Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design

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Disclaimer

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Glossary

Roles and Responsibilities

Across the world, different terminology is used to refer to similar roles and responsibilities in the coordination and control of power systems. A comparative matrix of the acronyms used for each jurisdiction is identified in Table 0-1. In this report, the local acronym is described and a generic reference introduced in this glossary is employed to facilitate comparisons.

Table 0-1: International Roles & Responsibilities Translation Matrix

Function	Australia	UK	EU	US	Japan
Own, maintain & operate physical transmission assets	TNSP	TO	TO	TO / TDO	TDSO
Transmission service and real-time balancing (i.e., balancing authority)	TSO (AEMO)	TSO	TSO	ISO/RTO/TSO (i.e., CAISO, Balancing Authority)	TSO (OCCTO)
Operate energy markets	TSO (AEMO)	Power exchange	Power exchange	ISO	Power exchange
Own, maintain and operate physical distribution assets	DNSP	DNO	DSO	DO / TDO	TDSO
Provide distribution service and coordination for DERs	DSO	DSO	DSO, third parties	DSO, DSP (NY)	TDSO
Provide retail electric energy to end users	FRMP	Retailers	Retailers	LSEs, Retailers	Retailers
Aggregate DER resources to participate in wholesale markets and offer grid services	Aggregators	Aggregators	Aggregators, VPP	DERA (CA) DCEA (NY)	Aggregator Coordinator

BALANCING AUTHORITY (BA) is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within an electrically-defined Balancing Authority Area (BAA), and supports interconnection frequency in real time. A transmission owner (TO) or ISO/RTO may be an area balancing authority also known as a transmission system operator (TSO).

DISTRIBUTED ENERGY RESOURCES (DER) as used in this report encompasses the full range of energy resources, end-use devices and communication/control systems operating on the electric system below the level of the high-voltage transmission or bulk power system. DERs may be connected to the distribution utility’s system directly or may be “behind-the-meter” on the premises of end-use customers. DERs may also be aggregated to operate as sub-resources of a virtual resource that provides services to the distribution utility or participates in the wholesale market. The key defining feature of DER is their point of interconnection below the bulk system.

DER Coordination means coordinating and optimising the operation of DER to meet various needs of the power system between bulk power system and distribution operators and DER market participation.

DER Orchestration in this document describes DER aggregator coordinated behaviour, enabling large numbers of distributed resources to act as if they are one virtual resource.

Distribution Network Operator (DNO) is a term used in several countries to describe the entity that is responsible for the distribution of electricity and that operates the local distribution network.

Distribution System Operator (DSO) refers to the entity that is responsible for planning and operational functions associated with coordinating DER services for distribution networks and/or DER participation in wholesale markets in coordination with the TSO, aggregators, and other relevant parties.

Distribution Owner (DO) is the entity that owns, maintains, and operates the distribution system that supplies electricity from the transmission-distribution interface to end-use customers. The distribution owner may also be a transmission owner (TO) and in that case is a TDO (defined below).

Independent System Operator (ISO) or **Regional Transmission Organization (RTO)** is an independent, federally regulated entity that is a Transmission System Operator (see below), a wholesale market operator, a Balancing Authority, and is responsible for transmission planning.

Load-Serving Entity (LSE) provides the electrical demand and energy requirements of its end-use customers. LSEs may be competitive retailers, regulated investor utilities, and/or governmental/community electric service providers.

Provider of Last Resort (POLR) is an entity that has the regulatory or statutory obligation to offer default electric commodity service to those consumers who do not choose a competitive supplier or for whom the competitive market does not serve.

Regulator is a general term to describe the governing entity responsible for oversight of the essential functions of the electric utility, including funding authorizations for power procurements, investments, and operational expenses. This oversight extends to rate design, planning, scope of services, and competitive market interaction.

Retailer is a competitive electricity provider who sells electricity to retail customers.

Transmission Distribution Owner (TDO) is a regulated entity that owns and operates transmission and distribution networks and may or may not be a TSO.

Transmission and Distribution System Operator (TDSO) is used in Japan to refer to the transmission and distribution network owner and operator that also is the TSO for their respective regional balancing areas.

Transmission System Operator (TSO) is responsible for real-time balancing services to the network and coordinating generation and load serving entities (LSEs) to ensure electric system reliability and security.

Vertically Integrated Utility is a utility that owns its own generating plants (or procures power to serve all customers), transmission system, and distribution lines, providing all aspects of electric service.

Key Terms

Throughout this report the following key terms have been used:

ARCHITECTURE (also referred to as "grid architecture" or "systems architecture") is the conceptual model and formal description and representation of a power system, organized in a way that supports reasoning about the structures and behaviours of the system.

ARCHITECTURE PRINCIPLES refers to several key coordination architecture principles used in this report as defined in the table below.

Principle	Description
Layered decomposition	Layered decomposition solves large-scale optimization problems by decomposing the problem multiple times into sub-problems that work in combination to solve the original problem.
Tier bypassing	Creation of information flow or instruction/dispatch/control paths that skip around a tier of the power system hierarchy, thus opening the possibility for creating operational problems. To be avoided.
Hidden coupling	Two or more controls with partial views of grid state operating separately according to individual goals and constraints. Such as simultaneous, but conflicting signals from both the DO and TO. To be avoided.
Latency cascading	Creation of potentially excessive latencies in information flows due to the cascading of systems and organizations through which the data must flow serially. To be minimized.
Observability	Function related to operational visibility of the distribution network and integrated DER. Sufficient sensing and data collection can help to assemble an adequate view of system behaviour for control and grid management purposes, thus providing desirable snapshots of grid state. The data can also be utilized to validate planning models.
Scalability	Ability of system's processes and technology design to work well for very large quantities of DER resources. Coordination architecture can enhance or detract from this desired capability.
Cyber security vulnerability	While this topic has many dimensions, the principle here is to reduce cyber vulnerability through architectural structure. Structure can expose bulk energy systems to more or less vulnerability depending on data flow structure, which depends on coordination framework. To be minimized.

DISTRIBUTION SYSTEM is the portion of the electric system that is composed of substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system.

Feed-in-Tariff (FIT) is a regulated tariff through which a customer is paid on the total output of the certain types of distributed energy resources (e.g., customer solar photovoltaic systems) and, in some cases, on the excess energy (net of customer load) exported into the network. In the U.S., a type of FIT is referred to as net energy metering.

Locational Marginal Price (LMP) is the price for electric energy at the physical point (or "node") at which the transmission system and distribution system interconnect. The price reflects: 1) the constraint mitigation for the related area transmission system, and 2) losses on the transmission system to that node.

Markets as referred to generically in this report include any of three types of markets: wholesale, distribution, and retail customer energy services. Distribution markets in this document refer to the competitive provision of services to operate the distribution network. While there has been discussion of distribution level energy markets distinct from wholesale markets, these have not yet developed and therefore this report does not address these potential markets.

Multiple-Use Applications (MUA) is a framework and set of rules to enable storage resources to participate in stacking of services provided to different entities (TSO, DO, end-use customer) and their associated revenue streams.

Net Load is the load measured at a point on the electric system resulting from gross energy consumption and production (i.e., energy generation and storage discharge). Net load is often measured at a T-D Interface and at customer connections.

Non-Wires Alternatives (NWA) is the use of DER services as potential alternatives to distribution network infrastructure "wires" investments and/or provide operational services such as voltage/reactive power management.

Restructuring is the process of replacing a monopoly system of electric utilities with competing sellers, allowing individual retail customers to choose their electricity supplier but still receive delivery over the power lines of the local utility. It includes the reconfiguration of the vertically-integrated electric utility.

1 Executive Summary

1.1 Purpose

The Newport Consortium[1] (Newport) was contracted by the Australian Energy Market Operator Ltd (AEMO) for an international review of system architectures for orchestration of Distributed Energy Resources (DER). AEMO requested that a report be provided, that summarises the international experiences and provide analysis to assist AEMO in exploring future system architectures for the orchestration of DER.

Australia has world-leading penetrations of energy sourced from rooftop solar and is forecasting a rapid uptake of distributed battery storage systems across the National Electricity Market (NEM). With an increase in Distributed Energy Resources (DER) there is a growing opportunity to effectively coordinate and optimise these technologiesto deliver a more productive and efficient power system to consumers. Coordinating and optimising DER effectively will enable consumers to both have the power to actively manage their electricity consumption and generation as well as provide opportunities to participate in existing and emerging markets.

Effective integration of large scale DER into the electric network as well as utilization of DER services for wholesale markets and distribution network services will require operational and market coordination between AEMO and distribution network operators. This involves developing effective system architecture, including market designs, and operational structures (including controls) to execute DER coordination reliably, otherwise customer value may be negatively impacted. This analysis raises the need for early identification and action of long-lead time matters and the potential need for interim measures to be implemented by AEMO under the current regulatory regime. To this end, this report developed by the Newport Consortium of leading experts on DER coordination architectures summarises international experiences to-date and employs comparative analysis to assist AEMO in exploring options for future system architectures for the coordination of DER.

1.2 Methodology

In consultation with AEMO, the following six primary locations were identified as relevant for AEMO and a detailed analysis has been undertaken throughout this report. These locations currently have ongoing discussions regarding architectural frameworks involving roles and responsibilities and control coordination for real-time coordination of DER relevant to Australia, these have been listed in order of relevance and insights:

- United Kingdom
- European Union
- California
- New York

[1] The Newport Consortium is led by Newport Consulting with Energeia, Strategen, Hawaiian Electric, Dr. Kristov and Dr. Taft of the Pacific Northwest National Laboratory.

- Japan
- PJM Market Area

Additionally, New Zealand, Hawaii, and Texas were reviewed for specific relevant architectural or comparative insights.

The approach to this review involved two parts: 1) conducting primary and secondary research through interviews with key personnel and gathering relevant documents in selected international locations, and 2) assessing the findings against a reference DER coordination architectural framework.

The Newport Consortium conducted a total of over 20 in-person and teleconference interviews via a common set of questions with TSOs and DOs as well as other stakeholders in each location. The interviews and document research informed the architectural analyses in this report.

A key aspect of the international discussions of DER operational coordination involves potential expanded roles and responsibilities for the distribution network operator — the concept of Distribution System Operator (DSO). The DSO concept has evolved out of two concerns: 1) the problem of managing high levels of variable DER interconnection and utilization for both bulk system and distribution operations; and 2) the emerging impacts on distribution network operations from the uncoordinated bulk power system use of DER. In locations using DER for distribution network services, it is possible that uncoordinated use of DER can also impact area transmission system operations. These issues have led to the development of new models for operational and market coordination between transmission system operators and distribution operators. This is referred to in this report as “DER coordination” or “TSO-DSO coordination.”

For context, the DER coordination discussions globally involve a spectrum of possible conceptual models in terms of the complementary roles of DSO and TSO at the Transmission-Distribution interface[2] as illustrated in Figure ES - 1 below. These conceptual coordination models are used in this international review as a simplified means to provide evolutionary and comparative context.

[2] P. De Martini and L. Kristov (2015), *Distribution Systems in a High Distributed Energy Resource Future*, LBNL, available online: https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf

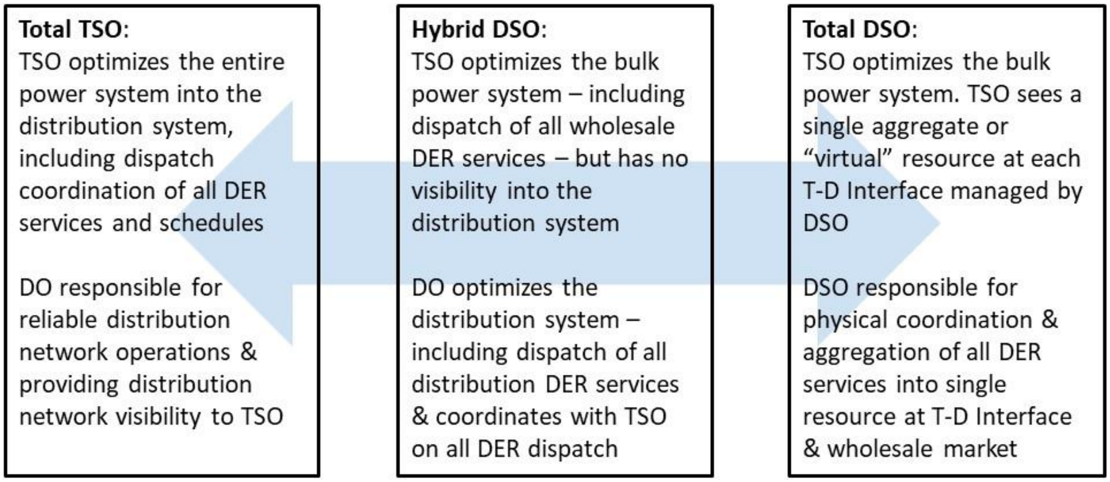

Figure ES - 1 Spectrum of Conceptual Models of DER Coordination

Note that it is very unlikely that either a full conceptual Total TSO or Total DSO will be employed in any location, rather future architectures will likely be a variation of the Hybrid[3] model oriented to be either more TSO-centric or DSO-centric in terms of primary DER coordination responsibility. Beyond these contextual models, a conceptual coordination diagram was developed for each of the primary six locations illustrating the current architecture as well as diagrams that identified future architectures under consideration. An assessment of these coordination architectures is provided in Chapter 3 for five international locations with active DER coordination architecture development efforts. [4] This assessment includes summary level identification of potential issues and considerations, including potential bottlenecks, distribution operational bypasses, scalability, information flow paths, roles and responsibilities, and other issues that become apparent from examination of the architecture.

[3] De Martini and Kristov refer to the Hybrid DSO model as "Minimal DSO" in their 2015 LBNL report

[4] PJM was not included as it does not have any active discussion underway regarding DER coordination and therefore no potential future architecture proposed or that can be implied for analysis at this time.

1.3 International Assessment

The international review of DER coordination architectures has found that future DER coordination architectures are at an early stage of development with international locations at the forefront. Also, outside of the UK and Japan, the current future architecture proposals do not represent multi-stakeholder consensus on how the DER coordination architecture may develop.

Figure ES - 2 displays a continuum of DER wholesale market participation and distribution network services in relation to the maturity of the development of TSO-DSO coordination architecture and places each of the locations reviewed for this report on it. As can be seen from the diagram's upper right quadrant, none of the locations are at the stage of detailed implementation, most are in the early development stage. Every international location reviewed has many outstanding questions which have not been resolved or considered as yet, including a rigorous system architectural evaluation.

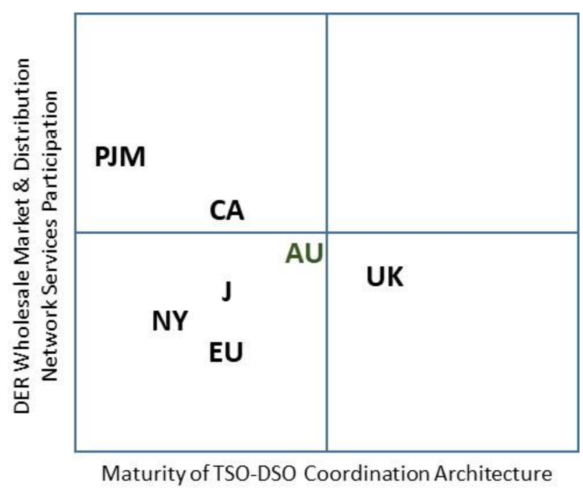

Figure ES - 2 DER Coordination Architecture Maturity and Market & Network Services Participation

In this context, the international review has identified:

- UK has the most comprehensive evaluation of various DER coordination architectures underway, including a planned benefit-cost analysis later in 2018. The UK process for developing and evaluating TSO-DSO coordination is the leading practice worldwide.
- California, New York, and PJM all have extensive DER participation in wholesale markets. California and New York TDOs are using DER aggregators for distribution network services spurring near term changes to address immediate TSO-DSO coordination with DER aggregators. Given the scale of distributed solar and battery storage in California, there are implementation insights worthy of consideration. However, there are no multi-stakeholder efforts yet to address longer-term architectural structures.
- The EU TSO and DO associations have recently developed respective white papers on proposed DER coordination architectures that are currently under discussion. However, there is limited use

of DER in wholesale markets and/or for distribution network services in the EU at this time and therefore, the papers and discussions are more forward looking.

- Japan is undergoing the final step to restructure its electric industry with the opening of retail competition, growth of solar PV and battery storage systems, and creation of a national TSO over the past few years. These changes include current early stage discussions to develop a DER coordination architecture.

However, as identified in this matrix, Australia is furthest along when considering both DER market participation experience and development of a future architecture when considering the efforts of AEMO and the ENA-CSIRO Electricity Networks Transformation program. This does not suggest there are not international insights to gain and potential collaborations that will be beneficial for Australia. For the reasons summarized above, the Newport Consortium recommends the UK Energy Network Association's Open Networks effort, the European Union efforts, and the DER market participation implementation developments in California future monitoring and knowledge sharing.

For example, the UK Open Networks analysis of potential future TSO-DSO coordination architectures has identified six models for evaluation.[5,6,7] Of these models, two approaches shown in Figure ES - 3 below highlight key architectural considerations that mirror the discussions underway in other locations. Specifically, determining the structure of the roles and responsibilities of the TSO, DSO, and DER aggregator. For this reason, the UK analysis is very helpful for any international location as the fundamental structural issues to address exist irrespective of nuances in market operations and electric network configurations.

