a level of readiness for each of the technologies will be provided. Such level is indicated as per the Figure below. The TRL scale was originally developed by NASA in the 1970s, before it was successively adopted by the military and the overall aerospace industry. It is a method for estimating the level of maturity a technology has currently reached, for conceptual to established industrial deployment [16].

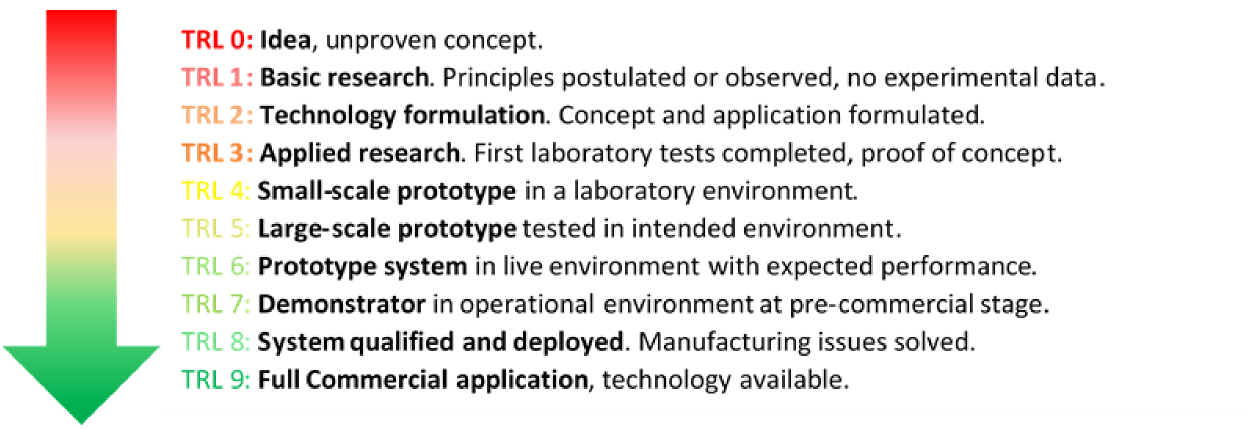

Figure 1: Technology Readiness Level scale

Advanced Conductors

High-level Description

Advanced Conductors are a symbiotic technology to others listed in this document and permit the Distribution System Operator to double the transmission capacity on a given line route whilst ensuring minimal conductor sag and mast/pole replacement. They fall under the general classification of HTLS (High Temperature Low Sag) but yield significant advantages over their traditional steel-cored HTLS equivalents.

Advanced Conductors comprise either a Polymer Matrix Core (PMC) or Metal Matrix Core (MMC). Compared to steel, PMC and MMC designs offer greater strength, lighter weight and a lower coefficient of thermal expansion – which mitigates excessive sag under high electrical load conditions. The core's lighter weight allows the incorporation of approximately 30 percent more aluminum – without a diameter or weight penalty. The added aluminum content and enhanced electrical properties reduces the conductor's resistance and associated IR power losses. Reduced line losses have profound benefits as pointed out in recent studies which reveal that 2/3 of T&D (Transmission & Distribution)-associated losses lie in the wires and not the substation [17].

Figure 2: Advanced conductors samples (courtesy of CTC Global, Epsilon Cable)

The inherent attributes of the PMC and MMC cores generally permit installation of these conductors on existing towers with little or no foundation or strengthening work required. This can dramatically lower project costs, simplify permitting, and expedite project completion – which are all very significant factors in Europe. The conductors share many fittings with their steel-core equivalents, now also including wedge-clamps.

At the time of writing, approximately 20,000km of Advanced Conductors have been installed throughout Europe over the last 20 years and nearly 200,000km worldwide. This solution is readily available and well proven, therefore TRL 9 would be applicable (depending on the individual manufacturer's development path).

Applicable Standards

The following are the applicable standards relating specifically to PMC cores:

Standard	Comment
ASTM B987-20	ASTM B987 is a long-standing standard for evaluation of the composite core. The-20 variant includes a requirement for a more robust galvanic protection between the core itself and the aluminium strands that surround it.
IEC 62818	IEC 62818 adds to the ASTM standard by including longevity prediction using the Arrhenius method and certain thermographic tests relating to the matrix

Table 5: Applicable standards for advanced conductors

Risk Mitigation - Inspection Systems

If seriously mishandled through excessive bending during installation, Advanced Conductors carry the risk of compressive failure. In response to this, certain manufacturers have developed inspection systems to monitor the condition of the core before, during and after installation (using for instance optical embedded systems, or dielectric breakdown). Recent innovations permit inspection of the core at any time throughout the conductor's life; of significant importance following unforeseen impact events such as tree or lightning-strikes. Enhanced inspection systems also add to Asset Management security in the event that line-carts are used during routine MRO. Such inspection systems are already being widely deployed in Europe, a recent example being Elia [18].

CBA

CBA naturally varies from project to project, considering the following factors:

- If existing, what conductor is to be replaced?
- Tower/foundation strengthening requirements (if any), comparing Advanced Conductors with other technologies.
- Carbon emissions associated with the line-losses, or reduced generation requirements resulting from conductor efficiency.

Typically, Advanced Conductors yield a project payback within a very short time. The greatly increased capacity reserve also future-proofs the line to cater for redispatching, future RES generation and foreseen increases in line-loading. In many cases, the *overall* project costs associated with implementing Advanced Conductors are lower than traditional conductors (including steel-core HTLS), since less tower strengthening/replacement is generally required.
A recent report by the Energy Institute at Haas states that Advanced Conductors effectively enhance the viability of RES projects from the outset [19].

Digital Twin platform

High Level Description of technology

Digital Twin Platforms are an innovative part of the modernisation of the grid technologies, using data analytics and modelling, delivering monitoring of the assets, dynamic line ratings, topology optimisation and power flow control.

Digital twin technologies are creating an "image – twin" of a real asset by its physical-mathematical modelling by advanced analytics and algorithms. By feeding the algorithms by real time data, the model will create results describing the operational behaviour of the modelled asset.

The results represent the reality, the model behaves like reality. The digital twin model is a single holistic multi-directional system, connecting into the real behaviour and capturing history, present and future. TRL9 can be considered for this technology, considering the existing track record amongst different utilities in Europe.

Benefits of a digital twin platform

- A platform provides all distributed data of an asset to enable collaboration of all involved stakeholders to solve common problems and needs.
- Development and implementation to solve specific problems and needs over internal or even international organisational gaps.
- Support of daily operations by the digital model of reality - rebuilding the "whole picture" for being able to make decisions based on updated new information and for solving complex challenging problems. In case of advanced AI technologies and machine learning features daily and future operation can be predicted.
- Due to the nature of the digital grid technology, the usage of additional sensors or measuring hardware can be minimized in many areas.
- AI analytics of the Platform are creating measures to foster grid stability and security and adapt system operation to the new mix of resources, considering the EU's regulations and tariff policies.
- Realization of an integrated European digital grid, able to unleash the Energy Transition.

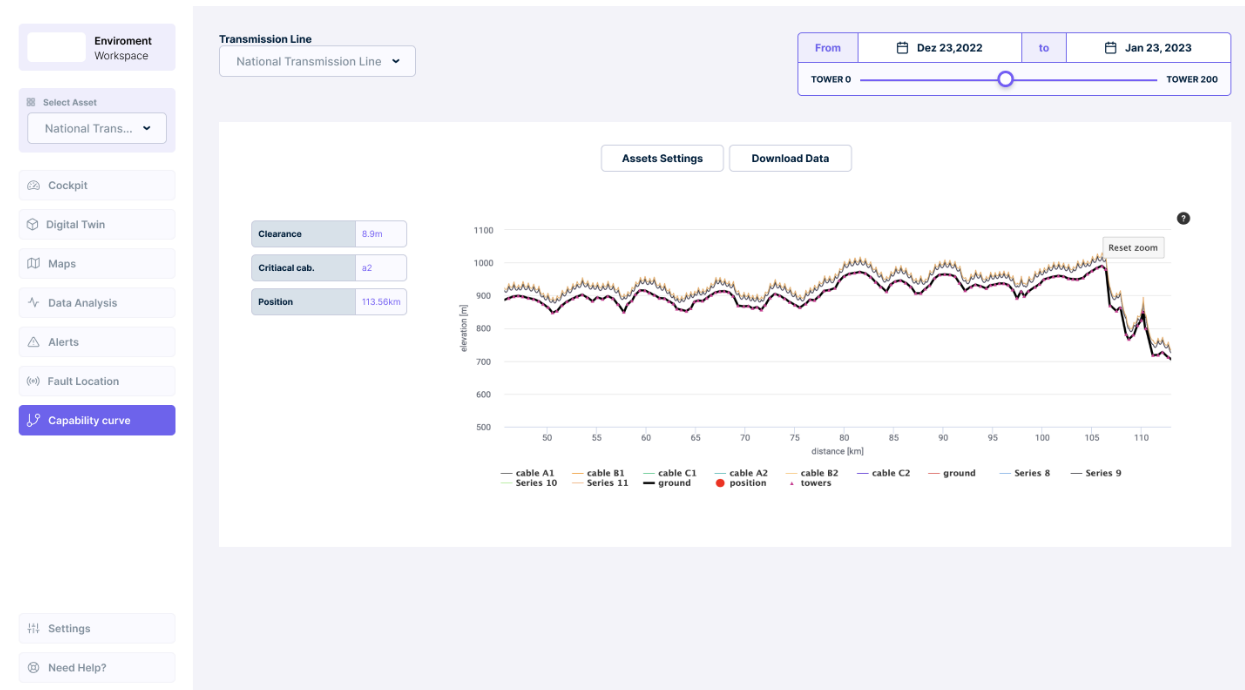

Figure 3: Presentation of the electrical line in a digital twin platform

With the Digital Twin platform any line can be modelled, showing all parameters at each point along the line, be it electrical values, sag per span, clearances or cable temperature values etc.

Recommended technology risk management

Important for digital twin platform operation is maximum accuracy, the potential deviations between the real asset parameters and the parameters resulting on the twin platform.
To manage that risk, it must be secured that:

- The analytical algorithms are considering the international standards (DIN, IEC, IEEE etc.) for any asset modelling and operational calculation.
- The physical asset data and parameters for the modelling of an asset are available and updated or approximated within acceptable tolerances
- The necessary real time input data for daily operational simulation are provided precisely and without time delay in defined tolerance bandwidth.
- Solutions must be capable of tackling challenges for big data, providing all cyber security measures necessary for protecting critical national infrastructure assets

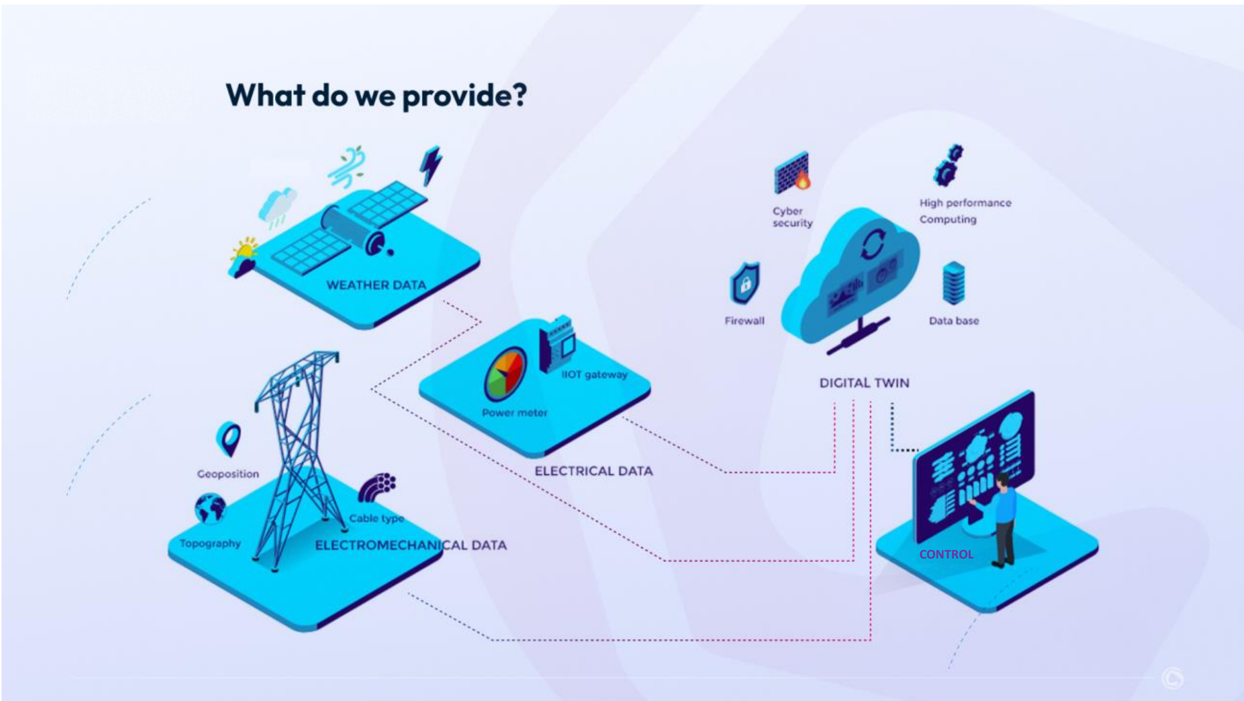

Figure 4: Schematic illustration on how and where the platform obtains its data

After start-up of the digital platform, Pilot/type test measurements in the field may be carried out in order to compare the measured field values with the resulting data on the platform.

Distribution Grid Operations

A Digital Twin platform for DSOs should take into consideration all available electromagnetic and physical project parameters of the electrical elements, such as switchgear, transformers, lines and towers, topography and geometric data.

The platform usually is modelling the installation in a cloud application, either on or off premises.

For the operation of the digital twin platform and generating the results, the following data are usually necessary: comprehensive weather data on a high granularity level, satellite data and relevant real time electrical data from the grid operators.

The results of all required parameters, predictions, alerts and warnings will be presented on the digital platform on operators' premises by acknowledging all electrical and thermal parameters in real-time and predicting mode providing GET functionalities like dynamic line ratings, topology optimization and power flow control.

Recommended Technical Assurance Process

It is recommended that the technical assurance process takes recognition of the work of joint Task Force Digitisation of the Energy System Action Plan (TF DESAP) of EU DSO Entity and ENTSO-E. Both signed an official Declaration of Intent to develop jointly the Digital Twin of the EU electricity grid in December 2022. This digital twin will be a sophisticated virtual model of the European electricity grid which aim is to enhance the efficiency and smartness of the grid throughout the energy system as a whole and through continuous investment and innovation efforts for years to come.

It is intended to ensure the development of innovative solutions and coordination of investment in five areas:

1. Observability and controllability;
2. Efficient infrastructure and network planning;
3. Operations and simulations for a more resilient grid;
4. Active system management and forecasting to support flexibility and demand response;
5. Data exchange between TSOs and DSOs.

It is recommended that the outcome of this work in these five areas is used to ensure the adequacy of digital twin to meet the expected needs and capabilities as part of the technical assurance process by any system operator.

The driving force behind this development the EU action plan considered that digital twin will not be created in one go but will be a continuous investment and innovation effort for years to come, but that digital twin developments by national bodies would and should value from the work of TFDESAP in their own digital twin developments.

Deployment Process Stages

As Digital Twin Platforms are an innovative part of the modernisation of the grid technologies, more and more operators are developing their own models or are using platforms of innovative company developments.

The EU is requesting from utility level to the goal of an EU pan-national digitisation of the grids, harmonisation of necessities, standards, adherence to regulations – or adapting regulations to enable to harvest the new technologies contributions - need to be defined in process steps with realistic/ambitious time horizons.

Typical solutions of Digital twin platform providers could be technically harmonised by EU funded HORIZON programs or by any DSO council related working group.

Recommended CBA methodology

CBA of the implementation of digital twin platforms is under way by some DSO/utilities for their asset portfolio, showing advantages for a smart way of grid monitoring and operation, like recognizing upcoming critical grid situations, real-time and predictive congestion identification, proposals for countermeasures, optimization of the power flow control incl. forecasts of the next day's etc.

It is important to gain a holistic picture by defining common evaluation criteria. Such activities to be supported by DSO council related working groups, for example.

As AI based algorithms are part of the digital twin platform, one of the benefits is not only the permanent monitoring of the grid but also the analytics that will recognize any changes in the normal behaviour and will alert the operator of any fault coming up. Therefore, a digital twin platform enables the operator to take action even before a fault or risk will appear, thus saving considerable OPEX costs by usage of the digital twin platform.

Dynamic Line Rating

High Level Description of technology

DLR is an operational improvement technology otherwise known as a Grid-Enhancing Technology (GET) that adjusts a line's thermal rating based on actual and predictive weather conditions including ambient air temperature, wind speed and direction, humidity, direct and diffuse solar irradiance, and precipitation. By doing so, DLR can give crucial insights to systems' operators on how much energy they can or cannot transmit in a given period. As a matter of numbers, DLR can increase, on average, 30% of a line's transmission capacity over a year, while increasing a day's transmission capacity by over 200% respectively. This is confirmed in the ENTSO-E Technopedia [16] "An increase of ampacity can be achieved up to 200% depending on the weather conditions and required confidence intervals. The highest potential is observed in areas of high wind RES, as convective cooling and loading of overhead lines are strongly coupled."

An increase in ampacity supports grid operators in making more efficient use of existing grid assets and avoiding congestion restrictions."

By utilising mathematical, statistical, physical, electromagnetic, mechanical and thermal models standardized by international entities such as CIGRE, EPRI and IEEE, it is possible to create a highly precise digital twin of a power asset to monitor all variables of interest. DLR requires line-specific data, such as conductors' specifications, towers' locations and silhouettes, combined with real-time and predictive monitoring to provide forecasts for operation planning.

Dynamic Line Rating calculations may or may not include the use of field-deployed sensors. On a global basis, DLR has been successfully implemented by many transmission or distribution operators, with extensive track record and associated publications, therefore TRL9 is applicable to these technologies.

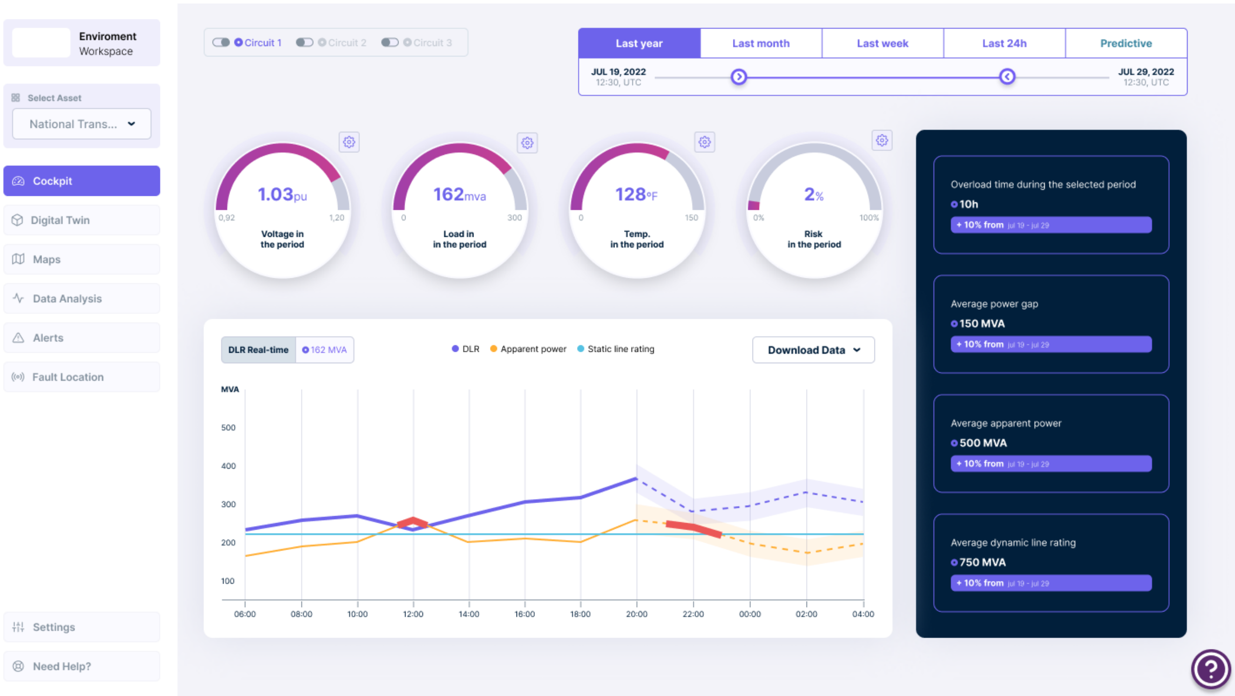

Figure 5: Interface of the software with values about the monitored line

Recommended technology risk management

There are two types of risk involving DLR for DSOs: granularity and accuracy of forecast up to e.g. 7 days in the future.

The first risk is to the adequacy of dynamic line rating calculation is the technology applied for the distribution grid to perform this role. By not knowing precisely which spans are the limiting ones DSOs can wrongly identify a curtailed span and make costly decisions to constrain and/or waste resources doing remedial work in the field.

High quality DLR systems avoid this risk by calculating the DLR rating for every span along a circuit and not just at what is the most critical span identified in the original line design which only use static line rating calculation parameters. The methodology for calculating the DLR can use direct line measurement sensors (e.g. line mounted sensors), local measurement sensors (e.g. tower mounted weather stations or LIDAR), or that do not require sensors at all (e.g. using a weather data provider or digital twin input). Weather data providers can currently give a 90-meter spatial resolution for the parameters needed for a DLR line calculation e.g. wind speed, wind direction, ambient temperature, solar radiation. DLR can even be performed on multiple subdivisions within one single span for higher accuracy.

The second risk rises due to the accuracy of the DLR forecast. A forecast for the maximum admissible ampacity on a line will have reduced accuracy as longer the forecast is predicted.

However, by continually refreshing and revising the source data for the DLR, and by adjusting the methodology for the forecast, the forecast will become increasingly accurate.

System and Equipment Modelling

The DLR ratings calculated can be reflected and used simply in operation, markets and long-term planning by taking the calculated DLR value and substituting it for the existing static ratings. Dependant on the application the time frame the DLR is calculated to represent will change as will the certainty or accuracy of the DLR.

Even for immediate real time operation, any decision that is made at any time will alter the networks operation state and not only the instantaneous impact of an action must be assessed. In fact, any operational action is assessed over a longer time-period until any remedial actions that might be required due to scheduled and a reasonable range of unscheduled changes to demand, generation or to the network. These remedial actions may not be possible immediate and could take hours like starting a large generator, which must be factored in before an action is taken.

Therefore, for adequate modelling of DLR into system network modelling in the control room and markets DLR predictions are always required stretching from real time out for many hours. The uncertainty of this will grow the further into the future and good DLR calculations are required and necessitate the use of proprietary systems that can adapt, that benefit from development and refinement from highly skilled dedicated experts.

For DLR systems that do not use sensors, the overall equipment needed is reduced. The central software is typically located in the customers control room servers but could be sited at any location or via cloud computing and the equipment to provide the necessary communication pathways are the only physical equipment requirements. The data processing pathways are required to meet the customers visualisation (e.g. control room or back-room teams), data processing and/or storage e.g. to support use in energy markets or system operation, and along with the necessary servers may already exist meaning that no new equipment may be required.

Any in the field sensors local or mounted onto the line typically do not change the parameters of the line, operating independently with their own power source and communication.

Tendering Specification Recommendations

Dynamic line rating calculation methods are diverse with many proprietary software that may or may not use sensor-based technologies. Where used, sensors can use a variety of different methods to determine real time and forecast dynamic line ratings e.g. conductor temperature, weather conditions, visual positioning, strain gauges or conductor vibration.

However, nearly every system applies either CIGRE TB601 and/or IEEE 738 methodologies in their DLR calculations and these provide a consistency to the calculation at least.

The key procurement technical requirement for DLR selection is to avoid selecting the method of DLR calculation in favour of the functional requirements of the DLR system. These functional requirements can be relatively simplistic. They include the desired accuracy of the DLR calculation normally specified for the real time calculation and as a +/-% tolerance of error of the calculation when at the maximum dynamic line rating expected (e.g. +/-5% tolerance when at 25% above the nominal static line rating). The functional requirements for the DLR calculations should also specify, how the DLR systems are to be visualised and used. For example, some of the following might make up functional requirements in a DLR system:

- Size of deployment e.g. one of more lines, and total length
- Compliance with international recognised calculation method e.g. CIGRE TB601 or IEEE 738.
- The right protocol language to communicate with existing SCADA and EMS systems.
- Ability to provide intact and worst-case N-1 DLR ratings.
- Refresh rate of DLR system.
- Accuracy of DLR calculation, using +/-% of maximum DLR rating expected.
- Maximum predictive length of DLR forecast in hours;
- System calculates bespoke DLR for every span in lines.
- Speed of deployment on one or more lines.
- Availability of the system set in % per annum.
- Held, shown or used by the control room EMS or in a standalone PC or system.
- To update settings in automated EMS responses or special protection schemes.
- Set up with DLR ratings available to back-room teams for operational or long-term planning.
- Redundancy of DLR servers or data storage.
- Etc.

Many of these functional requirements would be best discussed or worked on collaboratively and typically, suppliers would work with system operators to guide and inform these choices.

Type tests

Type tests are not necessary. However, for results' validation, measurement of the desired variables with adequate and calibrated equipment may be performed to provide confirmation of the accuracy of the calculation method.

There are many DLR deployment globally, below shows some references use cases:

Voltage Level	Contract	Country
380kV	Since April 2022	Germany
220kV	Since January 2022	Austria
230kV	Since April 2021	USA
60/220 kV	Since October 2022	Portugal
220kV	Since April 2022	Canada
500kV	From Dec/2020 to Jun/22	Argentina
400 kV	Since July 2022	Portugal
66/220/400 kV	Since December 2019	Spain
500kV	Since May 2022	Chile
150kV	Since March 2021	Uruguay

Table 6: Reference Dynamic Line Rating Projects

Deployment Process Stages

DLR deployment can be broken into three main stages:

1. Investigation and Preparation of circuit[s] to receive DLR
2. Installation of necessary hardware and software
3. Post commissioning evaluation and tuning of DLR

Typically, the first two steps can be done very rapidly in as little as 3 - 4 months, with longer installation (step 2) periods dependant on the necessity for line outages to install in field line sensors, where required. Dependant on the sensor technology, the criticality and scale of the overhead line this can add months or years to the installation process.

Training in the use of the system and the use of DLR in normal operation/market activities and/or DLR system maintenance is normally also provided at the same time as the software and hardware installation process

Normally, the third step occurs during the first year of operation and can be done in tandem with the operation of the DLR system.

CBA methods for this technology

The CBA method utilized for DLR systems is the same as recommended elsewhere in this paper with the total benefits and the total costs for the customer per month being used.

Building a Net Present Value calculation of this is relatively simple.

The capital and operational cost of the DLR system being taken from estimated budget costs from the supplier or later from the procurement process including the maintenance contract.