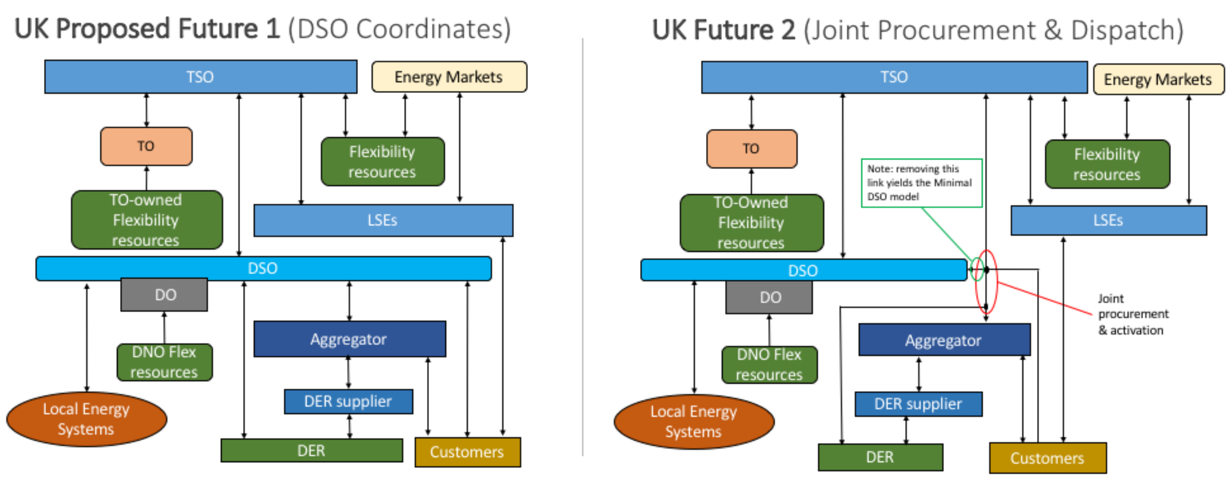

Figure ES - 3 U.K. Proposed Future Architectures

[5] Energy Networks Association (2017), *ON-WS1-P4 Commercial Paper.*

[6] Western Power Distribution, *DNO Transition DSO*

[7] Energy Networks Association (ENA) Open Networks Project (2017), *Opening Markets for Network Flexibility: 2017 Achievements and Future Direction*, available online: http://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/14574_ENA_Open%20Networks%20Report_AW_v9_Web.pdf

UK Option 1 above is close to a Total DSO model. In this option, all of the DER coordination flows through the DSO; consequently, the model makes good use of layered decomposition and has few issues with tier bypassing or hidden coupling except for the way in which DO flexibility resources are managed. These architectural principles are an important consideration and referenced throughout this report. The definitions are provided in the table below and the Glossary. A more complete discussion of these and other relevant architectural principles is provided in Appendix C.

Principal	Description
Layered decomposition	Layered decomposition solves large-scale optimization problems by decomposing the problem multiple times into sub-problems that work in combination to solve the original problem.
Tier bypassing	Creation of information flow or instruction/dispatch/control paths that skip around a tier of the power system hierarchy, thus opening the possibility for creating operational problems. To be avoided.
Hidden coupling	Two or more controls with partial views of grid state operating separately according to individual goals and constraints to be avoided. Such as simultaneous, but conflicting signals from both the DO and TO.

The arrangement for connecting DER via a DER supplier and then an aggregator to get to the DSO introduces the possibility of some cascading latency issues. Because of the layering and use of the DSO approach, scalability is good and cyber vulnerability of the bulk energy system due to DER connectivity is small.

In UK Option 2, the responsibility for DER coordination is shared by the DSO and TSO, leading to a more complicated arrangement involving these parties and the aggregators, although the sharing mechanism is not clear. This model is somewhat similar to the Total DSO model, but the sharing arrangement results in a blending of roles that will require extra coordination to perform. Option 2 partially degrades the layered decomposition structure and allows for some tier bypassing, although the proposed function-sharing ("joint procurement and activation") may prevent that from being an issue. The effect of this structure is to increase the coupling between the TSO and DSO (*not* hidden in this case), since the DSO cannot manage the DER in its service area alone while interfacing to the TSO in a modular fashion. The joint arrangement results in data flow complexity involving the DSO, the TSO, the aggregators, the customers, and DER. This is a result of the structure shown in the red oval which comes about due to the definition of joint roles instead of clean separation of functions. Cyber vulnerability is somewhat increased compared to Option 1 and scalability is difficult to evaluate, given the present lack of definition of the joint mechanisms. Note that if the short connector circled in green in UK Option 2 in Figure ES - 3 were to be deleted, this would become essentially the Hybrid DSO model. That difference illustrates a principle of grid architecture: small structural changes can have significant impacts on the resulting system's designs.

This UK example, highlights two central issues being discussed in the international locations reviewed.

The current DER coordination models for all locations exhibit considerable distribution operator bypassing, with the attendant issues of hidden coupling and bulk system cyber vulnerability.

This issue is especially prominent in NY, UK, and PJM models. All models are indicative of incremental evolution based on existing legacy structure which is not surprising. CA and UK have done a great deal in terms of modifying structure, mostly by adding elements in a reactive manner, which has led to more complexity in their structures than is evident in the others. A key issue for AEMO to consider is the extent to which DER coordination structure must be constrained by legacy industry, market-control, and even information structure, and how much freedom exists to consider structural modification in order to relieve constraints and enable new systems capabilities based on DER.

The present and future models involve two schools of thought regarding coordination structure: 1) a centralized approach where the TSO performs all coordination, and 2) layered approaches where a DSO has a significant role in coordination.

Determination of the choice of centralized or layered structure is an early architectural decision that has significant impact on the downstream decisions for architecture, design and implementation of market mechanisms, control systems, communication networks, and organizational roles and responsibilities (and consequently industry structure).

An important architectural issue is the need to coordinate and optimize significant amounts of DER for participation in both wholesale markets and distribution network services, while simultaneously respecting/mitigating transmission and distribution level constraints. This will require high levels of visibility into the operation of the distribution network, including physical switching coordination and distribution level nodal state estimation.

TSO dominant models will need to address these requirements as failing to do so may lead to:

- Distribution tier bypassing,
- Hidden coupling of operational controls,
- Inherent operational process and related technological designs that limit the ability to support large scale DER market participation, and
- Cybersecurity vulnerability from unregulated DER with unknown protection.

The DSO model resolves these issues through an architecturally simpler and more robust structure, but is more complex in practice to develop given the industry structural starting point for most power systems in developed countries.

Several future approaches under discussion internationally are based on the Hybrid DSO model and would seem to be attempts to have it both ways. However, this introduces complexity in structure and roles and responsibilities and therefore coordination processes. This is manageable at lower levels of DER market and network services participation but will face scalability issues as DER participation grows. Therefore, we anticipate that many of the international efforts will begin with an Hybrid DSO type approach and ultimately evolve toward either a TSO dominant centralized structure or a more layered DSO dominant model. This evolution will depend on if and how the hybrid structural coordination challenges involving market coordination, information flows, and controls can be satisfactorily resolved (meaning good enough as opposed to perfect).

1.4 Key Findings

The key findings from Newport Consortium's investigation for AEMO consideration include:

- There is general acknowledgement of the need for distribution-transmission coordination, rather than purely transmission level coordination, due to existing or anticipated scale of DER integration and utilization in wholesale markets and/or for distribution network services, and potential for uncoordinated operational impacts at either distribution or transmission.
- There is growing international recognition of the role of system architecture in the design considerations for DER participation in wholesale and/or distributed markets. Of particular focus is on addressing issues such as observability, tier bypassing and hidden coupling along with the potential to address these issues through layered decomposition.
- None of the leading international efforts have progressed to detailed design or implementation of DER coordination architectures including dispatch optimization.
- The specific roles and responsibilities of a DSO are still being evaluated as is the question of whether the distribution network operator/owner should be a DSO. The issues under discussion and trade-offs are discussed at length by De Martini and Kristov (2015).[8]
- In the near-term, leading overseas jurisdictions are responding to distribution level constraints via connection standards limiting exports, or market rules limiting aggregation to nodes, i.e. distribution connection points, where connection policies ensure constraints will not arise.
- Markets are considering both maximum and minimum thresholds for DER aggregation. Maximum size for a single aggregator is considered as potential mitigation to address market power and/or non-performance beyond the existing prudential requirements to participate in the wholesale market or provision of distribution network services. Also, several markets have been lowering the minimum DER participation level for wholesale markets, which is trending towards 100 kW to increase the number of DER that may participate directly (100kW or greater) or through aggregations of at least 100kW.

Based on the Newport Consortium's key findings, it has reached the following conclusions of relevance to Australia's DER coordination efforts:

- Development involve multi-year efforts to design and implement, based on benchmarks from the U.K., California, and New York, which will ideally be sponsored by policymakers and the regulator.
- DER coordination will need to involve distributor network operators as key actors in both operational information and control architectures irrespective of whether they become DSOs. From a wholesale market perspective, this could be analogous to the TSO-TO roles

[8] P. De Martini and L. Kristov (2015)

and responsibilities in several international locations. Failure to address this need will inherently lead to more issues around transmission and distribution conflicts and worse system and network security or economic outcomes.

- Aside from wholesale markets participation considerations, there is an issue of what role the DO plays regarding distribution network services.
- If any future architecture involves a DSO type role and set of responsibilities, as currently envisioned internationally, the question arises as to whether an independent DSO is needed. This is an unresolved issue under active discussion in the UK, Europe, and the United States (nationally).
- Key elements for a best practice DER coordination architecture include:
    - Developing clear objectives and identifying required capabilities for the TSO and DO.
    - Development of a DER coordination architecture, including identifying and defining the roles and responsibilities for TSO, DO, and DER aggregators
    - Wholesale – distribution network services markets coordination, and operational information and control architectures
    - DER connection, registration, and measurement requirements and communication protocols
    - Coordinated demonstrations to test and verify implementation of architectural elements described above and address industry knowledge gaps
    - Cost-effectiveness assessments to evaluate the net benefit of various options for customers, society, or other specific objectives

1.5 Report Structure

Following this executive summary, the report is organized into several sections beginning with Chapter 2: “Introduction” that summarizes the context for this report and the approach to the international review including the architectural framework. Chapter 3: “International Architectural Assessment” provides a summary assessment of the international DER coordination architectures under discussion. Chapter 4: “International System Architectures” synthesizes the locational development status and direction based on responses to the international architectural questionnaire developed for this report[9] and other related material. Chapter 5: “Conclusion” summarizes the findings from this international review and recommended considerations for Australia.

[9] Appendix B: Interview Questionnaire

2 Introduction

2.1 Project Background

Australia has world-leading levels of energy sourced from rooftop solar and is forecasting a similar rapid uptake of distributed battery storage systems across the National Electricity Market (NEM). The anticipated growth in rooftop solar and distributed storage provides a strong impetus to accelerate uptake of orchestrated distributed energy resources (DER) capabilities. A wealth of new customer energy management technologies is approaching market deployment and will assist with unlocking this potential.

However, there is a need to effectively coordinate higher levels of distributed energy resources to deliver a more productive and efficient power system to consumers. Coordinating DER means consumers have the power to actively manage their electricity consumption and generation as well as participate in existing and emerging markets both individually and collectively. This functionality increases the value available from their assets and can reduce power system costs.

Effective integration of large scale DER into the electric network as well as utilization of DER services for wholesale markets and distribution network services will require operational and market coordination between AEMO and distribution network operators. The effectiveness of this operational and market coordination should, depending on the uptake of DER, reduce the need for large-scale infrastructure development. However, this requires an effective architecture including market designs and operational structures (including controls) to execute reliably, otherwise customer value may be negatively impacted.

This analysis raises the need for early identification and action of long-lead time matters and the potential need for interim measures to be implemented by AEMO under the current regulatory regime. To this end, this report summarises international experiences and analysis to assist AEMO in exploring options for future system architectures for the coordination of DER.

2.2 Project Approach

This report is based on a comprehensive review of leading international discussions on the coordination of DER and a comparative assessment of respective emerging architectures. The approach to this review involved two parts: 1) conducting primary and secondary research through interviews with key personnel and gathering relevant documents in selected international locations, and 2) assessing the findings against a reference DER coordination architectural framework. This report also builds upon work that the consortium developed for CSIRO and the Energy Networks Association in 2017, included as part of the "Future Market Platforms and Network Optimisation Synthesis Report."[10]

[10] Energy Network Australia and CSIRO (2017). *Electricity Network Transformation Roadmap: Future Market Platforms and Network Optimisation Synthesis Report*, available online: http://www.energynetworks.com.au/sites/default/files/future_market_platforms_and_network_optimisation_0.pdf

2.2.1 Research Methodology

The initial step involved identifying a set of primary international locations to assess. These locations have ongoing discussions regarding architectural frameworks involving roles and responsibilities and control coordination for real-time coordination of DER that are relevant to Australia. In consultation with AEMO, the following six primary locations were identified in the order of relevance and insights:

- United Kingdom
- European Union
- California
- New York
- Japan
- PJM Market Area

Additionally, New Zealand, Hawaii and Texas (refer to Appendix A) were reviewed for potential relevant insights. Newport conducted a total of over 20 in-person and teleconference interviews with TSOs and DOs as well as other stakeholders in each location (refer to Appendix B). These interviews were augmented with insights from the project team members' prior experience with these jurisdictions, literature search, and documentation provided by those interviewed. The documents are referenced in each location section as well as in the bibliography.

2.2.2 Architectural Framework

<u>Analytical Methodology</u>

Throughout the analysis, architectures and architectural approaches for DER coordination were compared using an architectural framework based on a method that identifies the structural hierarchy (layers) of interaction. Use of such a framework to study DER coordination provides a common basis for examining what might at first appear to be differing grid architectures and allows the identification of the key characteristics of each.

Some advantages and capabilities inherent in this approach are:

- Structural approach to understanding coordination architecture
- Rigorous basis for flexible structure mapping for grids
- Provides a common framework for comparisons of grid architectures
- Can represent various TSO-DSO models

By basing the coordination framework on *layered decomposition*, it is possible to derive an understanding of roles and responsibilities, information flows, *observability* requirements, dispatch and control structure, and related structural issues such as *tier bypassing*. These and several other key coordination architecture principles that should be assessed in development of TSO-DSO coordination models are defined in Table 2-1 below, for further detail, refer to Appendix C. There is a considerable body of knowledge regarding grid architecture available in the references cited in this report including an application by CSIRO-ENA in the Electricity Network Transformation Roadmap initiative.[11] A detailed discussion of grid architecture is outside the scope of this report.

Table 2-1: Summary of Key Coordination Architecture Principles

Principle	Description
Layered decomposition	Layered decomposition solves large-scale optimization problems by decomposing the problem multiple times into sub-problems that work in combination to solve the original problem.
Tier bypassing	Creation of information flow or instruction/dispatch/control paths that skip around a tier of the power system hierarchy, thus opening the possibility for creating operational problems. To be avoided.
Hidden coupling	Two or more controls with partial views of grid state operating separately according to individual goals and constraints. Such as simultaneous, but conflicting signals from both the DO and TO. To be avoided.
Latency cascading	Creation of potentially excessive latencies in information flows due to the cascading of systems and organizations through which the data must flow serially. To be minimized.
Observability	Function related to operational visibility of the distribution network and integrated DER. Sufficient sensing and data collection can help to assemble an adequate view of system behaviour for control and grid management purposes, thus providing desirable snapshots of grid state. The data can also be utilized to validate planning models.
Scalability	Ability of system's processes and technology design to work well for very large quantities of DER resources. Coordination architecture can enhance or detract from this desired capability.
Cyber security vulnerability	While this topic has many dimensions, the principle here is to reduce cyber vulnerability through architectural structure. Structure can expose bulk energy systems to more or less vulnerability depending on data flow structure, which depends on coordination framework. To be minimized.

How to Apply Coordination Framework to Comparative Architecture Analysis

The architectural analyses in this report was done by examining skeletal diagrams identified in documentation gathered or conceptually developed for each assessed location. These diagrams and related documentation were assessed to identify potential issues and considerations, including potential bottlenecks, loops, bypasses, feedbacks, scalability, intended and unintended information flow paths, role/responsibility match or mismatch, and other issues that become apparent from examination of the

[11] CSIRO-ENA, *Future Market Platforms and Network Optimisation Synthesis Report, 2017 available online:* http://www.energynetworks.com.au/sites/default/files/future_market_platforms_and_network_optimisation_0.pdf

structure and/or descriptions. A discussion of the coordination architecture is provided for each location as well as a comparative discussion in Chapter 3.

Coordination skeleton diagrams are diagrams that derive from industry structure, control structure, and market functions like dispatch. Each diagram shows the relevant entities (derived from industry structure definition). Lines of operational coordination flow connect the boxes representing entity classes. Operational flows involve all the relevant information needed to coordinate the market functions and network operational functions typically in real time (T) up to T minus 45 (T-45) days for certain operational engineering and maintenance coordination activities. Flow may be unidirectional or bi-directional, depending on the nature of the coordination relationship. An example of a simple coordination skeleton diagram is shown below in Figure 1.

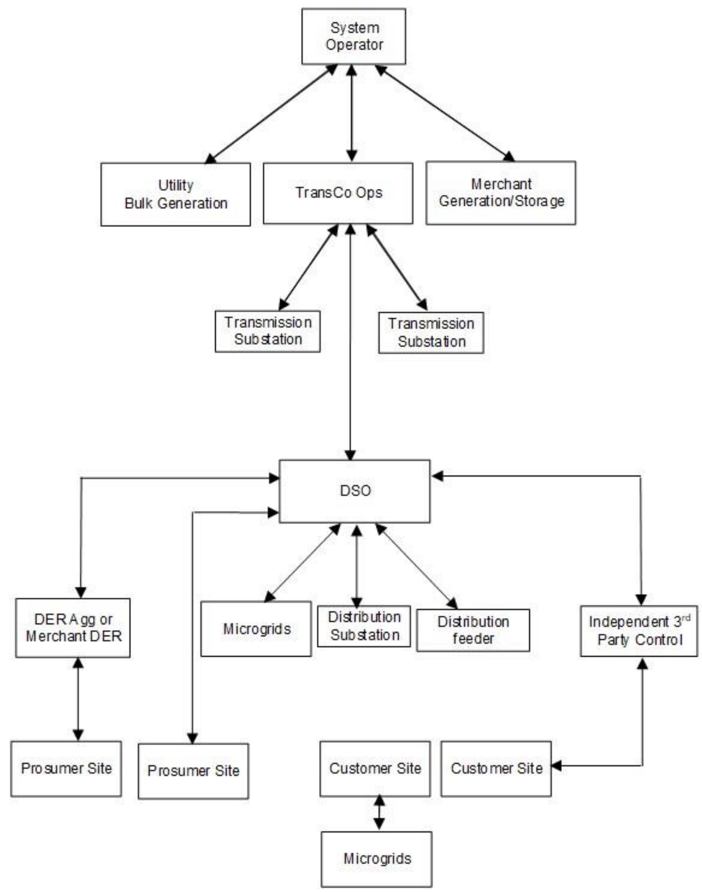

Figure 1: Example Coordination Skeleton Diagram

Reference Architectural Framework

Conceptual coordination models have been developing over the past few years and have been identified in this international review. The discussions globally involve a spectrum of possible conceptual models in terms of the complementary roles of DSO and TSO at the Transmission-Distribution interface[12] as illustrated in Figure 2 below.