The use of network or market modelling, often using past annual line loading data and environmental data can provide the typical expected additional capacity that the DLR system will realise and the coincidence of this with periods of restriction on power flows that an enhanced line rating may alleviate. The value of this can calculated either directly using market modelling with the revised DLR ratings, or indirectly by considering the market price of energy during those periods to create and annualised saving attributable to the use of DLR ratings

By combining both of these in a NPV over a suitable approved time period, normally the regulatory approved period (normally 20 – 50 years) for network investment decisions, a positive CBA can be determined. Also, the payback period for a DLR system can be assessed, which is the time it takes for the entire capital and operational cost (up to that point in time) to be paid by the benefits that DLR system provides.

Modular Power Flow Control

High Level Description of technology

Modular Power Flow Control is a device that is designed from its inception to be modular in nature, combining a variable number of the units together in operation to operate as one to control the flow of power.

At present, the commercially available modular power flow control devices are Static Synchronous Series Compensators (m-SSSC). They are part of the FACTS family, injecting a leading or lagging voltage in quadrature (aka shifted 90 degrees) with the line current as shown in Figure 4, using power electronics. This reactive voltage injection makes the effective impedance of a circuit increase or decrease, which increases or decreases the loading on the circuit respectively.

Modular Power Flow Controllers can inject the voltage independently of the line current. This allows the devices to provide a linear not stepped response and to modify the effective reactance of the circuit immediately whilst injecting and at any point in time up to its rated value. An example, of the Modular Power Flow controller operating range is shown in Figure 6.

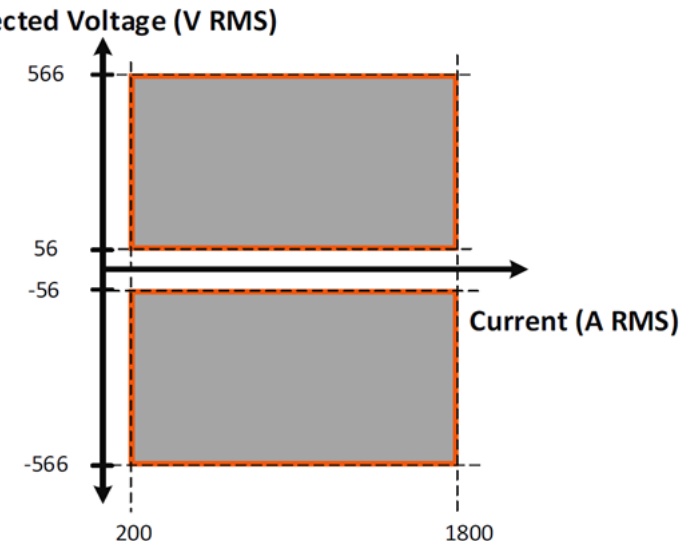

Figure 6: SmartValve 1-1800 Voltage Operating Range

They do this by harvesting energy from the line current directly and using this to generate the necessary reactive voltage. Consequently, as they are self-powered series connected devices their optimal design is as a 'live tank' device, operating at the line voltage and isolated from the ground. Either this can be done by insulated support structures, line deployment or rapid insulated trailer mounted mobile deployment, explained in more detailed in the Installation section below. The 'live tank' design means that the same device can be used at any voltage level, limited only by the ability to physically site the device where it is needed and the economic performance (cost benefit analysis) of the device compared to that of the need.

The size of commercially available Modular Power Flow Control devices vary based on their ampacity, with typically 1800A and 3600A devices currently available. They also vary in size with 1MVAr and 10MVAr units available. It should be noted that the relative size of the units e.g. 1MVAr is a combination of the maximum rating 1800A and the maximum voltage they can inject 566V. As a result, the MVAr rating of the devices cannot be directly compared to that of other Power Flow Control devices, e.g. series capacitors, reactors, phase shifting transformers, etc.

To limit the images and descriptions in this guide, the devices shown will focus on an 1800A, 1MVAr units that are considered the most suitable for widespread DSO network use.

The typical operational reactive range of an 1800A 1MVAr device is shown in Figure 7, with the device being operational between 200A and 1800 A. The device also has a short-term overload capability. The time an overload may be endured reduces as the size of the overload is increased, for example, a 120% overload can be withstood for 2 hours, but a higher overload would be less than 2 hours.

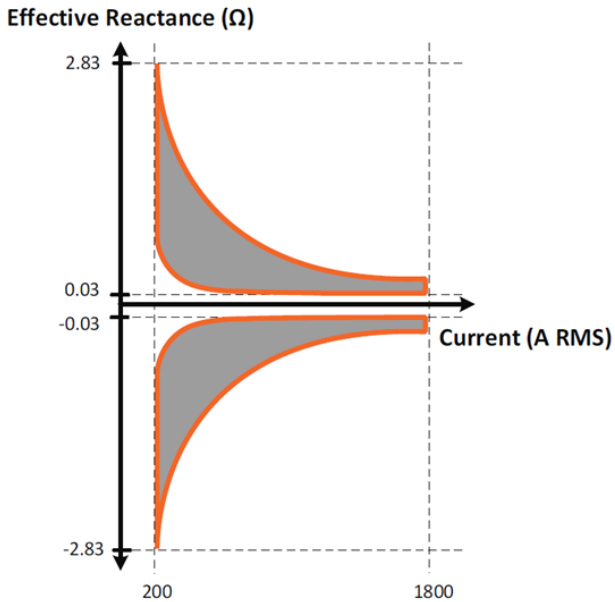

Figure 7: SmartValve 1-1800 Reactance Operating Range

As can be seen from the diagram in Figure 7, the higher the current the lower effective impedance that each device will contribute. Therefore, often a smaller level of impedance is required when the devices are deployed on the overloaded circuit that power flow needs to be reduced. However, this can result in a number of devices being required due to the lower effective impedance at high current. Therefore, a more effective solution can be to use the devices in pull mode, requiring a higher level of impedance, but potentially a smaller number of devices. To optimize the effectiveness of the solution against its cost, this relationship must be considered when assessing the network needs.

Modular Power Flow Control can be controlled in number of ways. They can be programmed to turn on when a certain level of current is seen on the line. The control arrangements can be integrated into the Energy Management System ('EMS') of the utility deploying them allowing direct control through the EMS. In terms of technological maturity, modular PFC already achieved TRL9 due to successful implementation in Americas or Europe.

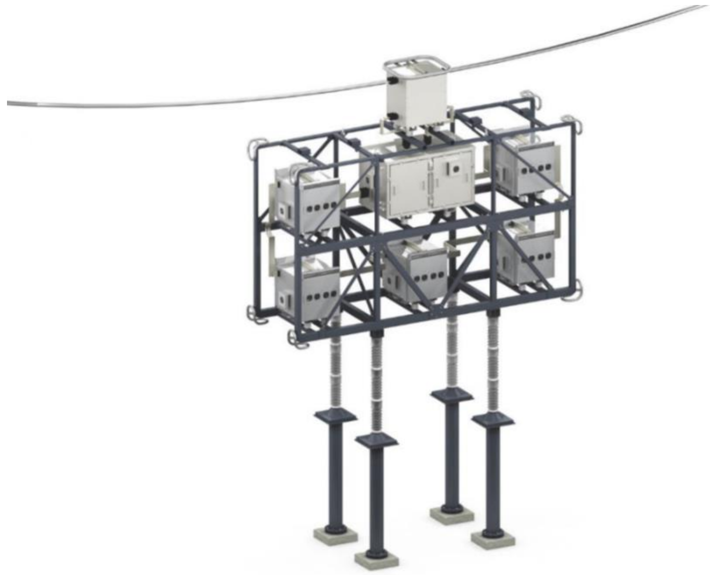

Figure 8: Layout of ground based 1-1800 SmartValves

Communications

Communications between the MPFC can either be through encrypted ISM (Industrial, Scientific, Medical) radio signals or fibre optics.

The ISM frequencies are radio bands reserved for the use of radio frequency energy for industrial, scientific and medical purposes other than telecommunications.

The ISM signals are collected by a radio antenna connected to a device that manages the secure wireless link between the MPFC and the gateway communications module, which provides for operation and management of the devices and supports multiple communications approaches.

Figure 9 is a schematic of the communications arrangements.

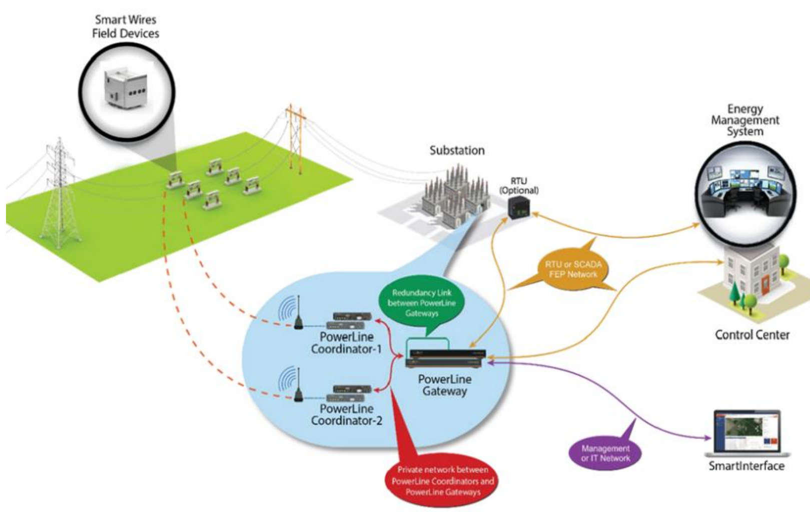

Figure 9: Schematic of Communications Arrangements for the Project

Recommended technology risk management

Modular Power Flow Control technology is an extremely low risk technology in comparison to many existing conventional power flow control technologies for the following key reasons.

It is typical for Modular Power flow Control devices to be designed with an internal bypass. This switch is a 'normally closed' switch which means that in a failure of power to the devices, its circuits boards, controls, wiring, etc. the device defaults to closed and the device is bypassed, and the circuit will remain in service. In comparison, failure of nearly every other asset on the system will require it to be isolated by the opening of the circuit. This means that the failure of any one unit does not present the same scale of risk as conventional technologies whereas a single unit the entire capability would be lost.

The speed of isolation (typically 1ms or less) in the event of a fault also means that the impact on system protection is eliminated as the devices will be faster than the protection to operate, resulting in the protection experiencing the same fault conditions as before the devices are deployed. This removes the risk of failure in design or modification to protection, or the inability to apply new settings. It is recommended that the need for amendments to protection be considered as part of the initial evaluation of the technology, ideally based on existing third-party deployment experience and evaluations, to confirm the negligible impact of the devices on protection. Thereafter this generic due diligence of the technology, deployments need not reconsider protection implications.

Unlike other items of plant and equipment the Modular Power Flow Control are centred on modularity and the ability to combine units together seamlessly to scale their capability, or to offer a wider range of services [21] [22]. Consequently, they are also designed to be quick to assemble, move and replace. This means that there is virtually no risk of asset stranding if the system needs change or move.

It is recommended therefore that Modular Power Flow Control be deployed to address the immediate need and not over dimensioned to account for a range of possible future needs over the 40-year lifetime of the devices. It also recommended that a periodic reassessment on the performance and need for the devices is performed. Typically, this would be done as part of the normal modelling studies of network's needs. This can identify whether to resize and/or move devices to more pressing needs.

Remaining risk from ancillary items such as the communication devices is typically also minimized through the standard duplication of these devices, their power boards and fibre-optic connections, so that they are effectively N-1 compliant. However, in the unlikely event of a double failure of the devices or where used the customers SCADA communication, there is an ability for the devices to be either locked in their present position, revert to their own on-board controls working independently or to isolate themselves. It is recommended that for each deployment that the optimum approach between these options is considered and identified in the design specification.

Recommended Technical Assurance Process

It is recommended that the technical assurance is completed using a type test approach. This means that the technology has a more detailed assessment initially by the system operator and their experts, generally as part of a first deployment, which is not repeated for subsequent deployments.

It is also recommended to use the wide range of published test results of the devices, by previous research centres and bodies. Many of these will have assessed the same or more onerous system conditions than would be experienced on the system operator's network. As a result, the bespoke work that is required to assess the technology is reduced for best practice due diligence. Equivalent network standards that exist and that have been applied to Modular Power Flow Control Devices are also a key method of reducing technical assurance, a table showing typical standards that have been applied is shown in table 1 to 3.

Requirement	Applicable Standard	Title
Fault current	IEEE C37.32 – 2002	High Voltage Switches, Bus Supports, and Accessories Schedules of Preferred Ratings, Construction Guidelines, and Specifications
EMC Compatibility	IEC TR 61000 – 4-1:2016 series	Electromagnetic compatibility (EMC) – Part 4 – 1: Testing and measurement techniques – Overview of IEC 61000 – 4 series
	IEC 62271-1	
Lightning/Surge	IEEE Std. 4 – 1995	IEEE Standard Techniques for High – Voltage Testing
Maximum Operating Voltage (Corona and RIV)	IEEE C37.32 – 2002	High-Voltage Switches, Bus Supports and Accessories Schedule of Preferred Ratings, Construction Guidelines and Specifications
Harmonic Content	IEEE 519 – 2014	IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems
	IEEE 1547	IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems
	IEC/TR3 61000 – 3 – 6:2008	Electromagnetic compatibility (EMC) – Part 3 – 6: Limits – Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems
Insulation Coordination	IEEE 1313.2 – 1999	IEEE Guide for the Application of Insulation Coordination
	IEC 60071 - 2	

Electrical Safety	NESC C2 – 2012	National Electric Safety Code(R) (NESC(R))

Table 7: Electrical Standards

Applicable Standard	Titles
IEEE 1815 – 2012	IEEE Standard for Electric Power Systems Communications – Distributed Network Protocol (DNP3)
IEC 62351 series	Power systems management and associated information exchange – Data and communications security
IEC 61850:2016 Series	Communication networks and systems for power utility automation
IEC 60870 – 5:2016 Series	Telecontrol equipment and systems – Part 5: Transmission protocols
IEEE 802	Local and Metropolitan Area Network Standards

Table 8: Cybersecurity Standards

Requirement	Applicable Standard	Title
Intrusion Protection (Water and Dust)	IEC 60529 – 2004	Degrees of Protection Provided by Enclosures
Thermal Cycling	IEC 61284	Overhead lines – Requirements and tests for fittings – Clause 12 and 13
Electrical Connections	ANSI C119.4	American National Standard for Electric Connectors–Connectors for Use Between Aluminum-to-Aluminum and Aluminum-to-Copper Conductors Designed for Normal Operation at or Below 93°C and Copper-to-Copper
Corrosion Resistance	ASTM B117 – 11	Standard Practice for Operating Salt Spray (Fog) Apparatus
	IEC 60068 – 2 – 52:1996	Environmental testing – Part 2: Tests – Test Kb: Salt mist, cyclic (sodium, chloride solution)
Seismic	IEEE 693	Recommended Practice for Seismic Design of Substations – Section 8: Seismic Performance Criteria for Electrical Substation Equipment

Table 9: Mechanical and Other Standards

System and Equipment Modelling

The services provided by the Modular Power Flow Control is very varied and consequently the ranges of studies and models are also varied to permit these services to be evaluated. A high level of summary and guidance for the more frequent applications is provided in this section.

In order to perform these studies Modular Power Flow Control providers generally provide both steady state, dynamic and EMT models.

The historical main use of Power Flow Control Devices is to direct power flow to avoid overloading of network equipment ratings, whether they be overhead lines, cables, transformers or other substation equipment. This could be pre or post contingency. This type of network modelling study is a steady state analysis. The application of Modular Power Flow Control device is to change the relative impedance of the circuit or transformers to alleviate an overload by redirecting power into other pathways.

For a single issue, this can be done simply done manually or through automated routines directly changing the circuit impedances until the problem is resolved or adding in additional impedance in the form of a capacitor or reactor in series with the circuit (or alternatively a more sophisticated Modular Power Flow Control model). The equivalent impedance calculated can then be used to define the number of modular units required.

For multiple issues the same approach can be used, but it is often more efficient to use more automated operational optimization techniques [22]. These techniques use interacting capability of the devices to alleviate local regional overloading at number of points in a grid and by doing minimize the overall number of devices that must be deployed.

Procurement

The following should be read in conjunction with those general recommendations already provided.

Tendering Specification Recommendations

Modular Power Flow Control is a rapidly developing technological space, with new customers experiencing the technology generally for the first time. This has been a cause for delay in many instances, as customer technical specifications typically are developed with use and experience.

The key technical specifications for Modular Power Flow Control selection are relatively simplistic. The operating conditions normally required for tendering of other plant and equipment operating as part of the main grid are a primary requirement to be specified. These include the connecting voltage, maximum continuous current, maximum short overload current, maximum fault current (single and three phase). In addition to this are power quality, EMC and noise requirements, and the standards and parameters that the customer uses for these.

In addition, functional requirements should be provided. These include the overall availability of the devices (as there are many options to achieve this), the impedance that deployment should be able to provide, and the space constraints that exist in the station[s] or route corridor[s] that the devices will be installed. Many of these functional requirements would be best discussed or worked on collaboratively and typically, suppliers would work with system operators to guide and inform these choices.

The use of appropriate standards is standard procurement requirement and can be a cause of difficulty in tenders due to the natural delay in technology specific standards recommendations from the industry standard organizations like of IEC, ANSI or IEEE. In the preceding technical assurance chapter above a list of equivalent standards are provided and are recommended to be used.

Typical Lead-time for Deployment

In advance of carrying out the deployment of Modular Power Flow Control (MPFC) devices, the deployment layout and design should be completed and approved by the relevant parties. This takes roughly 6 months.

There are many technical details and records of activities preformed as part of the construction and installation process. The construction process can be summarized as:

- Shipment of equipment to site.
- Pre-installation on site evaluation and equipment check.
- Preparation of foundations.
- Preparation of connection into network (overhead line/busbar) configuration.
- Assembly of steel support structures.
- Assembly of Modular Power Flow Control devices into their support structures.
- Assembly and connection of cabling and busbars between Modular Power Flow Control Devices.
- Assembly and connection of Communication equipment.
- Installation.

Recommended CBA methodology

Modular Power Flow Control should follow the generic CBA methodology in the general requirements in the preceding chapter, but with the following additional elements as applicable.

Modular power flow control has the potential for a number of uses e.g. overloading of network elements, voltage management, oscillation damping, etc. As well as the primary need driving the initial investment, the current or future network needs from added benefits should be considered by the system operator and their annualized benefit included into the CBA.

Example cases

UKPN ‘Loadshare’ project

The DNO is committed to facilitate the connection of renewable generators in an economic and reliable manner to enable the transition to a low carbon future [23]. A constraint was identified on the 132 kV network in Essex between two substations (Lawford Grid and Bramford) which was delaying the connection of renewable generators on the local network. Traditional solutions to add additional network capacity include increasing operating temperature with infringement clearance works, reconductoring existing lines or building new circuits. These approaches are often quite costly and require significant time and resources to engage appropriate stakeholders, plan, secure requisite system outages and construct. They are also intrusive to local communities and environmentally protected areas. Given that the 132 kV network between Lawford and Bramford is a meshed network, with three circuits of varying impedance operating in parallel, the DNO investigated a power flow control solution as an alternative option. Analyzing historical line flows and today's constraints, it was identified that there was potential to utilize power flow controllers to solve the constraint and release capacity for future generators. Upon investigation, it was determined that the impedance of the three parallel circuits was not evenly balanced. An adjustment of the impedance - through change in Reactance (X), or phase Angle (δ) - on one circuit changes the ratio of impedance between the three circuits, resulting in power flow changes on the individual circuits as described in the equation below.

$P = V1V2 \sin\delta / X$

Where:
P = Active power transmitted
V1 = Line-to-line voltage at sending end
V2 = Line-to-line voltage at receiving end
X = Reactance of circuit
δ = Angle of V1 with respect to V2

The DNO assessed all forms of power flow control as possible solutions. In order to deliver the optimal level of constraint relief and load sharing on the three circuits, it was determined that a fine-tuned power flow controller was required on two of the three parallel circuits. Traditional power flow controllers such as phase shift transformers and series reactors were considered, but costs, spatial constraints, timing and lack of discrete, real-time controllability meant that a more modular and discrete option was required. The exact network configuration is shown in Figure 8 for reference.

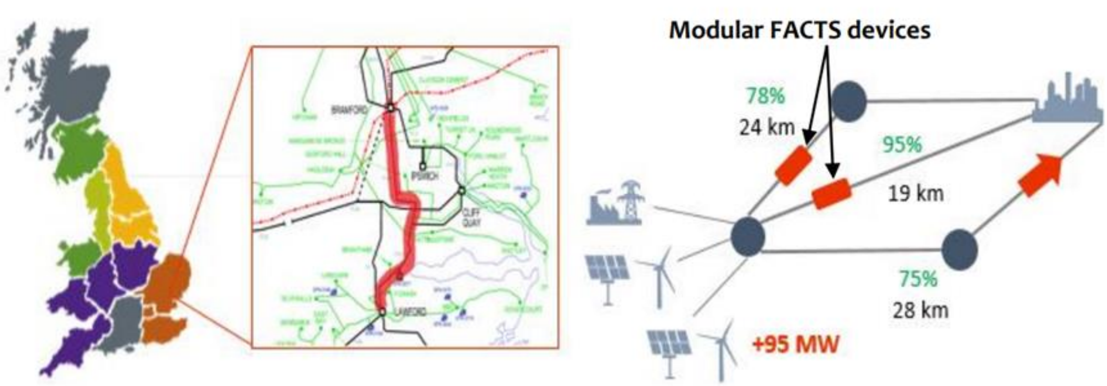

Figure 10: Modular Power Flow Control in UK on two 132 kV circuits delivering 95MW of additional capacity

Horizon Europe Project - Farcross

The Farcross project considered the ability of Modular Power Flow Control to improve interconnection capacities.

After considering four lines situated in Northern Greece chosen in order to observe the impact on the interconnection line between Greece and Bulgaria, and Nea Santa substation was selected. The studies that were completed in this process followed the type of load flow modelling described in the equipment and system modelling approach, to find the lines most restricted due to their limited line rated capacity (MW rating). These lines represent the weak links in the network that would constrain the amount of power that can flow through the network before it becomes overloaded. The Nea Santa-Lasmos transmission line, offered the second highest level of impact from a Modular Power Flow Controller deployment, and the station was ideally suited to locate the equipment.

Figure 11: Top view of the Nea Santa Substation

It showed that its remote location would allow for easy transportation of the required large equipment and offer sufficient installation space with no social acceptance issues. Following IPTO's impact analysis, the installation in Nea Santa substation was determined to have positive impact on nearby renewable energy integration and the cross-border capacity between Greece – Bulgaria and Greece – Turkey.

Consequently, the Nea Santa substation is an ideal installation location, as shown in Figure 11.

Figure 12: Nea Santa – Lasmos line on map and its loading

Monitoring Sensors

High Level Description of technology

From an environmental perspective, the widespread to effectively monitor, control, and regulate a power grid, a balance between the generation and consumption of active and reactive power is essential. Achieving this balance requires accurate measurements of voltage, current, and frequency, as defined by the power equation.

Since medium and high voltage, as well as current levels, cannot be directly connected to measurement devices, transducers are necessary. These transducers can be realized using various measurement principles. However, conventional voltage and current transformers are resource-intensive, heavy, bulky, and expensive.

In the context of a smart grid, the digitalization of substations, particularly at the medium-voltage level, is critical. A general guideline suggests that for every 100 households, one substation or ring-main unit (RMU) is required. With over 2 billion households globally, this equates to approximately 20 million RMUs. Digitalizing a single RMU requires around 15 sensors or conventional devices. If 20–50% of these are to be upgraded, this translates to a demand for 60–150 million devices. This production scale necessitates significant resource availability and energy supply to power these measurement points.

This is where non-conventional instrument transformers, also referred to as sensors or LPITs, play a transformative role. These sensors use up to 80% fewer resources, cost approximately 30-50% less, and are compact, lightweight, and easy to install. They are also energy-efficient, requiring about 70% less power than traditional transformers. The underlying measurement principles for these sensors are mature and reliable, with products already deployed globally, achieving a Technology Readiness Level (TRL) of 9.

Compared to conventional transformers, sensors exhibit superior performance in high-frequency behaviour. While conventional products are typically designed to measure up to 500 Hz (as stipulated in several IEC standards), sensors can measure frequencies up to 20 kHz and beyond, depending on the product. This capability is critical for monitoring power quality and harmonics, especially with the increasing integration of inverter-based resources into the grid. In this context, sensors are the only viable option for transducers.

Adoption of sensors offers significant benefits. The substantial resource savings achieved by using sensors align with the growing need for sustainable grid technologies. Technically, sensors not only meet but exceed the specifications of conventional transformers, delivering enhanced performance at lower cost. This makes them an indispensable component in the modernization of power grids.

Non-conventional low power voltage measurement (LPVT):

LVPTs for example utilize an ohmic-capacitive voltage divider with the principle of a normal voltage divider. By splitting up the primary voltage with several resistors and capacitances, the secondary voltage is generated. Here secondary voltages of customer specified value in a low voltage range can be achieved by using the ratio between resistors and capacitances. In standards, the general output voltage of 3.25V/√3 is stated but can be easily changed to customer specifications.

Figure 14: Current Sensor with split-core by Greenwood-Power

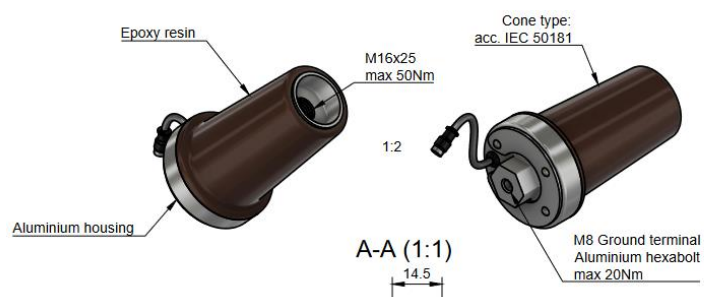

Figure 13: Voltage Sensor by Greenwood-Power

Non-conventional low power current transformers (LPCT):

In the case of LPCTs, also called current sensors, inductive current generation is applied; however, this current is further transformed into an output voltage. Here with the usage of a shunt-resistor at the output of the product a completely different output value, namely a voltage instead of a current, is achieved.

The integration of the shunt-resistor allows a smaller number of turns, which are transformed with the value of the shunt resistor to the output voltage required by the customer.

Recommended technology risk management

Since LPVTs and LPCTs transform the voltage and current into values that are way smaller than their conventional counterparts, the product itself is very safe during installation. Here, no field engineer can be hurt if a short circuit of the current measurement is forgotten. They are also easy to deploy due to their small and lightweight design. When designing the measurement chain, however, the right measurement or protection devices should be utilized. As the secondary outputs of the products are different, still many devices on the market have not adapted to those input signals. With a wrong measurement device, the LPVT or LPCT is not compatible to, the complete measurement or protection chain is useless and must be redesigned. For this reason, reading technical datasheets and getting in contact with the companies supplying the measurement equipment and sensors is a prerequisite.

Procurement

Tendering Specification Recommendations

All non-conventional products only include passive components in their design, so once they are ordered their lifespan is decreasing even when only in storage before deployment. In addition, they do not need any updates or an additional power supply, making them a plug-and-play product for system operators. With passive components, the lifespan once employed in the power grid is around 30 years, in line with the standard devices in the power grid.

As already mentioned, the output voltages of the devices are quite different when compared to conventional products. This means if non-conventional products should be applied in a tender, also the measurement device after the transducer will have to fit accordingly. From technical perspective the input burden and voltage level as well as connecting cable length must be made known to the transducer manufacturer since the product is adjusted for every measurement device and application case specifically.