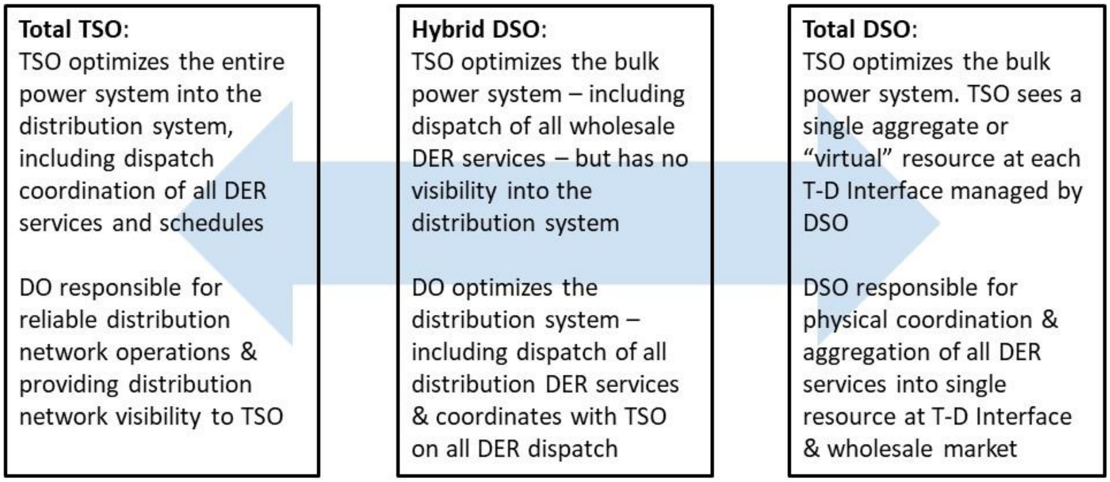

Figure 2: Spectrum of Conceptual Models of DER Coordination

The simple conceptual skeletal diagrams for each model are illustrated in Figure 3 to Figure 5 below. These are offered as a means to initially understand the fundamental relational structure of proposed coordination architecture before diving into the more complex issues as described above in the coordination framework. These conceptual models are representative of the range of potential architectures under discussion globally based on the information gathered in this international review. However, it should be noted that it is very likely that neither a full conceptual Total TSO or Total DSO will be employed in any region, rather future architectures will be a variation of the Hybrid[13] model oriented to be either more TSO-centric or DSO-centric in terms of primary DER coordination responsibility.

Total TSO Conceptual Model

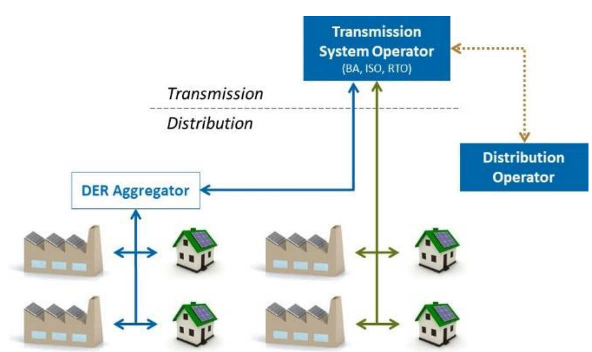

Figure 3: Total TSO

[12] P. De Martini and L. Kristov (2015)

[13] De Martini and Kristov refer to this model as "Minimal DSO" in their 2015 LBNL report

Hybrid DSO Conceptual Model

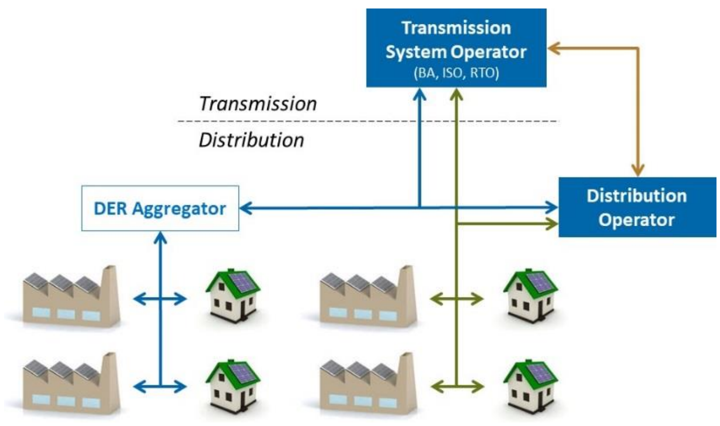

Figure 4: Hybrid DSO

Total DSO Conceptual Model

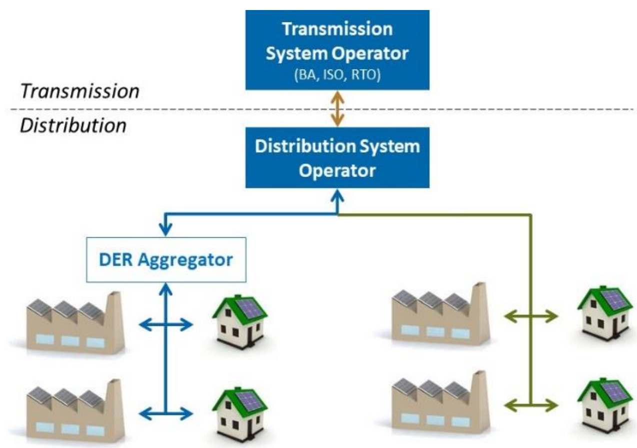

Figure 5: Total DSO

3 International Architectural Assessment

The proposed future coordination frameworks for six primary international locations are assessed in this section. This assessment evaluates each location's direction based on architectural principles are defined in the Glossary and discussed in Appendix C. For more detail on system architecture, the Pacific Norwest National Laboratory's Grid Architecture website[14] is a useful reference library as it contains a large number of reports and analysis relevant to this international review. In addition, the CSIRO-ENA report on system architectural considerations for Australia[15] is a useful reference in the application of system architecture. Note that these proposed future architectures are only at the early proposal stage and, aside from the U.K., may only represent one stakeholder's perspective on how the DER coordination architecture may develop. Additionally, none of these proposed architectures have been assessed by the respective regional entities for architectural soundness against these principles summarized in Table 2-1 above or undergone more rigorous architectural evaluation that will be required for further development.

United Kingdom

The UK Open Networks effort will deliver major findings by end of 2018. The process UK has implemented and the questions upon which it is focused are the leading practice among the locations reviewed. The UK Open Networks assessment approach is well designed and should yield results useful for consideration globally. The scope of the study involves active roles and deliverables for the TSO, DOs, and other stakeholders, with a plan for independent comparative assessment of a range of potential DSO models.

Consistent with sound grid architecture principles, UK is focusing on the key issues (cost, complexity, customer satisfaction, regulatory compliance, and network performance) to get the system structure right before specifying procedures that are more detailed, data exchanges, systems, and market mechanisms, for example. Once the preferred structure is selected and functional roles and responsibilities are allocated to TSO, DSO and other key parties, the next level of tactical and technical details can be determined with clarity of purpose.

Another key question in the UK is how to optimize DER flexibility capabilities to benefit the whole system; i.e., DER coordination. The basic driving factors of decarbonisation and consequent growth of DER and utility-scale renewables are not different to the factors affecting other countries; differences are mainly in the rates with which the various resource types are expected to grow. As such, the primary concern with reliable operation of the entire electric system is also not fundamentally different. By focusing on flexibility, the UK process adds necessary concreteness to the problem definition: the term *flexibility* captures both the needs of operators and the basis for defining specific services DER can provide and receive compensation.

[14] PNNL Grid Architecture Library, available online: https://gridarchitecture.pnnl.gov/library.aspx

[15] Energy Network Australia and CSIRO (2017). *Electricity Network Transformation Roadmap: Future Market Platforms and Network Optimisation Synthesis Report*

Specific to the system architecture under discussion in the UK, the starting point is the present architecture (Figure 6) that is close to a Total TSO model.

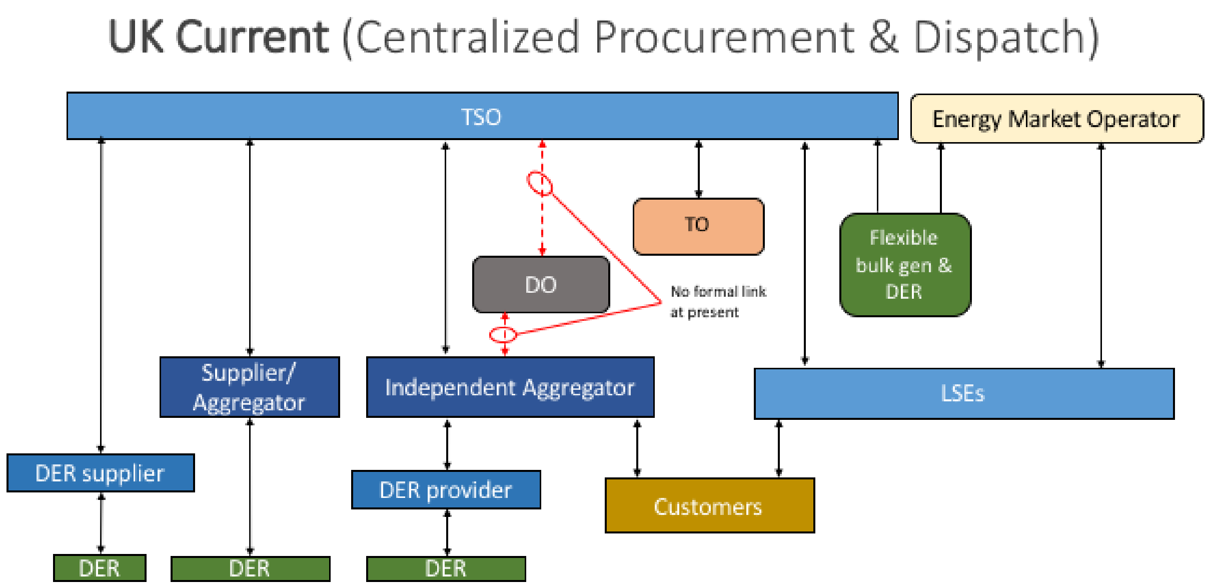

Figure 6: Current UK Coordination Structure

Recognizing the need to change, there are several future architectures for the UK under discussion,[16,17,18] with two main structural models presented here. The essential future coordination structures for these two are shown in **Error! Reference source not found.**.

[16] Energy Networks Association (2017)

[17] Western Power Distribution, *DNO Transition DSO*

[18] Energy Networks Association (ENA) Open Networks Project, *Opening Markets for Network Flexibility: 2017 Achievements and Future Direction*, available online: http://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/14574_ENA_Open%20Networks%20Report_AW_v9_Web.pdf

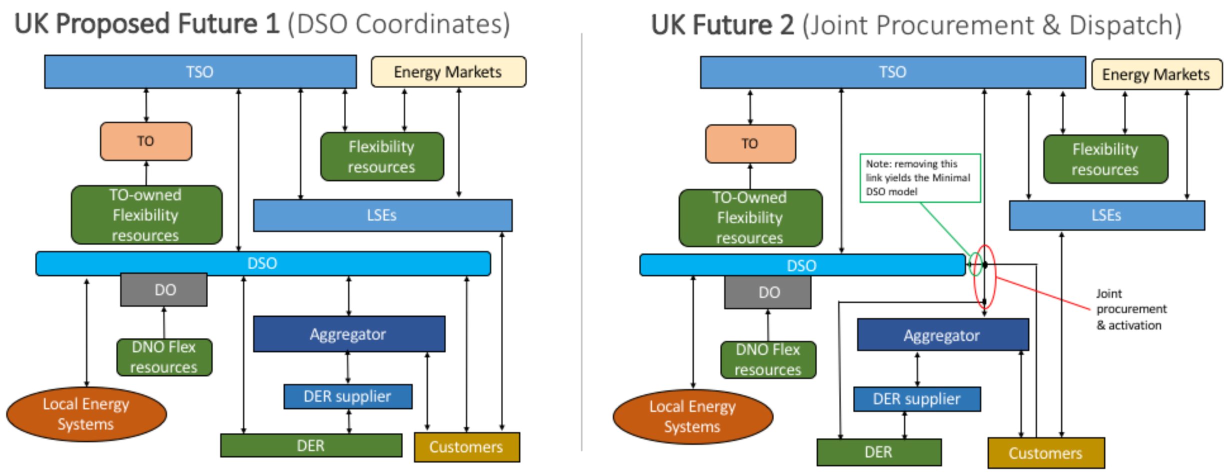

Figure 7: U.K. Proposed Future Architectures

One structure is close to a Total DSO model (Option 1 in **Error! Reference source not found.**). In this option, all of the DER coordination flows through the DSO; consequently, the model makes good use of layered decomposition and has few issues with tier bypassing or hidden coupling except for the way in which DNO flexibility resources are managed. The arrangement for connecting DER via a DER supplier and then an aggregator to get to the DSO introduces the possibility of some cascading latency issues. Because of the layering and use of the DSO approach, scalability is good and cyber vulnerability of the bulk energy system due to DER connectivity is small.

In UK Option 2, responsibility for DER coordination is shared by the DSO and TSO. This leads to a more complicated arrangement involving these parties and the aggregators, although the sharing mechanism is not clear. This model is somewhat similar to the Total DSO model, but the sharing arrangement results in a blending of roles that will require extra coordination to perform. Option 2 partially degrades the layered decomposition structure and allows from some tier bypassing, although the proposed function sharing ("joint procurement and activation") may prevent that from being an issue. The effect of this structure is to increase the coupling between the TSO and DSO (*not* hidden in this case), since the DSO cannot manage the DER in its service area alone while interfacing to the TSO in a modular fashion. The joint arrangement results in data flow complexity involving the DSO, the TSO, the aggregators, the customers, and DER. This is a result of the structure shown in the red oval, which comes about due to the definition of joint roles instead of clean separation of functions. Cyber vulnerability is somewhat increased compared to Option 1 and scalability is difficult to evaluate, given the present lack of definition of the joint mechanisms.

Note that if the short connector circled in green in UK Option 2 in **Error! Reference source not found.** were to be deleted, this would become essentially the Hybrid DSO model. That difference illustrates a principle of grid architecture: small structural changes can have significant impact on the resulting systems designs.

Europe

Today's EU system architecture is currently becoming more TSO-focused. Much of the focus on renewables integration centres on inter-regional linkages between the power exchanges at a system level to allow more effective inter-region balancing and leveraging a wider geography to manage technical renewable integration challenges. Equally, however, there is a recognition that distributed resources will play a key role in Europe's energy transition, and DOs have begun to advocate for their role as both an active system operator and neutral market facilitator. To date, power system security and stability services have been obtained by TSOs from major power plants. In the future, these provisions will need to be obtained from flexible DER, at least partially, and will be needed by DSOs. Different regions within Europe will progress at different rates but DOs are beginning to advocate for the ability to evolve into DSOs that:

- Offer flexibility and aggregated DER services up to TSOs
- Utilise DER for congestion management for their own systems
- Provide some simplistic signals up to the TSO to inform optimisation equations and when the DER can and can't participate in markets

While there is no broad consensus within the EU and much of the focus to date of the energy transition has been at the bulk system level, the model the DOs have offered provides a foundation for more sophisticated operations to be developed, informed by pilots and demonstration projects. Common-sense simplifications, such as the traffic light concept or the binary "DSO re-dispatch process" or "DSO reflag process" as previously discussed, would allow services across the TSO-DSO interface to occur for flexibility and congestion management while maintaining ownership, control and responsibility in each jurisdiction. This would represent an evolution towards a "Hybrid DSO" model, with DSOs and TSOs both playing a role in managing DER within the grid.

The essential future coordination structure proposed by the consortium of European DOs[19] is shown in Figure 8.

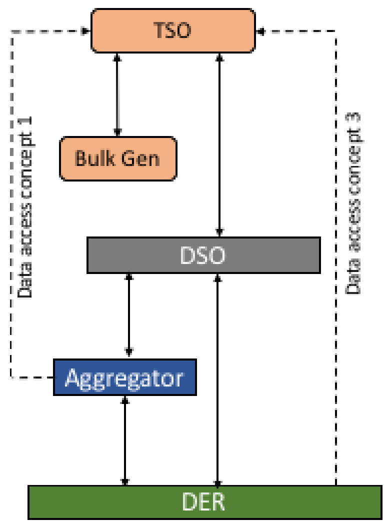

Figure 8: E.U. DNO Associations Proposed Future Architecture

Note that the present architecture in Europe is in its early stage in regards to DER coordination, and for the most part resembles the Total TSO model.

The future architecture proposals in Europe are not very well developed, so there are not too many possible observations. The structure proposed by the DNO associations is layered and the main model is very close to the Total DSO model. This arrangement results in no tier bypassing and no issue of hidden coupling, if the DSO is instructing the aggregator so that there is no bifurcation of the DER coordination. Two additional options under consideration for data flows to the TSO imply a degree of tier bypassing. These options are shown in Figure 8 as dashed lines labelled “Data access concept 1” and “Data access concept 3” (Data access concept 2 is via the DSO).[20,21] Since no instructions to DER are intended to flow back along these lines, there is no actual hidden coupling issue from a control point of view. However, there can be a race condition with the same information flowing along different paths to different destinations and potentially arriving at different times due to differing latencies. For Data access concept 3, this is not likely to be an issue, but depending on the latency in the aggregator, it could become a problem for Data access concept 1. In this case, the TSO and DSO could end up with differing views of grid state, potentially leading to conflicts in DER coordination. The problem, if it develops, could likely be resolved at the DSO, but this is something for which a solution must be specifically designed. The issue is more severe if there are many aggregators involved, since each may have a different latency.