Specific type test

As many electric products, sensors have to be tested according to standards. For non-conventional voltage and current transformers applies IEC 61869-1, -6, -10, -11. Accordingly, lightning-impulse tests as well as partial discharge tests are the most important test of the product. Provided the product passes this test, it is technically safe and can withstand overvoltages in the systems without any problems. It makes no sense to apply the cable test standard in which sensors are tested in boiling water above 100 degrees, as this is not a condition that occurs in reality.

Typical process stages and timelines for deployment

The type and process of product deployment depends strongly on the application. Sensor can be designed for use in air-insulated switchgear as well as air-insulated switchgear or pole mounted solutions. Normally once the equipment is chosen and paid for, delivery times for the sensor equipment are around 2 month and can then be directly installed.

Example Cases

Already installed equipment

In these cases, sensors must be able to be added as retrofit solution. Since the dimensions of switchgear or poles are already in operation, changing those to adapt to additional measurement gear is not feasible. Here the customer looks for the smallest products on the market that can be added without cutting open cable connections.

Switchgear application

For switchgears, normally the customer already has a manufacturer for it and wants to add the measurement gear. In cooperation with the sensor manufacturer, the customer can choose a measurement device and sensor for his voltage level. Depending on the sensor manufacturer, special installations are possible, but generally, in gas-insulated switchgear the voltage sensor is of cone type for installation inside a tee connector. Here C-shape as well as shapes for asymmetrical tee connectors are standard. For current sensors a ring type sensor with a full or split-able core are utilized, which are installed directly around the cables. For air-insulated switchgear, voltage measurements can be combined with supporting insulators, where the voltage sensor is manufactured as supporting insulator making it a 2-for-1 product. For current sensors, a measurement on an uninsulated busbar is not possible.

Pole applications

Here the main application is an insulator put either directly on the overhead line or on a supporting beam. New generation products can measure voltage and current in one product can transmit those signal values to the measurement device. From there the analog signals are converted into digital ones and then further processed to SCADA systems or cloud-based solutions. In addition, here the system operator has an initial concept and based on it the sensor is integrated, certified with pilot installations and then rolled out into series installation.

CBA methods for this technology

The easiest way to evaluate this technology is not by strictly comparing conventional technologies to non-conventional technologies but by looking at the complete measurement chain. As the measurement or protection device plays an important role and has to fulfil certain criteria not only the sensor has to fit the application but also the measurement device and then the sensor to the measurement device. When comparing the two technologies directly to each other non-conventional products are often more than 30 percent less expansive and do not require additional space in applications. Since space is also an important factor there are now more variables to consider, as well as when thinking about the energy-efficiency the power consumption of the product. Here non-conventional technologies also beat conventional technology.

Example cases of deployment

As market adoption always includes a mindset or political change and conventional products are well known and used in the energy sector, the adaption of sensors is still slow compared to the need of digitalization.

Saudi Arabia

One of the countries with the most installed sensors is Saudi Arabia. Between 2019 and 2023, more than 150 000 sensors were installed in different kind of switchgears. Here the main use case is measurement for active and reactive power calculation as well as harmonic detection.

Europe

Energy transition in Europe is picking up speed and the market change in the sensor market is visible. With most measurement and protection device manufacturers, including sensor inputs in their devices also sales in all over Europe is steadily increasing. Now over 100 000 sensors are installed in different switchgears as well as on pole installations.

High Temperature Superconducting (HTS) cable systems

High Level Description of technology

Superconducting cables use superconducting wire instead of copper or aluminum to transmit power. Superconducting wire has a much higher current density than copper or aluminum. A superconducting wire can carry 250-600 times the level of current that the same sized copper wire can carry.

Superconductivity is a quantum mechanical phenomenon where a material can conduct electricity with zero resistance when cooled below a certain critical temperature. This unique property allows for highly efficient power transmission, as there are no energy losses due to resistance.

High Temperature Superconducting (HTS) cable systems typically transport three to five times higher currents than traditional cables with lower losses, thus improving the overall efficiency of the power grid and contributing to lower CO2 emissions. One of the most significant advantages of HTS cables is that they are more compact than traditional cables due to their ability to carry higher currents at lower voltages and hence in a smaller cross-sectional area. This compactness allows for easier installation and reduces the need for extensive trenching and civil works, which can be both costly and disruptive especially in urban or environmentally sensitive areas. Moving power at lower voltages also has the benefit of eliminating the need to build out a high voltage network in an urban environment.

To maintain superconductivity, HTS cables operate at very low temperatures using Cryo-cooling units that supply and circulate liquid nitrogen. The choice of superconducting material determines the choice between helium and nitrogen, depending on the superconducting material used.

The HTS system integrates the HTS cable, electrical junctions and terminations, and a Cryo-cooling system. HTS Cables can be provided either for AC or DC power and in High-voltage, Medium and Low-voltage networks.

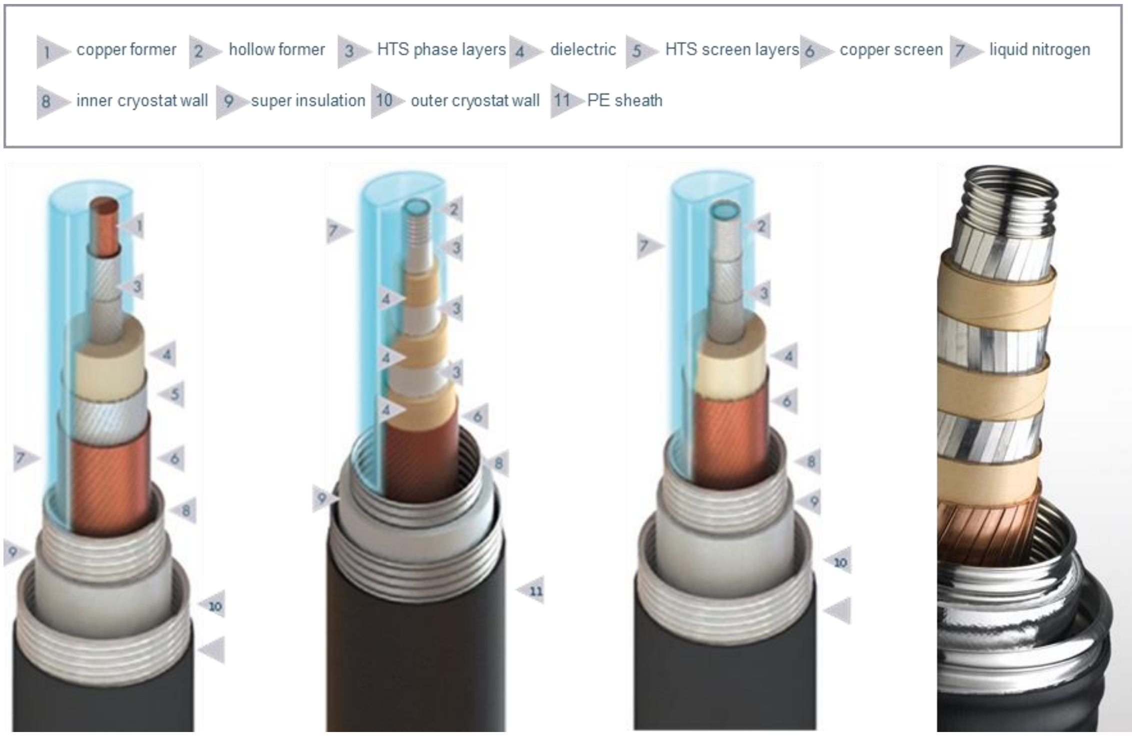

Figure 15: Components in a typical Superconductor

Technical Readiness

At the time of writing, more than 11,000m of Superconducting cables have been installed throughout the world in over 15 locations across the last 15 years. This solution is readily available and well proven, therefore TRL9 would be applicable (depending on the individual manufacturer's development path).

Figure 16: Photos of Superconductor deployments

Installations: Long Island Power Authority, USA – COMED, USA – SNCF, France – RWE, Germany

Applicable standards

The following are the applicable standards relating specifically to Superconducting cables:

Standard	Comment
IEC 63075:2019	This standard specifies test methods and requirements for high-temperature superconducting (HTS) AC power cable systems, cables and their accessories, for fixed installations, for rated voltages from 6 kV (Um = 7,2 kV) up to and including 500 kV (Um = 550 kV). The requirements apply to single-core, three-core and three-phase concentric cables with cold dielectric and their accessories that are not intended for fault current limitation purposes.

Table 11: Applicable Standards for Superconductors

Benefits of HTS cables

- HTS cables have virtually zero ohmic resistance and can transmit high power at much lower voltages than traditional cables. For example, a 10KV HTS cable can transmit 40MVA. Using HTS to transmit high power at lower voltages avoids the need for costly voltage upgrades in substations, the expense and right-of-way challenges of an MV or HV cable, and the need for transformers.
- HTS cables do not generate any thermal or electromagnetic impact and can be installed in very narrow passages close to any type of network. They allow installation of high capacity while minimizing land usage, civil works and nuisances for the neighborhood.
- Compactness: High current carrying capacity allows for smaller and lighter cables for the same power transmission compared to traditional cables. The technology allows operators to use the existing infrastructure for powering up the grid and / or making it more resilient e.g. back-up interconnection of 2 sub-stations – see REG case study below.
- High Current Density: Superconducting cables carry much higher currents compared to conventional copper or aluminum cables of the same size. The combination of compactness and high current density allows for the optimization of rights-of-way while dramatically reducing construction and civil costs.
- Zero Electrical Resistance: When cooled below their critical temperature, superconducting materials allow electricity to flow without any energy loss. They can transmit electricity over long distances with minimal loss, making power grids more efficient.
- Recommended Use Cases: Urban distribution grids, data center interconnection, renewable generation interconnection, EV fleet charging infrastructure & the offshore grid.

Recommended technology risk management

HTS Cable systems use the same asset management and maintenance procedures as traditional cables for the hardware part of the system (the cable). It is important to note that HTS cable systems use a cooling plant which is a dynamic system that requires a standard maintenance procedure like any cooling system.

Because HTS cables operate at a stable low temperature they are less susceptible to wear and tear over their lifetime caused by thermal cycling of traditional cables.

The cryogenic side of HTS cables introduces maintenance practices new to utilities, however these leverage decades of industrial experience working with liquid nitrogen systems. These systems are comprised of refrigeration systems, pumps, and fans and utilize noncomplex control systems.

Supply Chain Risks are an issue for the electricity sector. For HTS cables two principal supply chain risks can be noted: the availability of HTS wire and the cryocooler plant lead-time.

The HTS wire industry has recently scaled up global production driven by significant investment in the magnetic confinement fusion industry which requires large quantities of high quality, low cost HTS wires. This growth has accelerated the industrialization of HTS manufacturing. Today there is global capacity to manufacture 11,000km per year and this capacity is scaling rapidly. For example, MetOx International, a US based manufacturer of HTS was recently awarded a $80M grant by the Department of Energy to build a 5,000km plant which is expected to come on stream by the end of 2026. In addition to securing supply of HTS for cable manufacturers, this level of industrialization is reducing the cost of HTS. As costs reduce the number of projects where HTS has a positive cost benefit outcome for utilities compared to traditional technologies is growing substantially.

For the Cryocooler plant, 4 main system suppliers are based in Europe and have developed industrial systems which are used in liquefaction plant systems and on LNG tankers. The current capacity of those manufacturers in Europe is in line with the current market demand, industrialized and easily scalable. The main market orientation lead by the HTS Cable OEM is to standardize those systems to reduce the engineering and system integration risks.

In summary, superconducting cables represent a significant advancement in electrical engineering, offering unparalleled efficiency and performance in power transmission and other applications, albeit with considerable technical and economic challenges.

Amidst the growing demand for energy, and especially as the shift from fossil fuels to electricity continues, developing and adapting the existing electrical networks will require new technologies and approaches. For instance, in densely populated areas filled with multiple power grids, as well as telecom and pipe networks, bringing additional power may be very costly and challenging. To address this issue, HTS Cable systems can replace or be added to traditional copper or aluminum cables, be simply laid down into existing spare ducts and avoiding any civil works requirement and improve the grid resilience while being used as an underground grid solution.

Recommended Technical Assurance Process

For utilities considering the use of HTS for the first time technology risk management can be managed by exercising some or all the following steps with the support of HTS cable suppliers:

1. Using the IEC 63075 standard, defining the HTS AC Cable standard.
2. Review of cable system specifications which are usually based on conventional cable technologies and adapting them to the specificity of HTS technology.
3. Defining a Type Test report which will ensure the HTS Cable and accessories compliance to the defined test and project performance expectations.
4. Integrating the conventional specs and norms for MV and HV Cables as a guidance for the HTS cable systems.
5. Understanding how HTS technology works and the best use cases for it - including benefits compared to conventional solutions.
6. Benefiting from the experience of other utilities who have installed HTS.
7. Reviewing reports published by well recognized bodies such as CIGRE and IEEE.
8. Understanding how best to evaluate the costs and benefits and particularly how to compare HTS cable solutions to copper/aluminum solutions.
9. Modelling HTS cables in planning and operations studies.
10. Learning about asset management related issues from OEMS and experienced users including installation, maintenance, spares requirements, reliability, operations, OEM support

System and Equipment Modelling

HTS cables can be modelled in existing load flow software packages. They are modelled the same way as conventional cables, however they have different R, L, C parameters which will be provided by the cable OEM.

Procurement

HTS cables are manufactured by leading cable suppliers such as Nexans, NKT, LS cables.

Most utilities have experience procuring equipment from one or more of these companies making the procurement process straightforward.

Based on the current HTS Cable technology adoption, it is important to identify specific projects for which the conventional cable technologies cannot be applied or would be too complex and/or costly which shall ensure the plain benefit of the HTS technology from the users.

Tendering Specification Recommendations

HTS functional and technical specifications are similar to traditional cable specifications albeit operating at higher capacity. Tendering specifications shall be made based on the required System MVA, expected operability rate of the system and the fault conditions.

OEMs can provide support to utilities to identify the level of redundancy required in the overall system including the cooling systems and how to account for this in specification documents.

Typical Lead-time for Deployment

Manufacturing of HTS cables takes place in existing cable manufacturing facilities and does not require construction of new facilities. The current cable OEM industrial manufacturing capacity exceeds market demand.

Manufacturing and delivery lead times are in the order of 12-24 months depending on cable length. Installation of HTS cables, joints, terminations and substation equipment is similar to those of other standard cable installations.

HTS cables require much smaller trenches and rights of way than the equivalent capacity copper/aluminum cables accelerating installation and permitting time (HTS cables have no thermal or EMF spacing requirements).

Recommended CBA methodology

CBA should include evaluation of the HTS benefits including:

- Faster and lower cost permitting due to smaller rights of way.
- Smaller installation costs due to smaller cable trenches.
- The reuse of existing ducts is often possible and should be priced accordingly, reducing the installation costs. Reinforcing a network at 110kV with traditional cables may require a new cable route, whereas an equivalent capacity HTS at 20-33kV may be able to use existing cable ducts.
- Lower lifetime operational losses.

- Operating at lower voltage than the equivalent capacity traditional cable will yield substation construction, permitting, transformer and switchgear savings which should be evaluated.
- Speed of delivery. The HTS project, being at lower voltage, is likely to be completed sooner than the alternative yielding earlier benefits e.g. reducing congestion or connecting new demand/generation sources. The value of early completion should be included in the CBA.

Example projects

There are more than 15 utility projects completed globally. The following list details 3 projects that highlight a range of project voltages, benefits, and locations. Information on two additional projects in construction is also provided.

2013 Nexans/RWE Ampacity Project, Essen Germany: 10kV 2,300 Amps, 40MVA

Alternative to conventional 110kV transmission line

Project involved installation of a 10kV 40MVA 1km HTS Cable in Essen Germany in 2013. The HTS project was an alternative to installing a 110kV cable, building out a 110kV side to an existing 10kV substation and avoided the need for HV/MV transformers in the city centre by connecting city centre grid from a substation in urban fringe

2021 Com-Edison/Nexans, Chicago USA 12kV 3,000Amps 62MVA

Resiliency Project

This project was executed as part of a US Government Department of Homeland Security initiative to secure the U.S. grid against extreme weather and other catastrophic events including cyber security risks. The HTS Project links two 12kV substations with a 12kV 3,000 A cable to provide redundancy in the event of loss of supply to one of the substations.

2019 KEPCO/LS Cables, Korea 23kV 50MVA 2,400Amps Shinghal Project

Alternative to 154kV

The HTS project replaced a planned project involving a new 154 kV cable with associated transformer and substation works by connecting two substations at 23 kV with high-capacity 1 km triaxial HTS cable. It was successfully commissioned in 2019.

In construction phase

2024 SNCF/Nexans, Paris France 1.5 kV 3,500 Amps DC Project

Alternative to 12 Copper Cables at same Voltage

Montparnasse train station requires additional power but there was no way to get the power cables into the station. Existing cables were piped through an 18th century bridge. There were 3 spare pipes but 24 were required to deliver the capacity using CU cables. Nexans are supplying two 3,500 A 1500V DC cables to carry the same amount of power making the project feasible

2024/5 Stadtwerke München Infrastruktur/NKT Superlink Project, Munich, Germany 110 kV 500MVA 2,600 Amps

This project is completing phase 1 trialling within the substation with construction of a 15km cable due to be kicked off in 2025. Once completed, this will be the world's longest HTS cable in service. The 15-kilometre 110kV cable will connect Menzing and the southern energy site in Sendling. This project will enhance the sustainability and climate-friendliness of SWM Infrastruktur's power grid.

Innovative Software Solutions for Grid Optimization

High Level Description of technology

Grid Optimization is a mature solution that has been around for a long time, especially on the high voltage electricity transmission level. The balancing of the energy system, energy re-dispatch, congestion management and function such as optimal power flows and security constrained economic dispatch is used to optimize various aspects of the system.

The traditional systems that fall into this category includes software such as Energy Management Systems (EMS), and Advanced Distribution Management Systems (ADMS) are already market available. EMS focuses on large-scale energy generation and distribution optimization, while ADMS is designed for improving visibility, control, and automation in distribution networks. As the energy systems transition towards smarter, more efficient, and sustainable models, these systems start reaching their limits. They are often being built on traditional Operational Technology (OT) platforms, deployed in on-premises hardware, with monolithic designs making them heavy to upgrade and evolve. However, for all innovative technologies below, the ADMS system can natively include one or several, and/or integrate with systems providing these new capabilities to form a comprehensive grid optimization system.

What can be considered as new and innovative optimization solutions, includes both transposing traditional optimization functions from the transmission grid to lower voltage levels, as well as introducing new technologies that increases our ability to optimize and operate the grid closer to the ideal state. Innovative grid optimization software provides utilities and operators with the ability to manage increasingly complex networks, integrate renewable energy sources, and maintain a reliable service.

Innovative software for grid optimization is designed to enhance the efficiency, stability, and scalability of electricity grids. These solutions allow grid operators to better balance supply and demand, integrate renewable energy sources, and reduce operational costs. They typically utilize artificial intelligence (AI), machine learning (ML), and advanced analytics to predict grid behaviour, automate decision-making, and respond in real-time to fluctuations in energy supply and demand. They can be delivered as cloud-based services, resource efficient, fast to deploy and easy to maintain.

The category of innovative software solutions for grid optimization is broad but can be layered into three key capabilities: Visibility, Analytics and Control.

Grid Visibility

Low voltage visibility solutions allow DSOs to monitor and visualize what is happening in their low voltage electricity grids by combining data from multiple sources and generating operational analytics insights into the state of the grid, for example power quality, outages, losses, fraud and congestion forecasts. Low voltage visibility is sometimes referred to as the ability to see into the secondary substation level by retrofitting monitoring equipment on a station or feeder level, or deploying smart substations. Full low voltage visibility also includes the customer smart meter data which is becoming more and more relevant with the roll-out of secondary generation smart meters. By combining smart meter data with network topology, asset data and substation monitoring data the DSO can see into their low voltage network where they have previously been blind.

The ambition of low voltage visibility solutions is to be close to real time, but this is still not a realistic scenario for most DSOs. Even though the sampling rate of smart meters can be as low as 5 minutes, latency of receiving the data is often significant (> hours). As this latency is reduced with better communication solutions, it will enable real time insights down to low voltage which is critical to monitor and detect grid constraints in real time and enable real time congestion management.

To add additional visibility "behind-the-meter" of grid customers, DERMS solutions can be added to communicate directly with IoT devices that are outside the reach of the DSO communication systems. This visibility of the grid edge usually requires customers to opt-in to being monitored in exchange for receiving energy optimization or cost minimization services.

The maturity of low voltage monitoring is between TRL7-9 where the less maturity solutions reflect low latency, high granularity data sources.

Figure 17: Low voltage monitoring and overload detection

Grid Analytics

The general concept of digital twins has already been described in previous sections as TRL 9 and can be implemented on different levels in the energy system to enhance the level of grid analytics. In the context of grid optimization, the concept of a Digital Twin specifically refers to the comprehensive modelling of the network on an electrical level, not on a detailed device level. Also, while both ADMS and digital twins play roles in managing and optimizing power systems, ADMS is a comprehensive software platform focused on real-time control and management of distribution networks, while a digital twin is a dynamic and detailed virtual representation of the entire power grid that incorporates real-time data and simulations for analysis and decision-making.

A subset of grid analytics aims to optimize the capacity of electricity networks Capacity analytics, which is becoming increasingly important due to the energy transition. The core of capacity analytics is power flow simulations, and the application can be for the planning domain, such as Distribution Network Development Plans (DNDP) and new grid connections or in the operational domain such as congestion and voltage management or integrated analytics to optimize grid performance, minimize losses or balance the grid. The planning analytics is moving to a more granular level into low voltage feeders to manage for example increasing connection requests from rooftop solar. Also, the large infeed of new connection requests requires more automation and faster processing including decision support and automatic proposals of how to enable a new connection in areas with limited capacity. For operational

analytics, power flow performance in large network of millions of nodes, and potentially poor data quality, is necessary.
The maturity of analytics for planning purposes can be considered TRL 9 with mature solutions with strong process support. Several countries and DSOs have published capacity heat maps on local and national level and the DNDPs is driving deployment of more technology. What is holding back broad adoption is the availability of data from both a quality and integrity perspective.

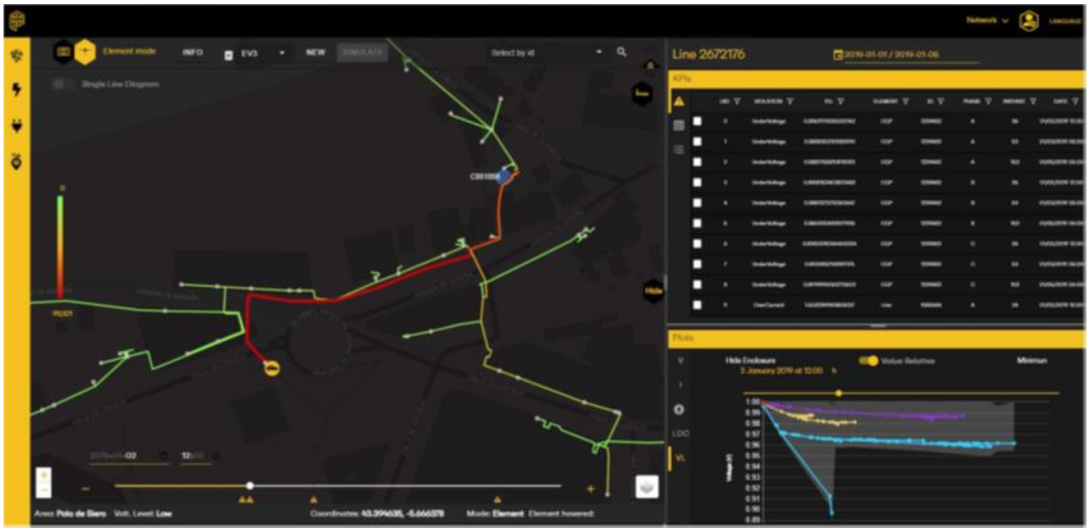

Figure 18: Dimensioning flexible grid connections when grid capacity is limited

To enable grid analytics when data quality is poor or data is scarce, AI based analytics tools are emerging. These tools can be both faster do deploy and have high operational performance. They employ machine learning algorithms and do require historical datasets to train on. AI based grid analytics tools have been piloted for both hosting capacity and flexibility management applications, for example in Oceania. In Europe they are less common, and the maturity is TRL 6-7 since few larger demonstration projects have been implemented. AI is also extensively used for forecasting time series data as input to grid analytics algorithms, but in this case the pure AI forecasting can be considered a mature and established technology and not a subject for this paper.

Traditionally the operational risk in electricity grids have been limited by designing the grid with high safety margins, using N-1 to ensure the grid can still operate in case of failure of key components. With increased visibility and control this way of dimensioning is being challenged and the potential of releasing grid capacity by running the grid closer to its limits, taking on additional evaluated risks, is large. Dynamic risk assessment solutions are being developed, which work with asset risks and aggregate these on a system level to keep the grid operator informed in real time about risk levels. In situations or low-risk the N-1 criteria could for example be relaxed to an N-x criteria where x< 1. Risk based software solutions have relatively low maturity, TRL5-6.

Control

Software based grid control solutions include ways of controlling existing grid connected assets without the need to deploy large volumes of hardware or control devices in the field. This section will focus on how DSOs can get access to previously not controllable assets, primarily customer owned to optimize overall grid performance. Having visibility and analytics to detect and predict bottlenecks, voltage issues and increased risk, the controllability adds the means to mitigate and solve these problems.

Control could be explicit (how much, for how long) or implicit (providing a range or a max profile) and direct (send a control signal) or indirect (send a price signal driving customer behaviour). There are many different emerging control methodologies with different combinations of these control types across countries and regions. The software solutions enabling these are described here.

Local capacity markets are an example of explicit and indirect control methods. These are traditional market platforms applied in a new context which is highly local and with assets and services on a granular level and bid sizes down to 1 kW. The technology is mature in general since it has been used for TSO markets and is also already deployed widely in some countries like the UK on a DSO level. However, there are factors that complicate the interoperability and operation of the DSO markets. The characteristics of local capacity constraints require that the customer (DSO), the market platform and the suppliers (aggregators and other service providers) are always aware of the electrical connectivity of assets which is changing with grid switching. The calculation of baseline to evaluate activation response is still evolving. And the need for tools to coordinate between TSO, DSO and service providers is still on a design stage. The end-to-end process and software solutions for scalable market-based capacity management is therefore much lower, on TRL 4-5.

Implicit and direct control methods are useful when the exact behaviour of an asset is not important but there is a need to make sure critical limits are not passed. Distributing dynamic load and generation profiles to customers is a way of giving a max load and max generation range within which the asset can operate freely. These solutions are sometimes referred to as Dynamic Operating Envelopes (DOEs) and are using standardized communication protocols to publish DOEs to aggregators or smart devices such as solar inverters. Software generating DOEs rely on both grid analytics and forecasting algorithms to calculate the profiles on a rolling time ahead horizon, for example 24 hours ahead. DOEs can be a better option than markets in lower voltage levels where market liquidity is naturally low, for example solving voltage constraints on a secondary substation level. DOEs trials and demonstration projects are common while a few larger scale rollouts have been accomplished, suggesting a maturity level of TRL 7.