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[19] DSO Committee on Flexible Markets (2018), *Flexibility in the Energy Transition: A Toolbox for Electricity DSOs* available online: https://www.edsoforsmartgrids.eu/wp-content/uploads/Flexibility-in-the-energy-transition-A-tool-for-electricity-DSOs-2018-HD.pdf

[20] DSO Committee on Flexible Markets (2018), *Flexibility in the Energy Transition A Toolbox for Electricity DSOs* (2018)*Ibid.*

[21] *TSO-DSO Data Management Report* (2016), available online: https://cdn.eurelectric.org/media/2061/tso-dso_dm_rep-2016-030-0382-01-e-h-E471F48A.pdf

California

California's current coordination structure is towards a Total TSO model on the spectrum resulting from incorporation of new entities and opportunities for DER to provide wholesale market and grid services that did not benefit from prior grid architectural considerations. This structure is a straightforward continuation of the ISO and distribution utility roles; the ISO optimizes the dispatch of resources to execute spot-market energy trades and balance the system in real time, while the distribution utility provides reliable power distribution services. The present architecture in California (Figure 9) is complex, with a large number of entities and complex coordination structure that has evolved in a mostly bottom-up manner. Considerable tier bypassing exists in the present system.

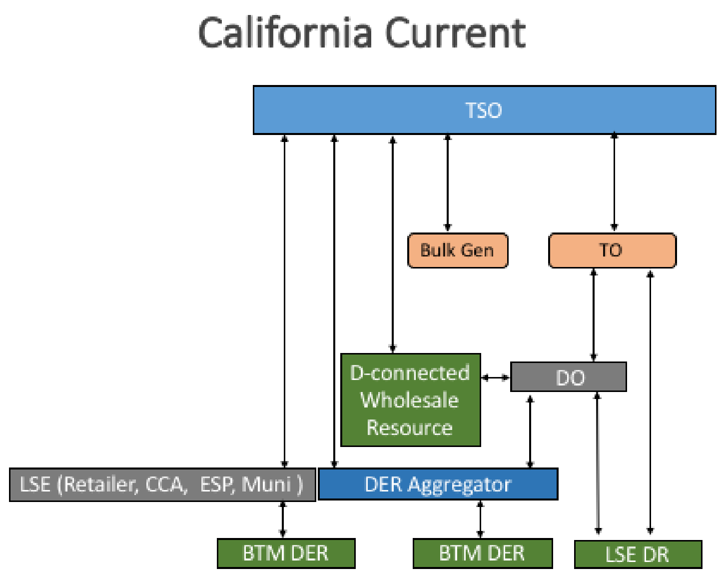

Figure 9: California Current Coordination Framework

California has not explicitly adopted a coordination model yet. The current approach is addressing immediate coordination needs informed by concurrent research. However, the future discussion towards a potential Total DSO model are unlikely to be the next step in the evolution in California. Based on early direction of these discussions the essential future coordination structure in California will likely evolve over the next decade from the current structure toward a version of the Hybrid DSO model as shown in Figure 10.

This evolution to a Hybrid DSO based model will continue to exhibit tier bypassing due to the path from DER to aggregator to TSO that bypasses the DSO. In addition, the potential for hidden coupling exists, with some aggregators, Non-IOU LSEs and the DSO all connecting to DERs. The DSO may be able to mitigate part of this but not the hidden coupling involving the TSO/aggregator tier bypass, unless some coordination mechanism is worked out between the TSO and DSO specifically for this. The presence of the direct aggregator-to-TSO connection presents a moderate cyber vulnerability to the bulk energy system. Overall scalability is good due to the near Total DSO structure, which is well layered. If the DSO is handling DER coordination for the DER in its service area, then latency cascading is possible but limited.

The need for a future coordination architecture is recognized by stakeholders given the growth and significant of DER to California's energy policies and significant customer adoption. As such, it is recognized that a future architecture is needed to meet California's longer-term needs. As described, several of the California TDOs are also developing internal perspectives. In addition, there is a formal federal regulatory (FERC) examination underway into DER coordination architectures. Based on stakeholder and FERC's interest in this issue nationally, it is likely that the California regulator will take up this question within the next two years. A benefit-cost analysis of potential grid architecture options may be developed as part of this effort.

The potential future architecture for California shown in Figure 10 is similar to the Total DSO model, except that tier bypassing can still occur due to the path from DER to aggregator to TSO that bypasses the DSO. In addition, the potential for hidden coupling exists, with some aggregators, Non-investor owned utility LSEs, and the DSO all connecting to DERs. The DSO may be able to mitigate part of this situation but not the hidden coupling involving the TSO/aggregator tier bypass, unless some coordination mechanism is worked out between the TSO and DSO specifically for this. The presence of the direct aggregator-to-TSO connection presents a moderate cyber vulnerability to the bulk energy system. Overall scalability is good due to the near Total DSO structure, which is well layered. If the DSO is handling DER coordination for the DER in its service area, then latency cascading is possible but limited.
The essential future coordination structure under discussion in California is.

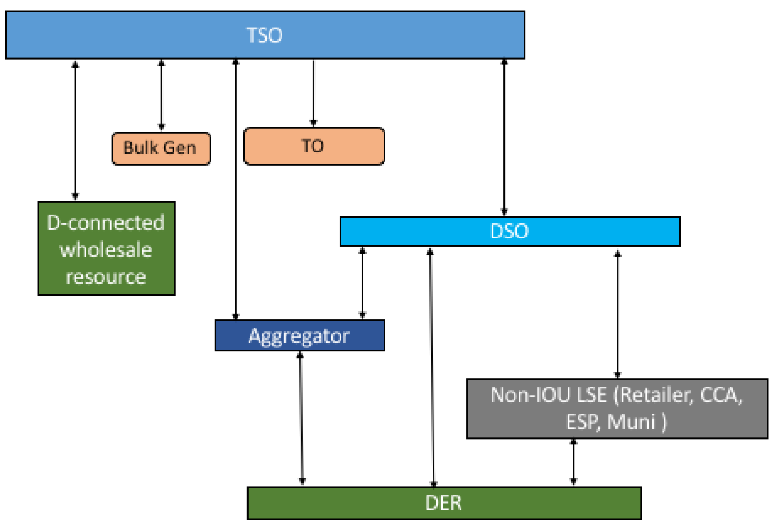

Figure 10: California Proposed Future Architecture

New York

New York's current coordination structure is the result of reconciling legacy structures built over the previous decades with the REV initiative launched in 2014. Reform efforts to improve coordination and streamline interfaces continue and are part of ongoing stakeholder processes at the NYISO, TDOs, and state regulatory agency. The starting point for these discussions is the current architecture in New York (Figure 11) that is essentially a Total TSO model.

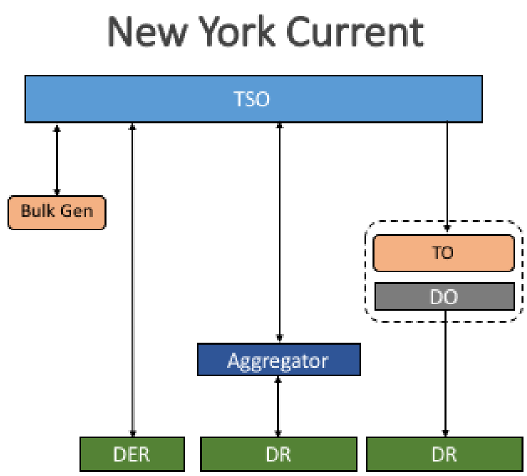

Figure 11: New York Current Coordination Framework

As such, there is no consensus in NY on the long-term coordination model. The NYISO in its DER Roadmap concept paper[22] described two simple conceptual models, as shown in Figure 12. The hybridized approach (Option 1 below) involves the aggregator interfacing directly with both the NYISO and the TDO (DSPP) including separate communications and information requirements. The NYISO and the TDOs view this current hybrid model as becoming more problematic as DER penetration and market participation increases over the coming years, as neither will have a perfect picture of what is happening with DER aggregations and individual DER and the respective and collective effects that will have on

[22] NYISO (2017), *Distributed Energy Resources Market Design Concept Proposal,* available online: http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/DER_Roadmap/DER_Roadmap/Distributed-Energy-Resources-2017-Market-Design-Concept-Proposal.pdf

markets or physical transmission and distribution security.

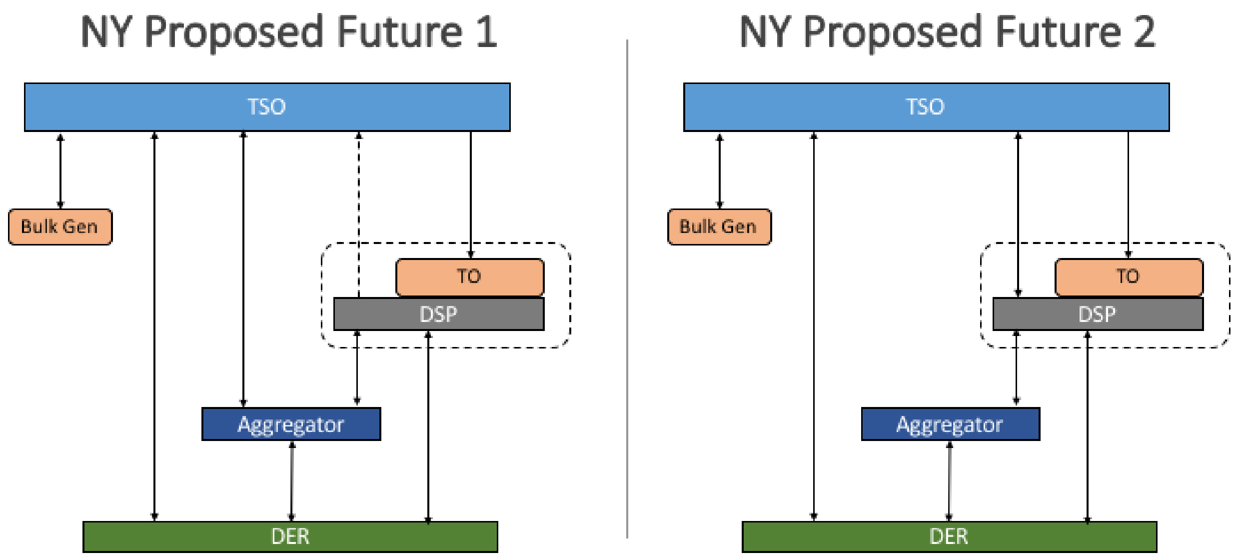

Figure 12: Options for New York's Future DER Coordination Framework

The future architecture for New York as proposed by the NYISO has two options. Option 1 is a minor evolution from the present structure. Layered decomposition is not used, and tier bypassing is extensive. Consequently, the potential for hidden coupling is also large, and scalability, both in terms of communications and computational needs at the TSO, is problematic. Cyber vulnerability for the bulk energy system is high in this model because of the connection of DER to the TSO. Cascading latency is a concern in some of the coordination paths. The potential ability of aggregators or DERs to participate at the TSO level and/or the DSP level is a source of potential issues due to hidden coupling at the distribution grid.

In Option 2, the removal of the link between the aggregator and the TSO creates some of the layered decomposition structure by eliminating one source of tier bypassing, but the presence of a link from DER to the TSO still allows for tier bypassing, hidden coupling, scalability issues, and cyber vulnerability at the TSO level. In Option 2, the DSP is potentially somewhat better able to manage the DER, and if coordination between TSO and DSP is well organized, the tier bypassing problem may be mitigated. However, if some DER are bidding into the wholesale markets and some into a DSP market, for example, then the potential for mis-coordination exists. The potential ability of aggregators to participate at the TSO level is eliminated in this model that reduces tier bypassing. However, it does not eliminate tier bypassing as some DERs can still bypass. The hidden coupling problem remains but likely at a low level.

It is clear in both options that the intent is for most DER to be orchestrated through aggregators.

Japan

The current architecture in Japan is a simple TSO model where the TSO is the balancing authority for the region with direct command and control of large and small generators. Note that the present architecture in Japan (left-hand side of Figure 13) is simple and shows a partially layered but disjointed structure. A TDSO handles DER coordination and solar PV curtailment directly. This current architecture is insufficient to deal with the complexities associated with growing volumes of controllable end devices and distributed generators in Japan.

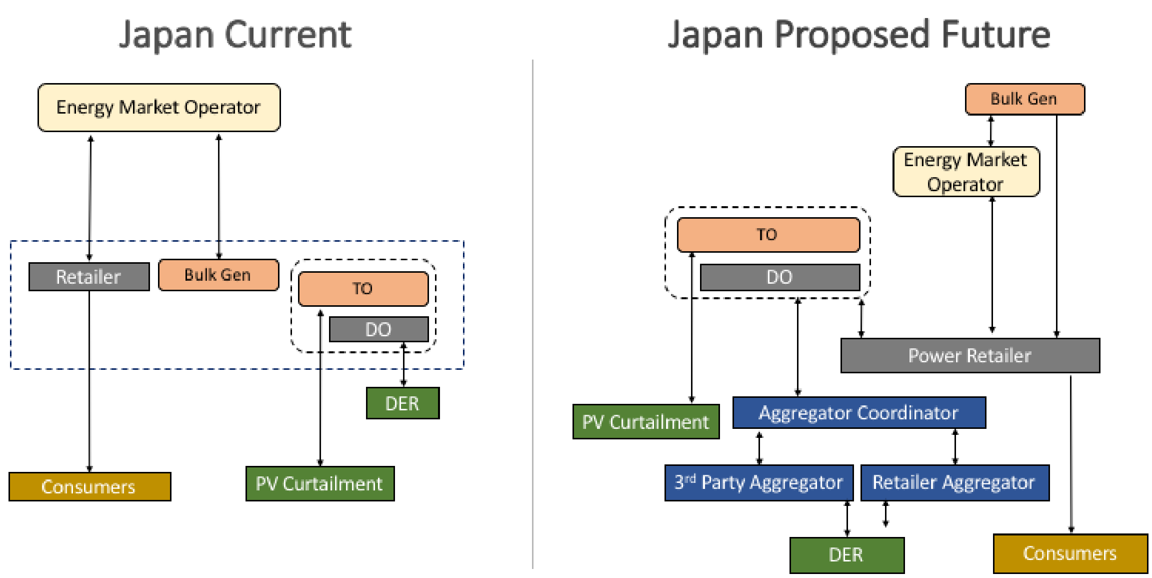

Figure 13: Japan Current and Proposed Future Architecture Direction

The future architectural direction (right side of Figure 13) in Japan is reasonably well structured from a layering standpoint, because of the fact that the TOs and DOs are not separated. There is a possibility of tier bypassing for the PV curtailment function, but this could be easily mitigated by coordination within the TDSO (combined TO/DO).

However, this future structure adds a layer through the introduction of an aggregator coordinator intended to lessen the operational burden of the TDSO. However, this allows multiple entities may be able to control or dispatch supply-side and demand-side resources creating possibilities for hidden coupling. There are hidden coupling possibilities because disjointed sets of DER on the same system may be instructed by separate organizations, namely aggregators (third party or retailer). The aggregator coordinator may be able to mitigate this issue if its responsibilities include such activity. The question here is whether separate aggregators would be able to pursue differing goals for DER aggregation or are simply acting as layered interfaces.

Additionally, the multiple layers of organizations between the DER and the TDSO, especially if the aggregator coordinator exists, means that there is a cascading latency issue that would limit fast action involving the DER. Localized control would be needed to respond to short term variations in solar output. There is a disconnect involving the energy market operator and the TDSO, but this might be resolved via the connections to the power retailer. It would be better to complete the layered structure in a more regularized way. Structural vulnerability to cyber threats is modest, since the TO is connected to solar devices. Also, this structure likely places a responsibility on the aggregators and aggregator coordinator to provide cyber security for the data flows to/from the DER, which may be an issue in terms of roles and responsibilities if these entities are not regulated. The use of aggregators and an aggregator coordinator provide some amount of communication scalability, but the centralization of DER coordination will cause computational scalability issues at the TO if DER penetration becomes high.

PJM Market

Thus far PJM has paid little attention to the role of the DO (EDC in PJM's terminology), except to recognize that some degree of information exchange will be necessary. This is understandable given the current state of DER growth; specifically, most DER that participate in the wholesale market are doing so under the DR construct, which is quite familiar to PJM participants and does not inject power into the system. Conversely, several of the 13 states in the PJM area are experiencing increasing solar PV adoption and actively pursuing policies for the use of DER for distribution network services. As such, current activity is primarily on developing new participation models for DER and DER aggregations in the wholesale market and distribution network services and deferring, for now, any consideration of TSO-DSO coordination or potential new functions the DOs may take on as DSOs. In summary, the PJM market area is at a very early stage of TSO-DSO coordination development, but initial direction points towards a Hybrid DSO model that will likely be more TSO centric given its predominant Total TSO starting point.

Summary

In summary, there are two central issues under discussion in the international locations reviewed to consider.

The current DER coordination models for all locations exhibit considerable distribution operator bypassing, with the attendant issues of hidden coupling and bulk system cyber vulnerability.

This issue is especially prominent in NY, UK, and PJM models. All models are indicative of incremental evolution based on existing legacy structure, which is not surprising. CA and UK have done a great deal in terms of modifying structure, mostly by adding elements in a reactive manner, which has led to more complexity in their structures than is evident in the others. A key issue is the extent to which DER coordination structure must be constrained by legacy industry, market-control, and even information structure, and how much freedom exists to consider structural modification in order to relieve constraints and enable new system capabilities based on DER.