Figure 19: Behind-the-meter asset control

Explicit and direct control methods are possible to implement when the DSO have a direct contract with the end customer that allows for control, such as procured bilateral agreements, non-firm connections or opt-in programs such as traditional Demand Response. Communicating with end devices is mature technology, however the application of controlling thousands of devices behind-the-meter require the need for protocol standardization, managing communication failures, device failures and bad forecasts. DERMS software managing this last mile communication and control is widely deployed for a number of use-cases but are evolving fast to cover more advanced and complex situations, assets and control mechanisms.

Finally, local control systems like microgrid controllers, community control systems or home energy management systems play a role in contributing to grid optimization. They solve local issues and prevent problems from propagating from local level to system level. They have not been considered in this paper since the technology is often similar to the large scale systems, only adapted to a smaller system size with more local automation and hardware-based solutions.

Communications

Effective communication is vital for grid optimization software to perform real-time monitoring and control. While the traditional systems could rely on real-time data from a limited number of data points in the grid, the new reality requires the ability to work with a multitude of signals which are both less reliable and more diverse. The concept of real time also needs to be managed since a lot of the data, like smart meter data, is not using communication solutions designed to collect in real time. And if they were, the amount of data collected would be extremely large and expensive to store and manage. Near real time is a relative term that can be used to describe the level of data latency that a specific application requires to perform its task and could stretch from minutes to hours or even days.

Moving optimization functionality to lower voltage levels would not be efficient if all devices had to be connected using fibre optics and dedicated measurement equipment. Instead, low voltage and DER data is often collected via public internet or radio including Internet of Things (IoT) devices, smart sensors, and smart meters. These technologies gather critical data on energy flows, voltage levels, and system performance. Moreover, the integration of 5G technology promises to further enhance grid communication, offering higher speeds, lower latency, and better connectivity for distributed assets like solar panels, wind farms, and EV charging stations.

With more measurement and control devices in the field, using standardized communication protocols are key to ensuring interoperability, secure and efficient systems.

The IEC 61850 standard is commonly used for communication in substation automation, ensuring interoperability between different devices and systems. It operates on a local area network (LAN). Advanced grid software integrates with this standard, allowing secure, fast, and scalable communication across the grid. It is suitable for environments requiring high-speed, real-time communication between devices in substations, such as transformers, circuit breakers, and relays.

For managing demand side flexibility and communicate via aggregators as well as directly with assets both in front and behind the meter application protocols such as OpenADR and IEC2030.5 are becoming the global standards. These protocols operate over wide-area networks (WAN), allowing utilities to send signals to many distributed devices over the internet. It supports asynchronous, event-based communication, which doesn't require real-time speeds but is suitable for demand response applications.

OCPP is specifically designed to communicate with charging infrastructure. While OpenADR and IEE2030.5 are designed to work with any type of controllable device OCPP is more specialized which makes it more suitable for communication between an aggregator or service provider ad the end device, whereas the central system communication with the aggregator should use a more comprehensive protocol. This approach will reduce the complexity of the central optimisation system and limit the communication interfaces it has to support.

Recommended Technology Risk Management

Managing technology risks in grid optimization is critical due to the interconnected nature of energy networks and the fact that optimization is usually a mission critical function. Recommended approaches to technology risk management include:

1. Cybersecurity: Grid software must be resilient against cyberattacks. Solutions should comply with standards like ISO 27001 for information security management and incorporate advanced encryption and intrusion detection systems. Cloud deployed software can reap the benefits of state-of-the-art security infrastructure including physical security of data centres, monitoring tools, access control and endpoint protection.
2. Redundancy and Failover Mechanisms: Software should have built-in redundancy and automatic failover to ensure continuous operation during hardware or network failures. In modern, cloud hosted software solutions the cloud hosting environment natively supports these capabilities. While the traditional systems relied on redundant physical hardware which had to be geographically separated, the cloud infrastructure can seamlessly fail-over to another datacentre and supports horizontal scaling where multiple nodes can be deployed to share load or take over the software operation.
3. Scalability: Futureproofing through scalable architectures is essential. Grid software must adapt to growing energy demand, new regulatory requirements, and the integration of more decentralized energy sources. Solutions should be modularly designed to enable easy and fast replacement of components with new and improved versions. Also, using scalable technology like containerization and orchestration tools like Kubernetes allows applications so scale dynamically depending on actual. These solutions can ensure performance as well as save cost since you only pay for what you use. One example is heavy analytics or training of AI algorithms that can introduce temporary load peaks.
4. Regular Updates and Patches: Vendors should provide regular software updates to address bugs, vulnerabilities, and performance improvements. By supporting Continuous Integration/Continuous Deployment (CI/CD) methodologies software updates can be made considerably faster. This requires access to the software by the supplier through deployment pipelines over the internet.

Recommended Technical Assurance Process

A structured Technical Assurance Process ensures that grid optimization software is reliable, secure, and fit for purpose. This process generally includes multiple steps over a longer period of time from initial idea to operational deployment.

When selecting suitable suppliers, independent audits results like penetration testing for software security or interoperability certifications can be requested to assess the software's security and functionality prior to deployment.

To validate and test the software against predefined technical requirements, it is advised to run a smaller pilot deployment using a subset of the grid data, for example one or a few substations, to ensure its effectiveness in a real-world scenario without affecting the entire grid.

During system deployment a gate-based system to validate the solution is common with functional and performance tests first carried out in a local test system, disconnected from the real grid process. Then user acceptance testing based on realistic use cases are performed. Finally, a go-live which includes taking the system into live operation and validating that the transitioning from the test to the live environment is executed correctly.

Post-deployment monitoring of the solution is also crucial to ensure the system functions optimally under live grid conditions and to catch any malfunctioning or underperformance.

System and Equipment Modelling

As already described for the concept of Digital Twins, software for grid optimization often involves comprehensive modelling of the grid topology, assets, customers as well as connected technologies including Distributed Energy Resources.
The physical power system model forms the basis for grid analytics, operations, forecasting, risk assessment, planning. Compared to traditional grid software, characteristics of novel system modelling tools could include

- Capabilities to simulate advanced future and what-if scenarios based on historical data allowing for realistic testing and validation.
- Incorporate real-time weather data, generation and load forecasts.
- Utilize AI algorithms to process big data, bridge data quality issues and model complex dependencies.
- Include behind-the-meter assets, historically not visible to the grid operators.
- Use probabilistic methods to model the future.

The models are still most often tightly integrated with the operations in the control room or the planning and maintenance systems. With increasing amounts of data to process and the need for real time control, some modelling and analytics functionality are considered for deployment at the grid edge, in for example substation edge computers, IoT devices or smart meters.

Procurement

Procuring innovative software solutions presents several challenges. Identifying the right solution is complex due to limited performance data and vendor track records, while ensuring compliance and security can be difficult with newer technologies. Procuring grid optimization software requires also grid operators to carefully evaluate their unique grid needs and constraints and mapping these to existing off-the-shelf software solutions can be hard. Also, each grid operator has its unique set of legacy systems, which affect both functional gaps as well as system integration aspects. Finally, traditional procurement processes can slow the adoption of fast-evolving technologies, making streamlined, agile approaches essential.

One available procurement type is the “Negotiated procedure” which allows for an open dialogue and negotiation between the purchaser and a few suppliers to reach a final design which is allowed to be evolved throughout the process.

Any customization of software that cannot be achieved through low intrusive means such as APIs or configurations should be avoided. Including a level of co-development of standard functionality in the final contract might however also be necessary. This requires a close collaboration between the parties and a prioritization of the supplier roadmap to include new functionality over time that can benefit both parties including other customers of the supplier.

Due to the fast-paced changes grid operators are seeing both in terms of technical and regulatory evolution as well as customer behaviour, a grid optimization solution cannot be static once deployed. It must evolve along with the changing needs. Software as a Service (SaaS) contracts enable this evolution since they commonly include frequent upgrades to provide software maintenance, security updates as well as functional enhancements. Given the critical nature of grid software, a SaaS contract should account for long-term use, including warranties, maintenance agreements, and service-level agreements (SLAs).

Tendering Specification Recommendations

When creating tender documents for grid optimization software, key specification recommendations include:

1. Functional requirements
   Define the key features required now but also what is expected for the future. Expect that some of the functional needs will have to be developed as part of the delivery. Also, keep in mind that future functionality is a moving target which should not be set in stone. Supplier roadmaps often give good insights into the direction in which the technology will evolve.

2. Interoperability and system integration
   Describe existing systems and processes to outline the expected goal with the integrated system. Specify as clearly as possible the data exchange between existing systems and the new software to be integrated. Use established communication protocols and describe existing APIs. This will make data flows easier to establish, shorten the deployment time and reduce the risk.

3. Performance and scalability
   When definition performance requirements it is important to at the same time provide the boundary conditions affecting performance including for example type of data to be

ingested into the system, frequency volume of data ingestion, number of simultaneous users expected and future scalability needs. High availability/uptime requirements, complexity and richness of the user interface, system integration and workflows and security requirements can also affect execution and may increase infrastructure needs to reach a satisfactory level of performance. Addressing these requirements typically requires balancing performance with system complexity, cost, and resilience, as each added layer of functionality or compliance can affect overall system performance.

4. IT infrastructure
   Cloud-based software offers numerous advantages over on-premise solutions, particularly in terms of flexibility, cost-efficiency, and scalability. Public cloud solutions are well suited for also sensitive data and mission critical system. However, if local security legislation or policy restricts the use of public cloud, private cloud solutions operated by the DSO is a good alternative providing similar benefits. Compared to local hardware deployments, cloud provides Scalability and flexibility, Cost efficiency, Automatic software updates and maintenance, Improved security and availability and Reduced IT administration.

5. Cyber security
   Require compliance with cyber security standards such as ISO27001, NIST Cyber Security framework, OWASP and similar for all mission critical software systems.

6. Delivery model
   Consider a phased deployment with and MVP to establish the most critical system foundations followed by one or several phases where additional value adding functionality is taken into operation.

Typical Lead-Time for Deployment

The lead-time for deploying grid optimization software can vary based on the size and complexity of the system, ranging from a few months to several years, and no general recommendation can be given.

The activities that are most often on the critical line and have the largest impact on total lead time are usually related to data quality, system integration and software development.

Data quality - Data required for most grid optimisation systems include the network model with connectivity and asset information, customer information and different type of measurement data. Keeping this data up-to-date and with high quality will reduce lead times.

System integration - System integration usually involves third party suppliers to contribute to the successful system interoperability. By using standardized interfaces and protocols risk and lead times can be reduced.

Software development - Co-development of new functionality may be required to achieve the purpose of the system. Agile methods with frequent delivery of functionality in smaller batches can enable fast deployment of critical system functions while allowing for continuous delivery of functionality enhancing the value delivered by the system.

In general, the duration and risk of a system installation can be managed by reducing complexity and trying to solve general issues at an early stage of the deployment. Complexity can either be reduced by defining and implementing an MVP with a limited functional scope or by deploying the system in a subset of the grid infrastructure.

Recommended CBA Methodology

If we succeed in optimizing the traditional electricity distribution grid into actively managed, flexible grids, the impacts will be significant in multiple areas. The benefits depend heavily on local regulation though and should be separated into OPEX and CAPEX to highlight the often more complex regulatory environment to quantify the value of CAPEX savings.
Expected OPEX savings:

- Increased remote diagnostics, predicting faults, detecting issues earlier and reducing field works.
- Reduced losses, technical, administrative as well as fraud.
- Reduced outage costs, increasing grid reliability KPIs and reducing field works.
- Increased regulatory compliance, avoiding potential penalties for non-compliance of e.g. voltage quality.
- Effort and time for new grid connections could be reduced by automating large parts of the processes.
- Recurring issues with over and under-voltages as well as overloads could be detected faster and analyzed remotely, in turn reducing both OPEX costs for dispatching field crews to deploy power quality meters, identify the source of error.

Expected CAPEX savings

- Deferred and avoided upgrades, since increased utilization of existing infrastructure could improve by up to 35-40%, reducing the need for new infrastructure per distributed kWh.
- More efficient grid expansion planning prioritizing investments with high impact based on in-depth grid insights and improved load forecasting.
- Avoided over-dimensioning of grid assets.

- Maximizing existing asset lifespan by reducing asset overload, minimizing stress and thus delaying replacement needs.

While CAPEX savings vary depending on the grid's baseline condition, size, and the scope of digitalization, studies have shown that innovative grid software can deliver savings ranging from 10-30% of planned CAPEX over a decade. If this transformation is regulated appropriately, it could ensure a fair distribution of these savings among distribution system operators, flexibility consumers, and flexibility providers [28][29][30].

Example Cases

Nordic Smart Grid project (Norway)

The Nordic Smart Grid project (2015–2020) in Norway, funded by the Norwegian government and EU programs, focused on implementing smart grid technologies such as demand-side response, smart meters, and energy storage systems. The goal was to enhance grid flexibility and efficiency, enabling better integration of renewable energy. The project demonstrated how advanced technologies can optimize grid operations and support a low-carbon energy transition.

CoordiNet (Europe)

The CoordiNet project (2019-2022), funded by Horizon 2020, enhances grid coordination by integrating distributed energy resources (DERs) and optimizing grid operations. It uses flexibility platforms for DERs to provide grid services and promotes real-time coordination between Transmission and Distribution System Operators (TSOs and DSOs). The project also facilitates market integration of small-scale energy producers.

Project EDGE (Victoria, Australia)

A partnership between the Australian Energy Market Operator (AEMO), AusNet Services, and Mondo, this project pilots a Distributed Energy Resource (DER) marketplace. It models advanced coordination of DERs to enhance grid flexibility and reduce congestion.