The present and future models involve two schools of thought regarding coordination structure: 1) a centralized approach where the TSO performs all coordination, and 2) layered approaches where a DSO has a significant role in coordination. Determination of the choice of centralized or layered structure is an early architectural decision that has significant impact on the downstream decisions for architecture, design and implementation of market mechanisms, control systems, communication networks, and organizational roles and responsibilities (and consequently industry structure).

An important architectural issue is the need to coordinate and optimize significant amount of DER participation in both wholesale markets and providing distribution network services while simultaneously respecting/mitigating transmission and distribution level constraints. This will require high levels of visibility into the operation of the distribution network, including physical switching coordination, and distribution level nodal state estimation.

TSO dominant models will need to address these requirements as failing to do so may lead to distribution tier bypassing, scalability challenges, hidden coupling, and bulk energy system cyber vulnerability. The DSO model is architecturally simpler and more robust, but more complex in practice to develop given the industry structural starting point for most power systems in developed countries.

Several future approaches under discussion internationally are based on the Hybrid DSO model and would seem to be attempts to have it both ways. However, this introduces complexity in structure and roles and responsibilities and therefore coordination processes. This complexity is manageable at lower levels of DER market and network services participation but will face scalability issues as DER participation grows. Therefore, it is anticipated that many of the international efforts will begin with a Hybrid DSO type approach. Ultimately, these systems will evolve toward either a TSO dominant centralized structure or a more layered DSO dominant model based on whether and how the hybrid structural coordination challenges involving market coordination, information flows and controls can be satisfactorily resolved (meaning good enough as opposed to perfect).

4 International System Architectures

This section includes a summary of the current development of DER coordination architectures in the primary international locations evaluated for this study based on the multiple interviews and relevant documentation reviewed.

The international locations are organized by the maturity of the development of future TSO-DSO architecture and/or initial implementation of TSO-DO coordination of DER services that are spurring discussion of future architectural considerations.

For context, Table 4-1 summarises the estimated DER by technology-type for the primary jurisdictions.

Table 4-1: DER Installed by Jurisdiction (in MW), 2018[23]

Region	Jurisdiction	Peak Demand (GW)	Solar PV (MW)	Energy Storage (MW)	Demand Response (MW)	Energy Efficiency* (MW)
Europe	UK	60	5,514	2	6,044	-
	EU		40,000**	29	20,000	-
United States	California	65	6,569	408	2,112	1,024
	New York	34	1504	2	1,267	230
	PJM Market	150	2,617	35	9,520	-
Asia-Pacific	Japan	156	9,098	14	-	-
Australia	AEMO – NEM	35	5,920	119	511	170

** Energy efficiency is represented as peak demand reduction. **Germany alone*
Note: A blank field indicates that adequate data was not available to estimate.

Internationally, different terminology is used to refer to similar roles and responsibilities. In each location's section, we use the terminology of that jurisdiction as described in Table 4-2.

[23] Solar PV data sourced from NYISO.com; californiadgstats.ca.gov; PJM.com; gov.UK; Ogimoto, K. (2017), *Introduction: What's and why are TSO/DSO Issues?,* Institute of Industrial Science, The University of Tokyo. Energy storage data sourced from energystorageexchange.org and CPUC.CA.gov. Demand response data sourced from NYISO.com; CPUC.CA.gov; PJM.com; Bertoldi P. et al. (2016), *Demand Response Status in EU Member States*. Energy efficiency data sourced from NYISO.com; CPUC.CA.gov.

Table 4-2: Roles & Responsibilities Terms as Used in This Report

Function	Australia	UK	EU	US	Japan
Own, maintain & operate physical transmission assets	TNSP	TO	TSO	TO / TDO	TDSO
Transmission service and real-time balancing (i.e., balancing authority)	TSO (AEMO)	TSO	TSO	ISO/RTO/TSO (i.e., CAISO, Balancing Authority)	TSO (OCCTO)
Operate energy markets	TSO (AEMO)	Power exchange	Power exchange	ISO	Power exchange
Own, maintain and operate physical distribution assets	DNSP	DNO	DSO (DO[24])	DO / TDO	TDSO
Provide distribution service and coordination for DERs	DSO	DSO	DSO, third parties	DSO, DSP (NY)	TDSO
Provide retail electric energy to end users	FRMP	Retailers	Retailers	LSEs, Retailers	Retailers
Aggregate DER resources to participate in wholesale markets and offer grid services	Aggregators	Aggregators	Aggregators, VPP	DERA (CA) DCEA (NY)	Aggregator Coordinator

4.1 United Kingdom

Current System Architecture

The current power system architecture in England, Wales, and part of Scotland within the United Kingdom (UK) involves these key functional entities:

(1) the transmission system operator (TSO), National Grid, a for-profit company that owns the transmission infrastructure and performs real-time operation and system balancing for most of the UK; National Grid is currently reorganizing to comply with a regulatory directive to separate the operations function (TSO) from the transmission asset owner (TO), with infrastructure planning under the TSO, and this is expected to be completed later this year;
(2) separate power exchanges and bilateral markets for forward energy transactions, including day-ahead markets and a single market energy price, there is no greater pricing granularity;
(3) generating companies with market participating generators connected to the transmission and distribution networks;
(4) ten regulated distribution network operators (DNOs, same as DO), wires-only companies that own and operate the electric distribution systems; and

[24] EU refers to its Distribution Owners (DOs) using the acronym "DSO." To avoid confusion, this document uses DO to separate the current role of distribution owners from the proposed role in DER coordination as "DSO."

(5) numerous competitive retail energy providers, many of which own and operate generation; the six largest retail suppliers (in a field of over 50) serve just over 80% of customers.
(6) The national regulatory authority Ofgem regulates the entire electric system.

The UK system now includes a capacity market, which the government created in 2017 to address the concern that the wholesale market by itself would not sufficiently reward generation to ensure security of supply. See Figure 14.

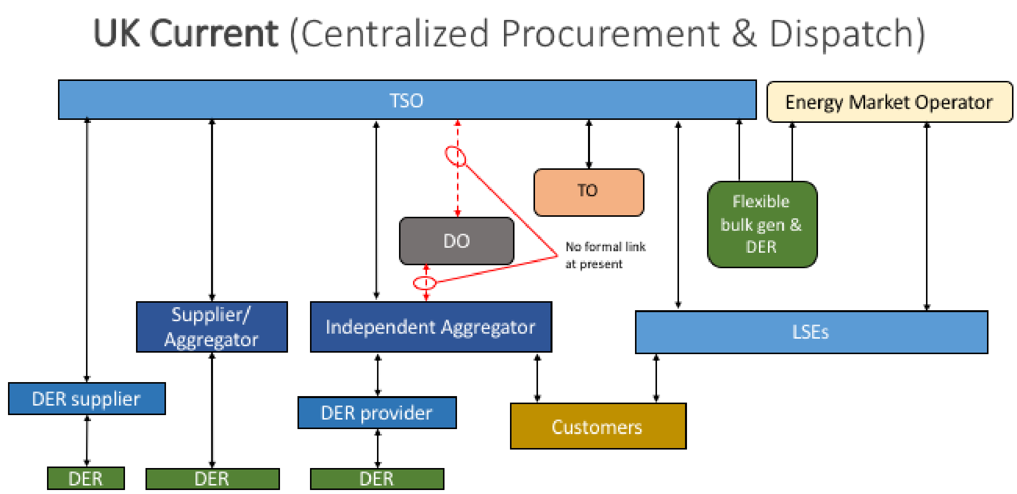

Figure 14: Coordination Framework of Current UK Model

To date, the main system operational impacts of renewable generation are thermal congestion due to wind energy production in the north, mainly Scotland, and reactive power impacts due to solar energy production in the south and southwest, particularly during low-demand summer periods.

In 2017, renewable generating facilities delivered 25% of total energy consumption; in 2016, these facilities totalled 34 GW, accounting for 34% of total installed capacity.[25] Peak demand in the system is about 60 GW and occurs in the winter. In 2016, wind and solar generation connected to distribution provided 6% of total demand. Also in 2016, distributed generation capacity was 26 GW or 27% of installed capacity. Electric storage capacity totalled 4 GW in 2016 and is expected to grow to 6 GW by 2020.

EVs are projected to reach 1 million by 2020 and as much as 9 million by 2030; UK is concerned that 9 million EVs could contribute as much as 8 GW of additional peak demand absent effective smart charging. The penetration of smart meters in UK is still low at this time. The regulator assigned the responsibility to implement smart meters to the Retailers rather than the DOs, and Retailers do not have sufficient incentives to deploy the meters.

[25] Numbers reported here are primarily from National Grid (2017), *Future Energy Scenarios*, July 2017. This document describes four future energy scenarios defined by combinations of national economic prosperity and "green ambition" in the policy realm. http://fes.nationalgrid.com/media/1253/final-fes-2017-updated-interactive-pdf-44-amended.pdf

Drivers for Change

Flexibility is a central theme in the UK's consideration of changes to electric system architecture – in particular, the need for flexible resources to support operational needs arising from more renewable generation on the system. DER are now being recognized as a source of flexibility, and both the TSO and DOs want access to it. A central architectural question is how both transmission and distribution operators can have access to the services of flexible DER, under what coordination framework. Thus, the UK agenda is to create a TSO-DSO[26] coordination framework to enable optimal use of flexible DER to support reliable operation of the electric system as a whole. The initial driver behind the need for flexibility in UK was the need to integrate renewable generation at scale. However, another key driver is autonomous customer adoption of DER. Both of these drivers are responsive to decarbonisation policy goals.

UK anticipates major proliferation of diverse DER (solar PV, electric vehicles, batteries, etc.) as a part of decarbonizing energy-using sectors of the economy, much through end-user adoption for their own purposes, referred to as "autonomous" adoption. They expect this growth will challenge T&D operations. The parties also see DER as a source of flexibility for the TSO and DOs. Using that flexibility optimally requires an architectural framework that addresses needs of both systems and their interfaces. Discussions and experiments are in progress to determine the needed framework and pathway forward (see below).

A related driver comes from the DER developers, who want to engage in multi-use applications (MUA) that stack various market and network services to maximize their value and compensation for services to the TSO, DO, and the DER customer. To this end, the DER developers are concerned about having direct access to the wholesale market without having to go through the DO/DSO as intermediary. The UK term for this concept is "alternative routes to market," i.e., the idea that a DER provider can have multiple options for where to sell services. This concern is driven by the fact that distribution level services and compensation for those services are not yet well defined. Whereas, wholesale markets are well-known and have transparent rules for access and compensation. The July 2017 Ofgem report points out that there is a "lack of established markets in local flexibility services to manage local network constraints" and points to a collaborative effort by the TSO and UK Power Networks to address this gap.[27]

Future System Architecture

One architectural element that already been decided and being implemented. Ofgem has directed separation of the transmission owner (TO) and transmission system operator (TSO) functions within National Grid, in order to assign the transmission planning function to an entity that does not have financial interest in building transmission. National Grid would be the parent company of both TO and

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[26] The major DNOs in UK have developed multi-year plans to become DSOs, with expanded functions compared to today, largely driven by DER growth. The usage 'DNO/DSO' indicates that the matter at hand applies to both the DNOs as they are today and to the DSOs they may become.

[27] Ofgem (2017), *Upgrading Our Energy System:*, *Smart Systems and Flexibility Plan*, available online: https://www.ofgem.gov.uk/system/files/docs/2017/07/upgrading_our_energy_system_-_smart_systems_and_flexibility_plan.pdf

TSO, with the latter two entities separated by a regulator-imposed operating and informational firewall. This change is slated for completion in 2018.

With regard to coordination of DER, however, given all the open issues, there is no agreed upon single vision for future grid architecture. However, there are activities aimed at this need. The leading effort is the Open Networks Project[28] initiated in January 2017 by the Energy Networks Association (ENA) with the endorsement of the national regulator Ofgem. The project includes both the TSO and DOs and is charged with examining alternative approaches to TSO-DSO coordination and providing detailed comparative assessments. The project's multi-year timeline commits to delivering, by the end of 2018, independent benefit-cost analyses of five TSO-DSO coordination models (in addition to the status quo) looking at cost, complexity, customer satisfaction, regulatory compliance, network performance, etc., with implementation to occur from 2020 to 2023.[29]

In its December 2017 report[30] describing its first-year accomplishments, the Open Networks Project reported that the participants had successfully:

- "Agreed on a definition of what we mean by Distribution System Operator and a set of core functionalities and competencies required for future network and system operation, regardless of the allocation of roles and responsibilities in any market model," and
- "Started mapping out a robust set of potential market models for DSO to understand the implications."

The report offers the following definition:

> *"A Distribution System Operator (DSO) securely operates and develops an active distribution system comprising networks, demand, generation, and other flexible distributed energy resources (DER). As a neutral facilitator of an open and accessible market it will enable competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation. A DSO enables customers to be both producers and consumers, enabling customer access to networks and markets, customer choice and great customer service."*

The report then describes eight DSO functions: system coordination, network operation, investment planning, connections and connection rights, system defence and restoration, service/market facilitation, service provision, and charging.

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[28] Energy Networks Association (ENA) Open Networks Project (2017), *Opening Markets for Network Flexibility: 2017 Achievements and Future Direction*, available online: http://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/14574_ENA_Open%20Networks%20Report_AW_v9_Web.pdf

[29] Energy Networks Association (ENA) Open Networks Project (2017), *Commercial Principals for Contracted Flexibility: Promoting Access to Markets for Distributed Energy Resources*, available online: http://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/ON-WS1-P4%20Commercial%20Paper%20(Final%20Draft)-170816-final.pdf

[30] ENA, 2017.

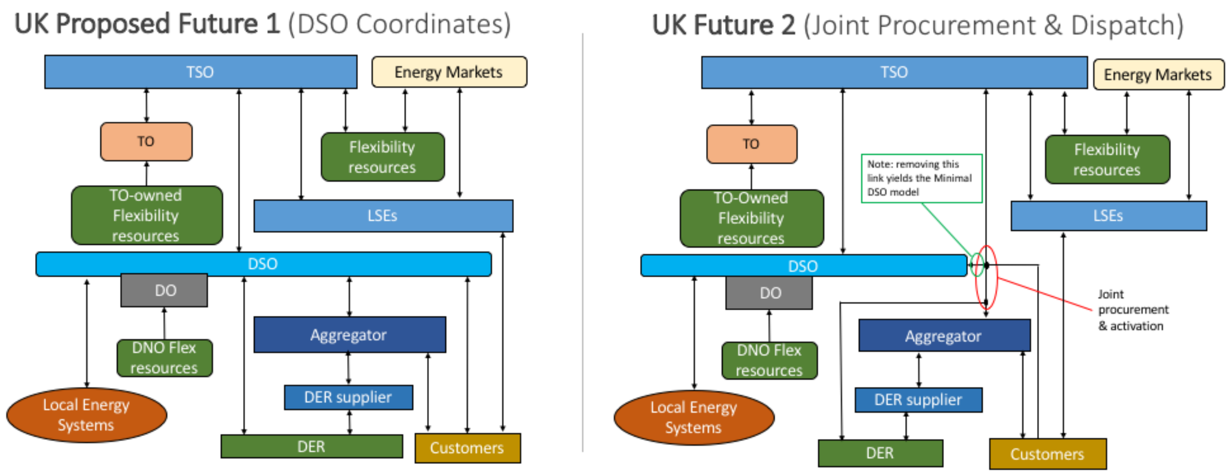

Figure 15: Coordination Framework of Two Future Models in U.K.

At this point in the process, which is still early, there are three main conceptual approaches[31] favoured by two different groups of participants as depicted in Figure 15. National Grid (TSO) favours a "TSO coordinates" approach somewhere between Total TSO and Hybrid DSO (right-hand diagram with the line segment circled in green removed).[32] The TSO would not run the distribution systems but would have direct dispatch and financial relationships with DERs in the context of a TSO market for balancing and flexibility services and, with appropriate information from the DSO, would use the flexibility market to meet needs of both the distribution and transmission systems. As is the case with most US ISOs/RTOs, this is a "current trajectory" approach that just extends current TSO and DO roles and responsibilities into the future.

The DOs, in contrast, advocate a "DSO coordinates" approach, with an expanded DSO role that leans toward the Total DSO, which they argue is needed to ensure reliability and optimal performance of both the distribution system and the DERs themselves. This option is presented on the left of Figure 15. The two largest of UK's DOs, Western Power Distribution (WPD) and UK Power Networks (UKPN) last year released draft strategic plans[33] for stakeholder comment describing their companies' evolution to a DSO. WPD's plan identifies several new functions that it would take on in becoming a DSO, and concludes:

> *"With WPD, as a DSO, managing the co-ordination of services at a local level, the complexity and risk can be reduced for the GB System Operator (GBSO, i.e., the TSO), resulting in a more efficient and cost effective whole system."*

Thus, the DOs are proposing that their role as DSOs include coordinating the flexibility services of DER in their territories, for which they would be the "neutral market facilitator" as a natural complement to

[31] Although the Open Networks Project will compare five new DSO models (plus the status quo), two of the five models are modifications to one the three main conceptual approaches described here, which emphasize DER coordination primarily by the DSO, or by the TSO, or jointly by the two entities.

[32] As described in Section 3 ("Architectural Assessment")

[33] See https://www.westernpower.co.uk/docs/About-us/Our-business/Our-network/Strategic-network-investment/DSO-Strategy/DSO-Consultation-Feedback.aspx (WPD) and http://futuresmart.ukpowernetworks.co.uk/wp-content/themes/ukpnfuturesmart/assets/pdf/FutureSmart-Consultation-Report.pdf (UKPN).

their DO function to ensure that market transactions are electrically feasible. With this view, the WPD strategic plan examines four TSO-DSO coordination models, ranging from one very close to the Total TSO model and one essentially the same as the Total DSO model (“DSO-led market model”), and concludes that the latter will result in the most efficient whole-system outcomes as the numbers of DERs and network constraints increase.

The third main conceptual approach is a “coordinated joint TSO-DSO procurement and dispatch” approach, with a coordination process whereby both entities would directly dispatch or “activate” flexible DER services to meet the needs of their respective systems. This is the right-hand diagram of Figure 15 above, retaining and *emphasizing* the short line segment in the green circle. The providers of DER flexibility services favour this approach because it would allow them direct access to both the DSO and the TSO flexibility markets. However, if the coordinated approach turns out not to be feasible or is not adopted for some other reason, they would favour “TSO coordinates” because they see the TSO markets as a known, transparent system.

The July 2017 Ofgem report clearly supports the evolution of the DOs to become DSOs. However, rather than specify a particular coordination framework it states the dual objectives of; 1) “opening up the delivery of network requirements to the market so new solutions such as storage or demand-side response can compete directly with more traditional network solutions, including as an alternative to reinforcement”; and 2) delivering “mechanisms for transmission and distribution coordination which enable whole system network requirements to be identified and acted upon efficiently, in the best interests of the consumer.”

Benefit-Cost Analysis

There are no benefit-cost analyses available yet, but as noted, the Open Networks Project, led by the UK Energy Networks Association (ENA), is working on this. The plan is to describe several possible TSO-DSO models at the conceptual level, then convene stakeholder workshops to develop details of each model including the roles, responsibilities, and interactions of each of the entities with a primary focus on real-time operations. With these specifications, an independent consultant will simulate each TSO-DSO model to identify issues and problems. This analysis will provide a basis to identify operational and information processes, enabling operational and informational technologies (OT/IT), and related conceptual costs required for a model to function effectively. These benefit-cost analyses are to be delivered by the end of 2018. As noted above, the Open Networks Project is the leading international process for assessing alternative TSO-DSO coordination models with stakeholder engagement.

Primary Reference Documents

UK Power Networks, (2017a) Future Smart: Consultation Report

http://futuresmart.ukpowernetworks.co.uk/wp-content/themes/ukpnfuturesmart/assets/pdf/FutureSmart-Consultation-Report.pdf

This report, Future Smart, sets out UK Power Networks' vision for the Distribution System Operator (DSO) and its view on the roadmap to achieve it.

UK Power Networks, (2017b) Future Smart Conference: Summary Report

http://futuresmart.ukpowernetworks.co.uk/wp-content/themes/ukpnfuturesmart/assets/pdf/FutureSmartConference_SummaryReport.pdf

UK Power Networks hosted a conference on its Future Smart vision. This report summarises feedback from delegates from across government and industry. Their input is meant to directly influence UK Power Network's implementation of its transition to a Distribution System Operator (DSO).

Ofgem (2017), Upgrading Our Energy System: Smart Systems and Flexibility Plan

https://www.ofgem.gov.uk/system/files/docs/2017/07/upgrading_our_energy_system_-_smart_systems_and_flexibility_plan.pdf

The government regulator for Great Britain reports on a number of case studies that are paving the way for peer-to-peer transactions and other market innovations.

Energy Networks Association (ENA) Open Networks Project (2017), *Opening Markets for Network Flexibility: 2017 Achievements and Future Direction*

http://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/14574_ENA_Open%20Networks%20Report_AW_v9_Web.pdf

In this report, the Open Networks project describes options for roles and responsibilities for all parties in future market structures and a whole system approach, including the evolving transformation to Distribution System Operator.

Energy Networks Association (ENA) Open Networks Project (2017), *Commercial Principals for Contracted Flexibility: Promoting Access to Markets for Distributed Energy Resources*

http://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/ON-WS1-P4%20Commercial%20Paper%20(Final%20Draft)-170816-final.pdf

This paper summarises five considerations, which for a time when the NETSO and other entities such as DSOs and Suppliers increasingly procure flexibility services from DER. The focus of this paper is on maximising the use of flexibility provided by DER in the context of enabling them to participate equally alongside other flexibility and balancing service providers.

Western Power Distribution (2017), *DSO Transition Strategy*

https://www.westernpower.co.uk/docs/About-us/Our-business/Our-network/Strategic-network-investment/DSO-Strategy/DSO-Transition-Strategy.aspx

Western Power Distribution sets forth its strategy to transform from a Distribution Network Operator (DNO) to a Distribution Systems Operator (DSO).

4.2 European Union

DER coordination in continental Europe (EU), like many other areas, is in early stage of TSO-DSO coordination development. The European Commission is funding a number of projects to better inform the energy transition to higher renewables and a more distributed system. These projects heavily focus on the concept of a distribution system operator (DSO) that provides both a platform for DER to operate and a way to harness DER services. Industry participants and policymakers acknowledge that DOs[34] will need to play a greater role in providing power system stability and flexibility services, as centralised, synchronous generation is reduced from the supply mix and more generation is connected at the distribution level. The recent publication of the European Commission's Clean Energy Package[35] opened several avenues to raise the profile of the DOs and their role in Europe's energy transition.[36] However, much of the focus at the EU level is on improving inter-regional wholesale market coupling and inter-regional power transfer capabilities. New tools to enable distributed demand flexibility are being developed but the disaggregated and fragmented markets mean that regulatory reform is slow to take root.

That said, over the last five years there have been a range of EU trials that have preceded this package that have focused on the future DSO model. Enhancing the TSO and DSO interface is a key theme from many of these projects, where the coordination, cooperation, transfer of data and roles aim to be more clearly defined, with a focus on how DSOs may provide flexibility and auxiliary services from DER to TSOs and developing tools required to enable these functions.

European Commission legislation sets EU-wide guidelines, but detailed policies and programs are implemented by individual member-states. Germany is highlighted in this section as one of the most advanced EU member-states in terms of the activities being undertaken to implement these guidelines. Germany is the largest power system in Europe. It also has the highest share of renewable power in terms of installed capacity and significant penetrations of DER. In fact, Germany has the third largest amount of installed renewable capacity (excluding hydro) in the world.[37]

Current System Architecture

The electricity distribution business across Europe is very diverse. It varies in the number and size of operational areas, the number of customers, network characteristics, as well as ownership structure.

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[34] EU refers to its Distribution Owners (DOs) using the acronym "DSO." To avoid confusion, this document uses DO to separate the current role of distribution owners from the proposed role in DER coordination as "DSO."

[35] European Commission (2016), *Clean Energy for All Europeans,* online: https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans

[36] Eurelectric (2017), Annual Report, available online: https://cdn.eurelectric.org/media/2520/eurelectric_annual_report_2017-h-CE1D7409.pdf https://cdn.eurelectric.org/media/2520/eurelectric_annual_report_2017-h-CE1D7409.pdf

[37] Refer to https://www.agora-energiewende.de/en/

There are 43 TSOs and approximately 2,400 DOs supplying around 260 million customers within the EU.[38] Five wholesale power exchanges (which operate independently of the TSOs) serve approximately 80% of Europe's load with varying degrees of inter-exchange and inter-country integration. As Europe is a disaggregated market, load is served by retailers that act as balancing responsible parties (BRPs) and under EU legislation have the obligation to keep supply/demand in balance within each settlement period. DSOs will likely play an increasingly important role in the future European grid, and while there is no consensus on what that role will look like, DOs are advocating to play a key role as neutral facilitators of tomorrow's more decentralised energy system.

DOs in Europe have two main functions rooted in the EU's unbundling of electricity services stemming from legislated market reforms implemented in 1996:

1. **System operators**: DOs secure a reliable flow of electricity through their network to their customers. They constantly develop and maintain their networks to ensure that they operate efficiently and with high levels of system security, reliability, and quality.
2. **Market facilitators**: DOs are also required to provide non-discriminatory access to their networks for other system users, like power generators or service providers. They will increasingly move beyond their traditional role of "building and connecting" towards "connecting and managing."

Within the EU the regional TSOs have the responsibility to secure system stability and utilise a range of mechanisms to balance the grid, from balancing markets, re-dispatch, and the curtailment of renewables if required. The EU operates with regional markets that clear locally.

To date, TSOs have led much of the energy transition and efforts to integrate transmission connected and distributed renewable energy as a TSO focused system. However, there is still significant work required to realise the flexibility potential across the EU. The European Commission's Clean Energy Package targets flexibility as a mechanism to enable a distributed power system and marks the start of the large-scale unlocking of demand response (DR) potential in Europe. There is currently 20 GW of activated Demand Response (DR) in the EU, but the European Commission places the potential at 100 GW, rising to 160 GW in 2030.[39] DR markets have been a natural first step for DER to begin to participate outside of retail markets until such time as new, more relevant markets are created. DR markets in the EU are slowly opening up where they were once closed. The role of aggregation is becoming more defined, and market product requirements are becoming more accessible.

As DER becomes more prevalent, DOs recognised the need to take on more responsibilities. For example, European DOs have become increasingly concerned with rising levels of grid constraints leading to congestion on the distribution system, and four existing electricity DSO associations (EDSO, CEDEC, EURELECTRIC and GEODE) recently published a whitepaper called, "Flexibility in the Energy

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[38] Eurelectric (2013), Power Distribution in Europe: Facts & Figures, available online: https://cdn.eurelectric.org/media/1835/dso_report-web_final-2013-030-0764-01-e-h-D66B0486.pdf

[39] SEDC - Smart Energy Demand Coalition (2017), *Explicit Demand Response in Europe: Mapping the Markets 2017*, available online: http://www.smarten.eu/wp-content/uploads/2017/04/SEDC-Explicit-Demand-Response-in-Europe-Mapping-the-Markets-2017.pdf

Transition: A toolbox for Electricity DSOs"[40] which is discussed later in this section. More recently, DOs have provided input on the shape of the future power system and their role and responsibilities within it. In an effort to "ensure harmonisation of national rules at EU level where there are verifiable efficiency gains for the operation of the distribution networks and benefit for consumers," the European Commission has proposed a new entity called EU DSO[41] to include the members of all four existing DO associations and act as the counterpart to ENTSO-e in developing the technical aspects of DER coordination.

Germany has been focused primarily on the role of the TSO in integrating a massive amount of solar PV, 98% of which is distributed.[42]

As a disaggregated market, the German power system has a system of BRPs serving as intermediate aggregators between generators, consumers, power exchanges, and the TSOs. These BRPs can be traditional energy retailers, or energy service companies that are independently aggregating DER. The BRPs in Germany do not physically balance supply and demand in real-time (in contrast to balancing authorities in the US). However, they must ensure their procurement balances supply and load during each market interval (which is currently 15 minutes to 1 hour depending on the market, but which proposed European Commission regulation would reduce & standardise to 15-minute intervals) and are subject to financial consequences if imbalances occur that require intervention by the TSO. This arrangement reduces the balancing requirements of the TSOs and essentially provides incentives for decentralised and local balancing and coordination of resources. These balancing groups are playing an increasingly important role as the penetration of DER grows in Germany. These balancing groups demonstrate one 'rules-based approach' that can be implemented to aggregate DER and demand, incentivise local management, while still taking advantage of wider geographical aggregation effects in the real-time balancing market.[43]

DR in Germany is not as advanced as some other jurisdictions, however, it forms a key component of adding flexibility as part of the European Commission's Clean Energy Package. Currently, the minimum bid size across most markets is 5 MW. In the minute reserve market,[44] exemptions are made for resources/aggregations between 1-5 MW to simplify market access for new players such as DR. Continuing efforts to facilitate DR and flexibility will be important for the future German power system.[45]

Finally, network operators in Germany are currently allowed to curtail 3% of annual production of all renewable generators/DER. While this is implemented mainly for larger scale wind at present, distributed renewables represent 95% of Germany's non-hydro renewable energy generation and the

[40] DSO Committee on Flexible Markets (2018), *Flexibility in the Energy Transition: A Toolbox for Electricity DSOs, available online:* https://www.edsoforsmartgrids.eu/flexibility-in-the-energy-transition-a-toolbox-for-electricity-dsos/

[41] Eurelectric (n.d.), *DSO Entity*, available online: https://www3.eurelectric.org/media/328672/dso-entity-finaldocx.pdf

[42] National Renewable Energy Laboratory (2017), *Evolving Distributed Generation Support Mechanisms: Case Studies from United States, Germany, United Kingdom, and Australia*, p. 15, available online*:* https://www.nrel.gov/docs/fy17osti/67613.pdf

[43] M. Weimar, et al. (2016), *Integrating Renewable Generation into Grid Operations Four International Experiences*, PNNL, available online: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25331.pdf

[44] In other markets, this ancillary service market is called 'primary reserve'

[45] SEDC, 2017.

European Parliament has proposed to phase out priority dispatch of new renewables (including DER) after 2020 because of the over-generation challenge at the distribution level as later discussed. While there is not stakeholder consensus on this change in the curtailment rules, a universal curtailment threshold such as 3% can assist in both setting customer expectations and avoiding over-investment in the network to solve for grid conditions that occur rarely. The European Commission's Winter Package proposed to compensate curtailed renewable generators at 90% of the value of the curtailed energy.

Drivers for Change

At the Paris Climate Summit in 2015, the EU committed to reducing CO_2 emissions by 40%, on 1990 levels, before 2030. To achieve this goal, in June 2016 the European Commission expanded the application of the EU Emission Trading System (ETS) to include sectors not currently within the ETS. Further promises have been made to improve energy efficiency by 30% and to increase the proportion of renewables to at least 27%.

Focussing on Germany, the primary driver for change is the *Energiewende* (German for energy transition). This is a transition to a low carbon, environmentally sound, reliable, and affordable energy supply. This transition was heavily influenced by the Fukushima Daiichi nuclear disaster in 2011 and will see the phase-out of Germany's fleet of nuclear reactors by 2022. Some specific targets are seen in Figure 16.

	2020	2025	2030	2035	2040	2050
Reduction in GHG emissions (compared with 1990)	40%		55%		70%	80-95%
Increase in share of RES in gross electricity consumption		40-45%		55-60%		At least 80%
Reduction of primary energy consumption (compared to 2008)	20%					50%
Reduction in gross electricity consumption	10%					25%
Share of electricity generation from CHP plants	25%					
Reduction of energy use in transport sector (against 2005)	10%					40%

Figure 16: German clean energy targets[46]

While these targets are driving change, Germany also has high electricity prices compared to the rest of the EU and the world.[47] This has accelerated adoption of DER and requires new approaches and more

[46] Refer to https://www.agora-energiewende.de/en/
[47] Refer to http://ec.europa.eu/eurostat/news/themes-in-the-spotlight/energy-prices-2017

economical ways to achieve the *Energiewende* to ensure its success with public approval. New markets and better utilisation of DER are important for this purpose.

Another factor specifically driving more active operation of distribution networks by DSOs is a surplus of distributed energy resources (DER), primarily distributed solar PV. There is also an oversupply of generation in Germany and while larger scale generation is being curtailed, typically wind, more than 95% of renewable energy capacity is integrated in distribution grids, which is more than 114 GW installed capacity in 2017.[48] This amount even exceeds Germany's peak demand which means intervention, control, and curtailment of DER are required. Figure 17 below provides a breakdown of the amount of DER on the low, medium, and high voltage distribution and transmission grids in Germany, as provided by EWE Netz, a German DO.

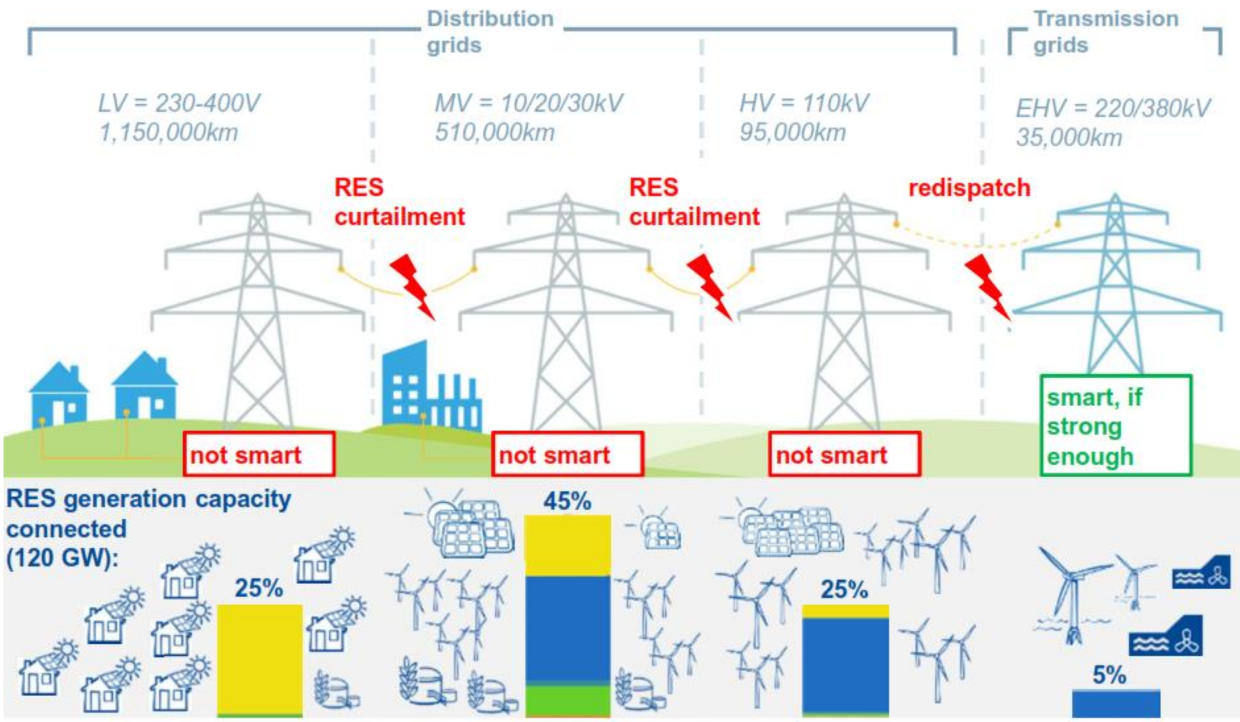

Figure 17: Diagram showing renewable energy generation by connection point at the distribution and transmission level[49]

The German distribution system does not have sufficient observability capability and DER operational controls unlike the transmission system. Additionally, regulations have generally restricted the ability of distributed generation to be curtailed, leaving the curtailment burden exclusively on the 5% of renewable generation connected at the transmission level.