LV orchestration of EV charging (Auckland, New Zealand)

Counties Energy (Counties), a distribution network operator in Auckland, New Zealand, together with Plexigrid and EV charging platform operator, OpenLoop, joined forces to co-develop a solution to demonstrate active orchestration of DER on the electricity network to alleviate load during times of peak demand. The project, partly funded by AraAke, which is still underway, ultimately aims to demonstrate an end-to-end proof of concept for active capacity management.

Application of mixed Innovative Grid Technology solutions

This paper includes a number of individual innovative grid solutions, their attributes and applications. However, most technologies are capable of working collectively to present a far greater impact than each would independently.

This chapter works from a real life worked example, to provide guidance on how to assess this potential.

The challenge

The current grid in an area cannot connect to deliver the renewable energy pipeline of projects (totalling 650MW) to meet wide-scale electrification net zero demands. It needs a rapid major upgrade to meet consumer expectations and developer timelines. Grid enhancing technologies such as Modular Power Flow Control (MPFC) technology and Dynamic Line Rating (DLR) are selected as both viable technologies to provide this increased capacity in the timescales required.

A study was conducted by local power system experts to analyze the combined capabilities of Modular Power Flow Control technology and Dynamic Line Rating to increase grid capacity on an area of the 110 kV and 220 kV grid under a set of 2024 scenarios.

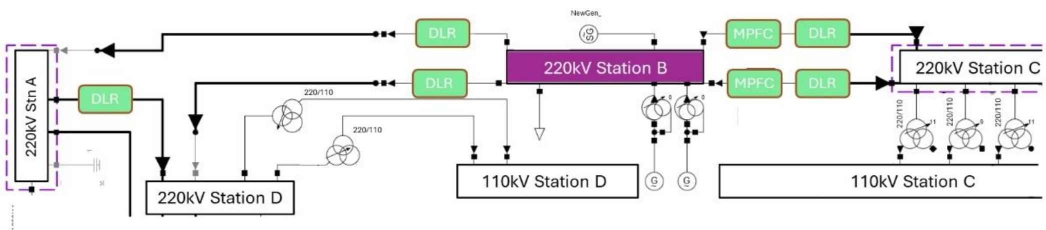

Figure 20: Real-life network showing candidate locations for Modular Power Flow Control (MPFC) and Dynamic Line Rating (DLR)

The study

Figure 20 shows a section of the network modelled with the pipeline of generation seeking connection at 220kV substation B (purple). If no innovative grid technologies were implemented by 2024, the available capacity on surrounding circuits would be 350 MW. This is significantly less than the nominal system capacity due to congestion on three 220 kV circuits, limiting the output of existing and new generation in the area.

In a scenario where only DLR was applied, only two deployments of the five considered in Figure 20, provided net benefit. This permitted a 100 MW increase in capacity for renewables. However, there is latent network capacity on other circuits which the power does not naturally flow.

In another scenario, Modular Power Flow Control was added in the two candidate locations shown in figure 16, which resulted in an additional 150 MW of available capacity on the system. However, in this scenario the static line ratings of the grid operator are only used.

In a further scenario, a combination of Modular Power Flow Control and Dynamic Line Rating was added to evaluate what would be the synergies of using both technologies together. The Modular Power Flow Control was now able to access the higher ratings of the Dynamic Line Rating, but also the redirection of the power flows by the Modular Power Flow Control made it possible to derive benefit from additional Dynamic Line Rating on another three circuits. In total over 300 MW of capacity was unlocked (total of 650 MW). The results for each scenario are summarized in table 12 below.

Scenario	Total number of Modular Power Flow Control deployments	Total number of lines with DLR	Increase in power generation [MW]	Total new generation [MW]
Base Case (existing network)	-	-	-	350
Dynamic Line Rating	-	2	+100	450
Digital PFC	2	-	+150	500
Digital PFC and Dynamic Line Rating	2	5	+300	650

Table 12: Example Case of the benefits of combining Modular Power Flow Control and Dynamic Line Rating

This example uses the Modular Power Flow Control and Dynamic Line Rating, but exactly the same process could be used to examine other two or more combinations of technologies that impact on the capacity of the system in this report, e.g. advanced conductors or superconductors.

When considering the other technologies in this report the same previously described study can be extended. Digital twin technologies or monitoring sensors as described above, both improve the accuracy of information being received by the control room operator and automated protection or controls. This will manifest itself in the margins for error that we allowed for in the way a network study is conducted, with an uncertainty factor being added into the study. There are a variety of ways this is done but all add a conservative margin to what the network would be expected to manage e.g. higher loads of generation to ensure some headroom for the unknown. Reducing these to reflect the use of better monitoring sensors or accuracy of data from a digital twin enable these technologies to be accumulatively added to the grid.

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into the study. There are a variety of ways this is done but all add a conservative margin to what the network would be expected to manage e.g. higher loads of generation to ensure some headroom for the unknown. Reducing these margins to reflect the use of better monitoring sensors or accuracy of data from a digital twin enable these technologies to be accumulatively added to other innovative grid technologies.

When considering the synergies and benefits of network topology optimization tools/software with other technologies the same network modelling can be augmented with the use of network topology optimization software directly into the network modelling software where an interface is available. Alternatively, user written codes e.g. python can be used to implement the suggested actions for optimization into each network model snapshot or case being considered. Care needs to be taken with the sequence of actions to ensure that automated controls operate correctly. For example, both Modular Power Flow Control and recommended optimization actions in the control room energy management system could be automated and in this case the timing of these should reflect real-life.

Concluding recommendations

This paper has made and supported a number of key recommendations for the deployment of grid optimizing technologies in the distribution network. Whilst effort have been made to make these recommendations self-explanatory and standalone, their application would benefit from close co-operation with representatives of the relevant members of the CurrENT association.

Recommendations for NRAs

Innovation Incentives

CurrENT has recognized and been actively supporting the need for incentives to support DSOs and their introduction of grid optimizing innovative technologies.

It has and continues to recommend that regulatory bodies and policy makers both nationally and European, put incentives in place to support the introduction of these technologies. As mentioned in many places in this paper the introduction of new technology can be highly effective for DSOs, but initially requires time and resources to be diverted to the task. This places financial costs and short-term resource management impacts on DSOs that need to be acknowledged and supported by industry.

Incentives from policy makers, regulators, EC and other sources also has a second almost equally important role in combating perceived risk from new technologies. DSOs are often questioned on their need to use, or perceived risk in applying a new technology. Incentives show that wider industry stakeholders recognize the importance of the technologies and there is universal agreement on the risks of failure to use technology to address network needs more efficiently outweighs any perceived risks from the technology itself.

CurrENT supports the introduction of Benefit Sharing based renumeration approaches to incentives to encourage the deployment of innovative grid technologies. This ACER backed initiative, has had recent EC and industry support at the recent Copenhagen Infrastructure Forum 2024, with a conclusion to National Regulatory Authorities to:

'The Forum invites NRAs to consider the adoption of innovative regulatory approaches, such as benefit sharing, contributing to the uptake of network efficiency technologies. This work should also explore opportunities for recognition by NRAs of costs for early stakeholder engagement, including local benefits, into the tariffs. ACER and NRAs should report on the outcomes of the work with NRAs in the next Forum.'

CurrENT endorses and supports this conclusion. In practical terms, Regulators will need to define a system need as well providing a projected solution using traditional technologies and infrastructure as the baseline for cost projections. DSOs would then provide tenders to solve the system need using innovative grid technologies, where the innovative solution is likely to be far less CAPEX intensive. The level of renumeration would then be based on a percentage of the difference between the initial projected cost with conventional technologies and the proposed innovative solution. This would help overcome the existing CAPEX bias when it comes to renumeration of infrastructure projects, highlight the importance of innovative technologies, and tackle the issue of 'perceived' risk relating the deployment of innovative grid technologies.

Anticipatory Investments

Various studies have shown the benefits of 'no-regrets' anticipatory investments in grids. Investments to increase the grids capacity should not be focused on the projected needs now, but rather in anticipation of increased demand through rising levels of electrification, digitalisation, and penetration of renewable energy into the grid.

CurrENT supports the concept of Anticipatory Investments and also that Anticipatory Investments apply to any and all investments that would address projected needs. This means that Anticipatory Investments should start with fast build network efficiency projects that can be delivered in the next 1-3 years to address short term projected needs, and for which Innovative Grid Technologies on the distribution network are ideal.

By 'oversizing strategically' investments into grids the required investment in the future, responding to demand and generation – driven reinforcement, is reduced as additional capacity becomes available. For example, a large-scale expansion paired with the deployment of innovative grid technologies now allows regulators to achieve the full benefits of anticipatory investments in the future where innovative grid technologies can offer more flexibility in the grid compared to conventional expansion. Some innovative grid technologies, such as Advanced Conductors or Superconductors, serve to future-proof the network, thus catering for currently unforeseen supply or demand-side requirements.

Recommendations for grid operators

Efficiency first

This paper has sought to show the benefit of the application of grid optimising technologies to the distribution network and its operators can ensure faster, lower cost, more flexible, beneficial and seamlessly integrated solutions. Digitalization of the energy system is targeted, and essential, with universally recognized major benefits to stakeholders and network operators alike. It is advantageous not to wait, but start the evaluation through to deployment process to avail of these benefits early.

To demonstrate this, it is recommended that the reader look at the use cases presented in the paper and select from these known issues on their network to apply these technologies as alternatives.

Distribution Technopedia

CurrENT warmly welcomes the creation of a Distribution Technopedia with the EU DSO Entity to provide DSOs with a list of commercial ready technologies to minimize the effort in identifying and learning how to appraise (often new) alternative technologies. It can provide industry best practice with regard to the range of technologies for solutions that will be considered. A transparent national or European Technopedia simplifies a DSOs task of identifying technologies, sharing with stakeholders what they are and will consider, and sharing knowledge internally. It is for these reasons that it is recommended that DSOs consider a national Technopedia. Going forward, it is crucial that the DSO Technopedia includes innovative grid technologies at varying TRL. The Technopedia should highlight Innovative Grid Technologies with a high TRL that can be rapidly deployed and empower DSOs to make decisions relating to their deployment by providing clear examples of use cases and proven benefits. To encourage widespread use and effectiveness of the Technopedia it should be made easily available to DSOs in a digital format that can easily integrate new editions with updated technologies. This deployment paper can be seen as an addendum to a future national/European Technopedia which will be updated regularly. In addition to the creation of the DSO Technopedia, CurrENT advocates for the creation of alternative knowledge sharing platforms. These knowledge sharing platforms should aim to consolidate information on the benefits of new and existing technologies so that they can easily be fed into DSO needs, as well as supporting the update and renewal of the Technopedia.

Technical assurance

Technical assurance of a new technology for DSOs can be challenging due to the resource commitment it requires from technical experts that often have limited availability. However paradoxically the need for new technology is increasing to keep pace with the changing role of DSOs and the move to decarbonisation.

Therefore, it is recommended that wherever possible technical assurance should be minimized to only the areas of a new technology where the technology performance is truly essential. The suppliers of the technologies in this paper have a broad range of technical assurance experience with other system operators. They have at their disposal past investigations (or selection and proof of international standards) compliance for other customers that are equivalent or often more onerous than the local conditions. It is also recommended to work collaboratively with the supplier[s] to ensure the technical assurance process can make best use of these materials to eliminate the need for repeat works and streamline the DSO commitment.

For the same reasons it is also recommended that bespoke technical assurance work completed by a DSO is made available to peers to support their own technical assurance either bilaterally, through CurrENT or a relevant DSO association.

Application of mixed Innovative Grid Technology solutions

All of the DSO grid optimizing technologies in this paper cannot only be applied standalone, but in combination, often in a much more powerful application.

It is recommended that the technologies in this paper be considered in combination. The suppliers of these technologies can offer guidance on the possible combinations to address individual cases or needs, and there are other published examples included in the references of this paper.

It is expected that if the Technopedia concept that forms one of the earlier recommendations of this paper is developed either national or Europe wide, that this will also be another reference source of symbiotic technologies and their unique applications.

Trialing what matters

As discussed previously, the application of any new technology requires consideration on how it is to be introduced into widespread operation. Existing technological introductory processes have been built around the prolonged timelines, high resources, and very high capital expense of a project investment. The risk of a costly stranded asset is high.

This supports a slow introduction of a technology. Pilot projects followed by a period of assessment, often in less vital areas of a network are a common approach. First deployments often small then follow with another period of assessment. If successful, further projects then follow growing in size and complexity. This whole process may take a decade or more before widespread use is considered. This process is fit for purpose for a high-cost project, that uses bespoke equipment with fixed or limited capability to be reused, and whose failure or poor performance jeopardizes security of supply. The grid optimizing technologies in this paper are none of these things.

CurrENT recommends that the existing process for the introduction of new technology be reviewed and the impact that grid-optimizing technologies actually represents is considered first, and that a much more streamlined process to trial these technologies is used. All of the technologies have a method of application that provides benefits but does not jeopardize the network security, by being able to be removed from service, or failing safe, that does not impact on the continuity of the network. All of these technologies are comparatively low-cost investments, with near complete ability to be redeployed in full for a range of needs or locations across the network.

CurrENT recommends that the use of trial projects, or limited use in first deployments, be avoided in favour of first deployment[s] into full active use in the network. It expects that DSOs who perform the recommended review of the impact of these technologies will reach the same conclusion. This being that the needs and benefits of introducing the technology this way far outweigh the limited risk of stranding of any assets. In addition, that on balance that there is a negative impact on security of supply, comparing to the improvements they provide, to any risk of failure they might introduce.

Every effort has been made to make these recommendations concurrent, however innovation is perpetual, and CurrENT is committed for this paper to be a living paper and will release further updates as required.

CurrENT and its member welcome your feedback. We find have found that a collaboration approach with stakeholders and customers to be the most effective form of developing knowledge, buy in and application of new technologies.

Consequently, if you require further information, wish to pursue further investigation into one or more of the technologies in this paper we commit and would be happy to work with you.

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