[48] EWE Netz (2017), Challenges and future roles of DSOs in a decentralized electricity system: Trends in the Power Industry in the European Context XII, available online: https://www.cez.cz/edee/content/file-other/distribucni-sluzby/konference-2017/11_merkel_ewenetz_en.pdf
[49] EWE Netz (2017).

Future System

The four existing electricity DO associations (EDSO, CEDEC, EURELECTRIC and GEODE) have become increasingly concerned that EU and member state laws and regulations are out-of-date and need modernisation in order to adequately accommodate the role of DER in Europe's electric system without creating additional risks to distribution system reliability. This group recently issued a joint white paper[50] calling for future EU legislation to specify new roles and functions defining DSOs in enabling flexibility and managing their systems reliably. This white paper represents the most comprehensive roadmap for TSO-DSO coordination produced to date in the EU. One important aspect of this report was the consideration of TSO and DSO congestion markets. Within the EU, there are three different balancing processes. Depending on the balancing process used, DER information can lack locational attributes which influences TSO-DSO coordination model development. In Italy, Poland, and Ireland, balancing services are centrally dispatched, meaning the TSO determines commitments and output as well as directly issues instructions to the majority of resources. In Germany, Portugal, The Netherlands, and Denmark, resources are self-dispatched on a portfolio basis, which means that portfolios of generators follow aggregated schedules of actions to start/stop/increase/decrease output in real-time. In Spain, Belgium, and Norway, resources are self-dispatched on a unit basis, meaning generators follow their own individual schedules to change output in real-time.

Figure 18highlights that the possible structures dependent on available parameters.

[50] DSO Committee on Flexible Markets (2018), *Flexibility in the Energy Transition: A Toolbox for Electricity DSOs,* available online: https://www.edsoforsmartgrids.eu/flexibility-in-the-energy-transition-a-toolbox-for-electricity-dsos/ https://www.edsoforsmartgrids.eu/wp-content/uploads/Flexibility-in-the-energy-transition-A-tool-for-electricity-DSOs-2018-HD.pdf

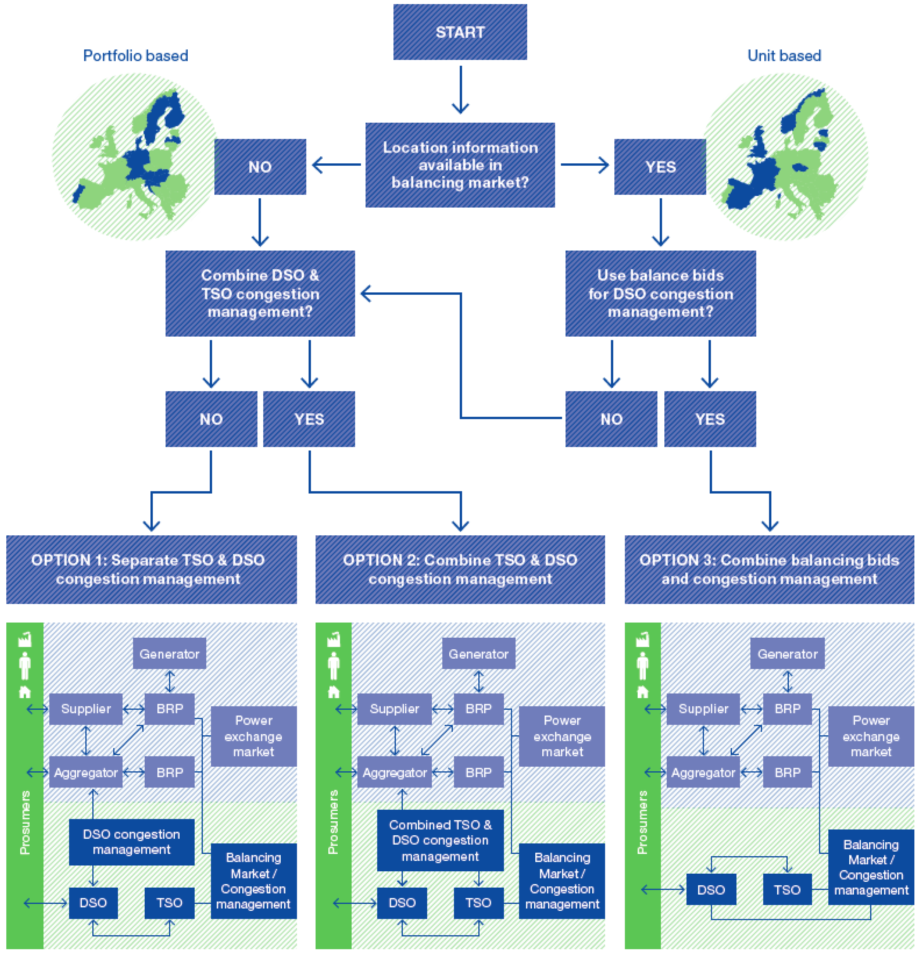

Figure 18: Various market combinations depending on location attributes of DER data[51]

Figure 18, if locational information is available in the balancing bids, there is an option to use these balancing bids for congestion management. These balancing bids are usually only bids for units connected at transmission level and therefore can be ineffective for DSO congestion management purposes.

When DER at the distribution level participates in balancing markets, it is generally aggregated; most markets have a 5 MW minimum bid size. These aggregated bids are not suitable for DSO congestion management purposes because locational information is essential. If aggregations are from a narrower geographic area (which could be possible if participation thresholds are lower and rules dictate circuit, node circuits, nodes, or zones in which aggregations must source DER), then these TSO balancing bids may also offer DSO congestion management opportunities. This event is unlikely at least in the short-term and a separate market for congestion management purposes at the distribution level was recommended by the DSO groups.

[51] DSO Committee on Flexible Markets (2018).

If the locational information is not available, which is the case for many EU member states, balancing bids cannot be used for congestion management purposes. This means that a separate market with its own merit order list must be established. Since it is possible to have separate product specifications for congestion management, independent of the balancing product specifications, it is possible to combine congestion management on transmission and distribution level (option 2). Such a measure could raise the liquidity of the congestion management market. This solution of combining congestion management services between DSOs and TSOs is only possible if the same product specification can be used for solving congestion on the transmission level and on the distribution level. Once a separate congestion management market is established, a product specification for the congestion management services is required. Such a product requires further analysis to fully define. If it is not possible to combine TSO and DSO congestion management markets, separate markets will have to be created (option 1). Each of these options has pros and cons which are presented in the “Flexibility in the Energy Transition: A Toolbox for Electricity DSOs” report.[52]

One TSO-DSO interface tool developed from the EvolvDSO project is a mapping tool of a substation’s capability to provide flexibility to a TSO and provides this as an input to the optimisation problem. These flexibility services can be gained through a variety of resources as seen on the right of Figure 19. The flexibility range of active and reactive power in each primary substation (TSO-DSO interface) is aggregated from each *downstream* distribution circuit (1-4) and the available flexibility and cost conveyed.

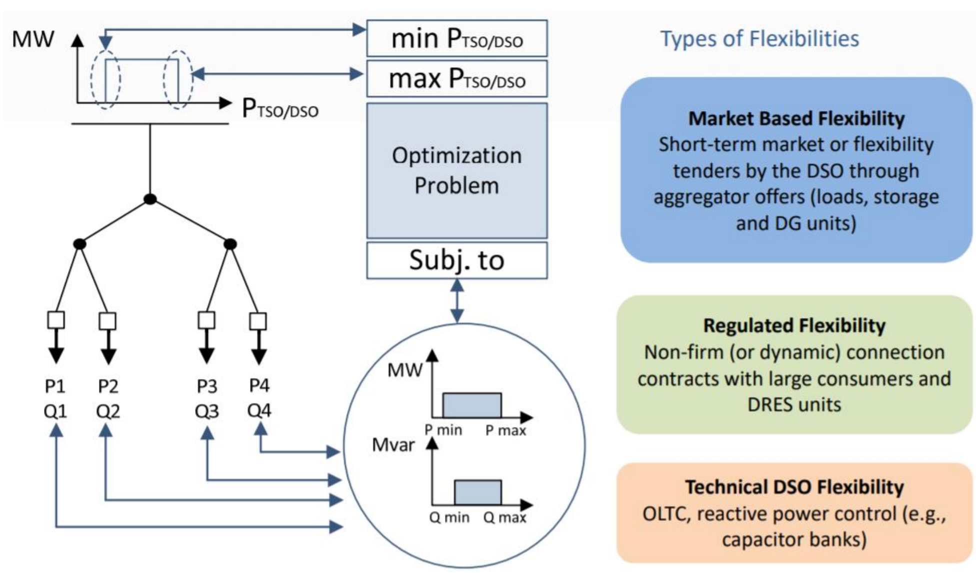

Figure 19: Overview of individual distribution circuit real and reactive power flexibility ranges aggregated for optimisation problem[53]

[52] DSO Committee on Flexible Markets (2018).

[53] Seca, L. (moderator), European Utility Week, available online: https://clarion-european-utility-week-programme.s3.eu-west-2.amazonaws.com/s3fs-public/pdf/Luis%20Seca.pdf

Tools such as these and concepts, such as those discussed show how the EU, is preparing for DSOs to take on more power system critical functions as the power system becomes more decentralised.

Another concept to allow markets to operate across the TSO-DSO interface is a traffic light concept proposed by the four DSO representative groups in the Flexibility in the Energy Transition report.[54] While optimal outcomes can be achieved through a market mechanism, DSOs also need to ensure their system continues to operate safely and effectively without adverse impact from a market trying to solve a competing problem, at the TSO level for example. The DSO traffic light concept provides one way of managing this interaction where the DSO sending green signal informs the market that there is no limitation on sourcing services from the DSO and a red signal from the DSO prevents use of the DER in the optimisation because system stability is jeopardised, and sourcing services is not possible. The report states that in today's power grid, there is only a green phase (operation dictated by the market) that can, in extreme situations, suddenly become red (operation dictated by grid needs). As the transition from one phase to the other becomes increasingly significant in future, it is important to describe an amber intermediate stage. The amber phase, i.e., the interaction of market and grid, is entered if a potential network bottleneck exists in a defined network area. In the amber phase, distribution system operators can call upon the flexibility offered by market parties in that network segment to prevent a red phase situation. This will generally be affected indirectly through measures agreed with suppliers/aggregators or in exceptional cases, should such measures be lacking, direct control as allowed by contractual arrangements.

Italy has implemented a medium voltage DER-shedding function (remote disconnect) through a secure TSO request system. This communication path, as seen in Figure 20 includes the DSO. This provides the DSO with visibility of the request where it also has knowledge of its own grid condition (grid state) to which the TSO may not have full or real-time access. This communication model gives the DSO visibility to the TSO signal but also the ability to block this signal if, in consideration with its current grid state measurement, it may compromise the distribution system. This model aligns with key concepts discussed previously with regard to operation, roles, and responsibilities in the European DSO's envisaged model.

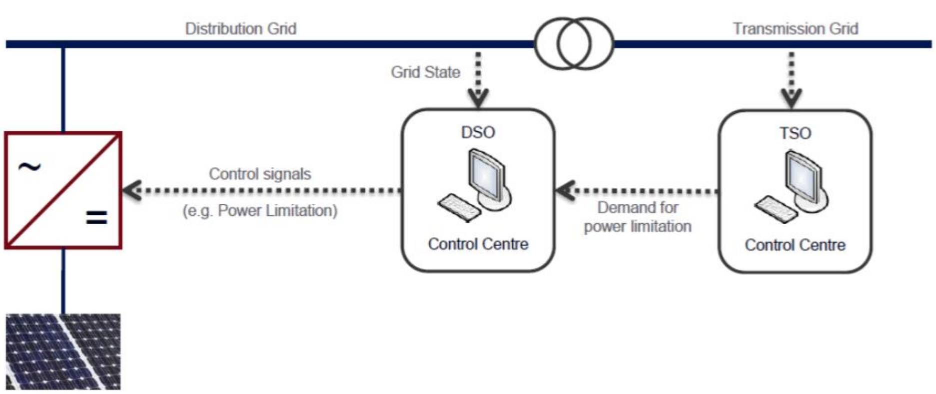

Figure 20: Italian model for TSO control of DER

[54] DSO Committee on Flexible Markets (2018).

In Germany, this concept is called “DSO 2.0.” DSO 2.0 includes both active system managers and neutral market supporters. German DOs need network data to be both active system managers and neutral market supports. German DOs are investing in the controllability and observability of their networks, with state estimation, dynamic load flow scenario calculations, new communications pathways, (powerline communication, 450MHz radio networks), and smart meter deployments as opportunities to enable both aspects of the DSO.

As mentioned previously, there is an oversupply of generation on the distribution network related to DER, which is only increasing. German DOs intend to utilise these resources for flexibility with more than 60 million (40 million EVs, 15 million DR heating units, and 5 million DG and storage) controlled DER by 2050.[55] As part of this function, DOs are looking to have both an automated ‘DSO re-dispatch process’ to operate DER based on minimum cost and a ‘DSO reflag process’ to limit the flexible use of these DER when they can create a system constraint. This solution is very similar to the traffic light concept previously described. Figure 21 presents the future German layered (cascaded) and decentralised structure where balancing and congestion management occurs by the BRP/DSO/TSO at each level as well as holistically. The binary ‘DSO re-dispatch process’ or ‘DSO reflag process’ can effectively switch network levels off from operating in a market if constrained, much like watertight containment compartments on a ship. If one section has a constraint/leak, it is isolated from the remainder. Note also in Figure 21, pumped hydro is neglected as a flexible load to store energy at network level one, which is the primary mechanism used to balance German grid today (pumped hydro storage from Austria).

[55] EWE Netz (2017).

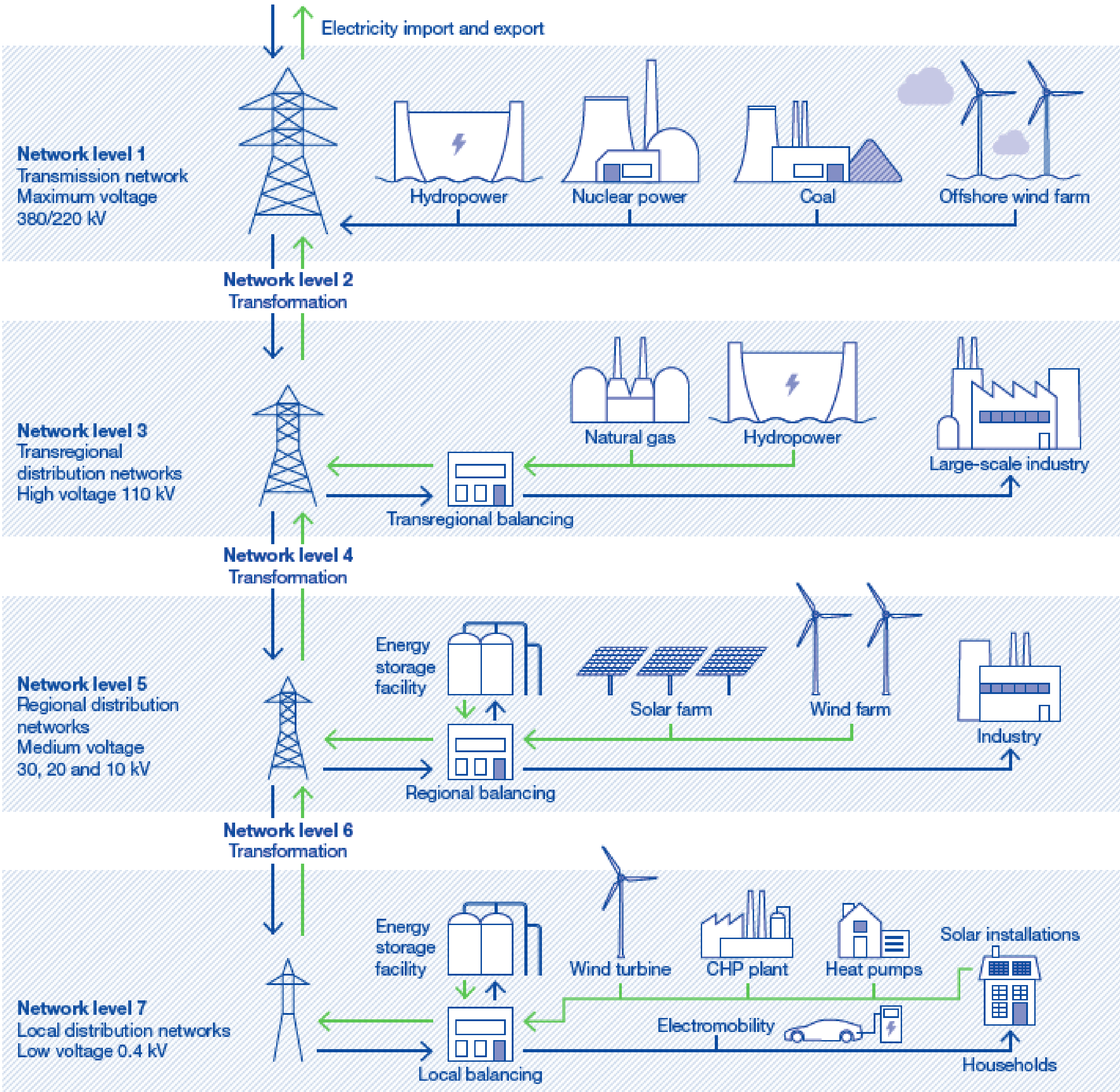

Figure 21: Future German layered (cascaded) and decentralised structure

Primary Reference Document

DSO Committee on Flexible Markets (2018), *Flexibility in the Energy Transition: A Toolbox for Electricity DSOs*

https://www.edsoforsmartgrids.eu/wp-content/uploads/Flexibility-in-the-energy-transition-A-tool-for-electricity-DSOs-2018-HD.pdf

With the European energy transition demanding closer inter-DSO cooperation, the European associations representing DNOs – CEDEC, EDSO for Smart Grids, Eurelectric, Eurogas and GEODE – worked together on this project. This report includes set of solutions to enable DNOs to use flexibility as a tool to operate their grids in a cost-efficient way and also provides recommendations to policymakers on how the regulatory framework should evolve to make better use of flexibility, both by the DNOs as well as by other stakeholders.

4.3 California

Current System Architecture

As background, California has a peak demand of approximately 65 GW with about 40 million residents. The TSO function is provided by an independent real-time market and transmission operator, the California Independent System Operator (CAISO). California is a restructured state, the three primary investor-owned utilities are the transmission and distribution owners and operators (TDOs) and do not own generation. Retail electricity is provided by independent competitive retail energy service providers (Retailers), with about 17% of commercial/industrial load served by competitive Retailers and 20% of retail load served by Community Choice Aggregators[56] (CCAs), the remaining customers are supplied by the TDOs under their provider of last resort (POLR) obligations. These entities are also referred to as Load Serving Entities (LSEs). The TDOs do not make any money on the power sales under the regulatory structure. LSEs' resource adequacy requirements are obligated to meet California renewable energy standard for energy delivered.

DER coordination in California is in transition given the expanded opportunities for DER to participate in the CAISO energy and ancillary services markets, provide resource adequacy capacity and clean energy to load-serving entities (LSEs), and local transmission and distribution non-wires alternative (NWA) services. Figure 22 below[57] illustrates the starting point for the discussions in California. The control and informational interfaces shown reflect current arrangements for demand response resources to participate in the CAISO market.

[56] CCAs in California are expected to serve 85% of customers by 2025

[57] More Than Smart (2017), "*Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid*," June 2017, available online: http://gridworks.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf

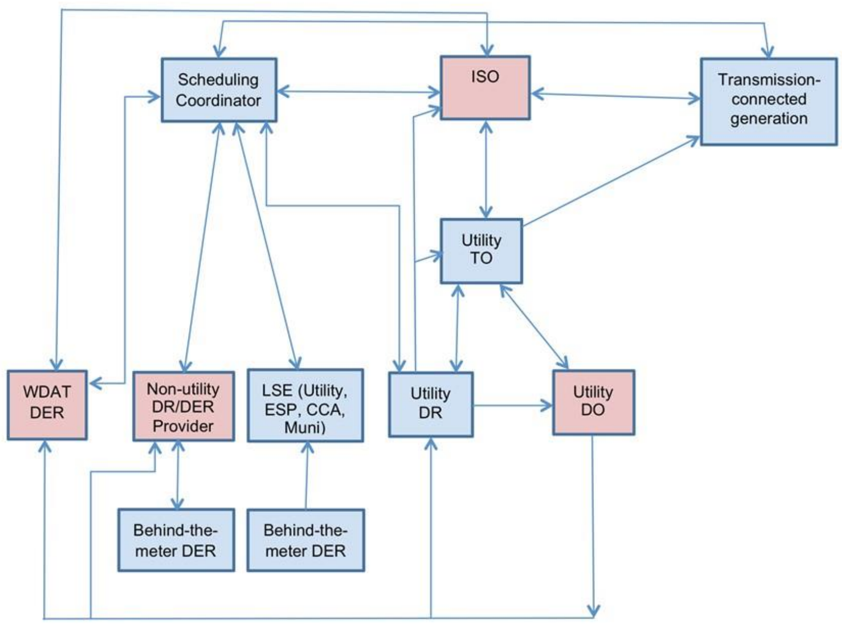

Figure 22: California Control & Information Flows for Demand Response (2016)

In Figure 22 a variety of roles are identified.

- The California independent system operator (CAISO) is responsible for wholesale market operation and transmission operations for most of the state.
- A load serving entity (LSE) is an entity selling retail energy to end customers, including competitive energy service providers (ESP), Community Choice Aggregators (CCA), or investor-owned and municipal (muni) owned utilities. A CCA is a governmental organization with a city/county franchise to be the default retail energy provider.
- The scheduling coordinator is a function in the U.S. markets that is responsible for scheduling and settling energy transactions with the CAISO for next day and real-time adjustments on behalf of LSEs, wholesale suppliers, and DER aggregators. A qualified LSE, supplier, or aggregator can also self-provide the schedule coordinator function.
- The utility transmission owner-operator (TO) is responsible for monitoring physical operation and managing routine and emergency switching for their system under the supervision of the CAISO.
- The utility distribution owner-operator (DO) is responsible for monitoring physical operation and managing routine and emergency switching for outage restoration. In California, each of the three investor owned utilities (IOUs) have the TO, DO and LSE functions within the same utility, but are often physically separated based on regulatory firewalls.
- The Wholesale Distribution Access Tariff (WDAT) DER refers to distribution connected resources that participate directly in the CAISO market similar to transmission connected generation; such resources interconnect to the distribution system under the U.S. Federal Energy Regulatory Commission (FERC)-jurisdictional WDAT.

Real-time coordination of DER in this structure involves a variety of intermediaries interfacing between the CAISO and the DER device. This can in some instances involve 2-3 layers of information and control interfaces to actuate a DER response. For example, a utility demand response (DR) program involves the CAISO calling the utility TO to initiate an action, the TO in turn calls the utility department that manages the DR program, who then initiates a control command that may directly link to a DER device or connects to a device manufacturer's or aggregator's system which initiates a command to the device. In the case of a third-party DR resource, the CAISO's market dispatch issues an instruction to the scheduling coordinator for the resource, who in turn transmits the instruction to the third-party DR aggregator who is responsible for dispatching or controlling the individual customer sites that comprise the DR resource.

Note that there is no role for the utility DO in the dispatch pathways just described. An active DO role was not needed because the DR resources only act to change load behind the customer meters and do not inject energy into the system. The California parties recognize that with the growth of injecting DER and DER aggregations (DERA), they will need to specify an explicit operational role for the DO, because: (1) real-time conditions on the distribution system can constrain the ability of DER to utilize their full capacity, often with little or no advance notice, which creates uncertainty for the CAISO regarding the amount of response to its dispatch instructions it will receive, as well as for the DER provider whose business model depends on being able to respond reliably and predictably to market instructions; and (2) CAISO dispatches, to which the DO has no visibility, can create unexpected reliability problems. While it may be fairly simple to provide effective three-way communications (CAISO-DO-DER) to manage these problems with small numbers of injecting DERs, this arrangement will not scale effectively for large numbers of DERs and multiple third-party DER providers utilizing the same local distribution facilities. Automating a process that does not resolve these structural issues will not solve the fundamental coordination issue.

The existing DR arrangements illustrate just one pathway in the current structure. The larger problems with this architecture are both the inherent multiple layers and the emerging multiple uncoordinated communication pathways among the various entities and DER devices. See Figure 23 below. These communication gaps are further compounded by an open loop control scheme that is formed by centralized DER control (from CAISO through aggregator and utility programs to the individual DER) that bypasses the DO. This structure creates the potential to have uncoordinated dispatch/curtailment instructions that have detrimental reliability outcomes. For instance, it is possible for the CAISO to issue a dispatch instruction to an aggregator to reduce load in a distribution area, and at the same time, a DO to issue a dispatch to a different aggregator with resources in the same distribution area to increase load. Without coordination, these actions will cancel out and create issues for both the CAISO and DO.

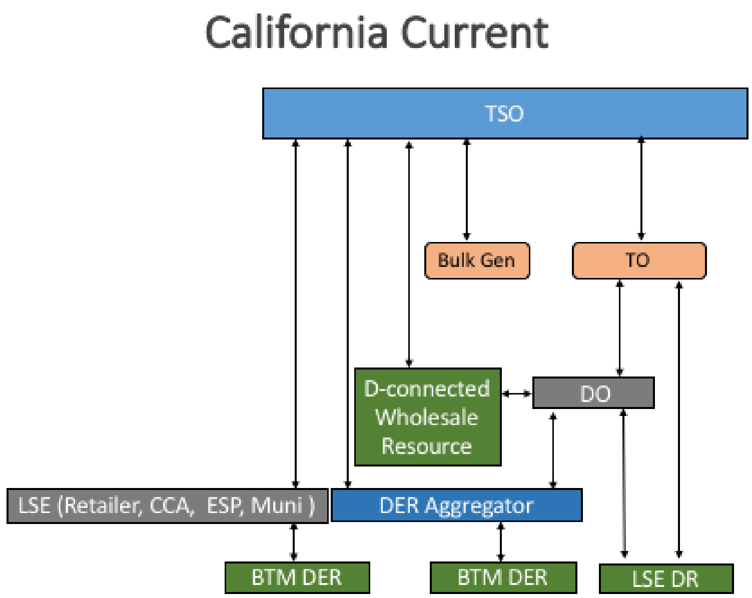

Figure 23: Current California DER Coordination Framework

Based on initial efforts by the utility DOs and the CAISO, the parties foresee major challenges in designing workable procedures to coordinate DER wholesale market participation at scale with distribution system operations. For these reasons and others identified in the Pacific Norwest National Laboratory (PNNL) paper, "Grid Architecture 2,"[58] this current scheme is recognized as not scalable and requires restructuring to better define roles, streamline information flows, and address control architectural flaws in order to orchestrate the very large quantities of active DER forecast in California.

Drivers for Change

California state policies to reduce Greenhouse Gas (GHG) emissions and stimulate growth of DER have led to significant levels of variable and distributed energy resources. These include a 50% Renewable Portfolio Standard, state-wide solar initiative, electric vehicle (EV) incentives, and feed-in tariff procurement for 1-3 MW renewable DG, 1,300 MW energy storage mandate, and net energy metering tariffs as well as $1 billion USD annual expenditure on energy efficiency and demand response programs. Southern California Edison is forecasting DER will comprise about 45% of resource needs by 2025.

Additionally, the state has initiated efforts to utilize DER for wholesale and distribution services that have spurred the DER coordination discussions.

- In 2016, CAISO created a new participation model[59] to allow DER aggregations to provide wholesale energy and ancillary services. The new DER Provider (DERP) model involves a

[58] J. Taft (2016), *Grid Architecture 2*, PNNL, January 2016, available online: https://gridarchitecture.pnnl.gov/media/white-papers/GridArchitecture2final.pdf

[59] CAISO, Distributed Energy Resource Provider, available online: http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx

contractual relationship between the provider or aggregator and the CAISO, and a set of requirements and specifications for the formation and operation of a DER aggregation. Each aggregation must be at least 500 kW in total capacity, cannot include any individual DER that are 1 MW capacity or greater, and may be aggregated across multiple wholesale pricing nodes (T-D substations) as long as the resource's output is consistent with the resource's pre-specified characteristics assessed in the distribution interconnection study.

- The California regulator (California Public Utilities Commission) initiated two regulatory proceedings called Distributed Resource Plan (DRP)[60] and Integrated Distributed Energy Resources (IDER)[61] that will facilitate the use of DER as non-wires alternatives for distribution grid investments.
- The CPUC's Energy Storage proceeding recently established a framework and rules to enable storage resources to participate in "multiple-use applications" (MUA), i.e., stacking of services provided to different entities (CAISO, DO, end-use customer) and the associated revenue streams.[62] The CPUC currently has workshops in progress to develop MUA implementation details including measurement and dispatch priority, and parties generally expect that whatever is developed in this proceeding can be extended to other types of participating DER seeking to enter the market.

Future System Architecture

The future California system architecture has not yet been developed. California started with a focus on resolving near-term needs for operational coordination and integrated planning.[63] Participants in the stakeholder discussions recognized the design of a T-D coordination framework is inseparable from design of future roles and responsibilities. They also recognized that near-term coordination enhancements under the Hybrid DSO model are necessary to streamline and incorporate the utility DO into the information flows and control interfaces as DER and DER aggregator (DERA) begin to enter the wholesale market, as shown in Figure 24. However, these proposed improvements remain workable only for small numbers of DER given the limited coordination and lack of sufficient DER and distribution grid visibility, controls, and automated interfaces between the CAISO, DERAs, and the DOs. As such, the current state is not scalable to address California's forecasted DER growth and market participation in the next decade.

One example of the more complex coordination issues California expects it will need to address with greater DER volume is how to allocate distribution capacity reductions among multiple DER providers whose market participation relies on the same local facilities. The open access rules the CAISO implements through the wholesale market dispatch do not yet have an analogue on distribution. Combined with the fact that abnormal circuit configurations are exponentially more numerous on distribution than on transmission, this policy gap creates unmanageable uncertainties for both DER providers and the CAISO. Under the current Hybrid DSO trajectory, the utility DO would have to provide

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[60] CPUC Distribution Resource Plan (DRP) Proceeding, available online: http://www.cpuc.ca.gov/General.aspx?id=5071

[61] CPUC Integrated Distributed Energy Resources (IDER) Proceeding, available online: http://www.cpuc.ca.gov/General.aspx?id=10710

[62] CPUC Decision on Multiple-Use Application Issues, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M206/K462/206462341.pdf

[63] More Than Smart (2017), "*Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid* ," June 2017, available online: http://gridworks.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf

timely information to all DER and DERA affected by a circuit reconfiguration with sufficient accuracy to enable each DER to know how much energy or capacity it can bid into the CAISO market and for the CAISO to have confidence in the amount of response it will get at each pricing node to its market dispatches. Because the Hybrid DSO model makes the DO essentially a supporting player with no role in the transactions between DER and the CAISO, these uncertainties will be increasingly difficult to mitigate as the volume of DER increases.

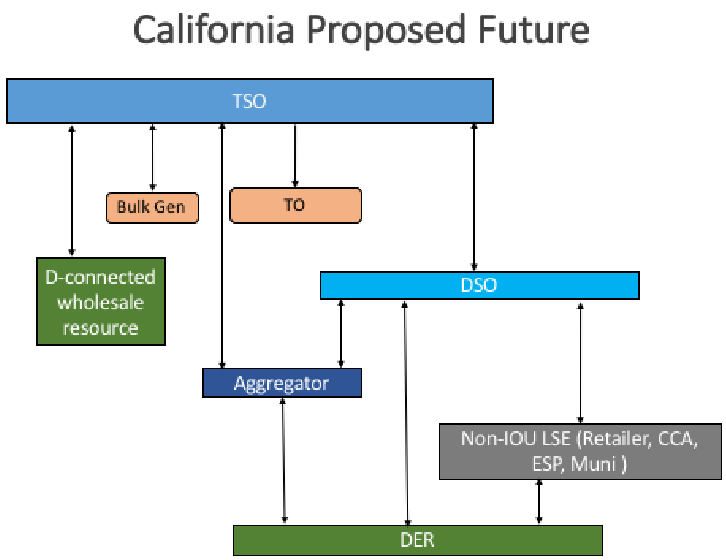

Figure 24: California Possible Future Hybrid Coordination Model

As such, further informal discussions are underway to consider alternative coordination architectures for the longer term in California. The layered structure, illustrated in Figure 24 above, is an extension of the current model and may be a potentially viable approach. DER providers prefer this approach as it maintains a direct access to wholesale markets. However, it is not clear that this model will scale to meet California's DER growth expected to exceed 40% of system peak by 2025 and regulatory requirements for expanded use of DER services for wholesale and distribution network services. As such, an alternative approach discussed by the CAISO and the TDOs is a more completely layered model similar to the conceptual Total DSO model.

So, while the DOs are evaluating taking on this role, DER providers and other stakeholders have discussed creation of an independent DSO (under the Total DSO model) analogous to the relationship between the CAISO and the participating utility TOs. However, it is unlikely that these discussions will evolve very far until the California regulator decides to take up the issue, which may not happen until after 2020 when dispatchable DER (e.g., energy storage) reaches material levels and California replaces net energy metering tariffs for customer solar PV with tariffs that enable customers to sell excess energy. Net energy metering tariffs in California do not allow the customer to sell excess energy from their solar PV system. The energy produced by their PV system is measured and the quantity subtracted from the energy they consumed on their monthly bills. Any actual net power flows from the customer's system into the distribution system are considered inadvertent energy under net energy metering tariffs.

Primary Reference Document

More Than Smart (2017), *Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid*

http://gridworks.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf

This report discusses the implications of a "high-DER" grid whereby operators of the transmission and distribution systems will need to coordinate and communicate with each other in new ways to maintain reliable operation of their respective systems and, ultimately, of the electric system as a whole. This report draws on perspectives from multiple industry participants and stakeholders across California to identify needs and develop interim recommendations toward developing a high-DER T-D coordination framework. This paper identifies some of the operational considerations for accommodating growth of DER on the electric system and enabling DER participation in markets.

4.4 New York

Current System Architecture

As background, New York has a peak demand of approximately 34 GW with about 20 million residents. Its TSO function is provided by an independent real-time market and transmission operator, the New York Independent System Operator (NYISO). New York is a de-regulated state, the five investor-owned utilities are the transmission and distribution owners and operators (TDOs) and do not own generation. Retail electricity is primarily provided by independent competitive retail energy service providers (Retailers), with about 80% of commercial/industrial load and 20% of retail load served by Retailers, the remaining customers are supplied by the TDOs under their provider of last resort obligations. The TDOs do not make any money on the power sales under the regulatory structure and are obligated to procure resources to meet the POLR customers' demand including the New York renewable energy standard requirements.

NYISO anticipates enabling aggregations as small as 100 kW to participate in wholesale markets for energy, ancillary services, and capacity[64], but with some notable differences from California. NYISO plans to require these aggregations to be entirely within a single pricing node. Additionally, DOs in New York have been developing innovative contract-based procurement models for DER to provide distribution-level services, avoiding costly new upgrades to the legacy infrastructure. And, the NYISO and DOs have had discussions to implement rules for DER service hierarchy to ensure that the responses to competing signals DER may be receiving are well orchestrated.[65]

Currently, DER market participation is limited because of the 1 MW minimum individual resource injection requirement for full participation. Programs currently available are illustrated in Figure 25 below.

[64] Unlike California, NYISO clears most capacity through wholesale markets (in California, the majority of capacity is bilaterally contracted).

[65] New York has an open stakeholder engagement process to address a range of detailed issues including DER coordination. The Joint Utilities of New York stakeholder engagement website with materials is here: http://jointutilitiesofny.org/joint-utilities-of-new-york-engagement-groups/

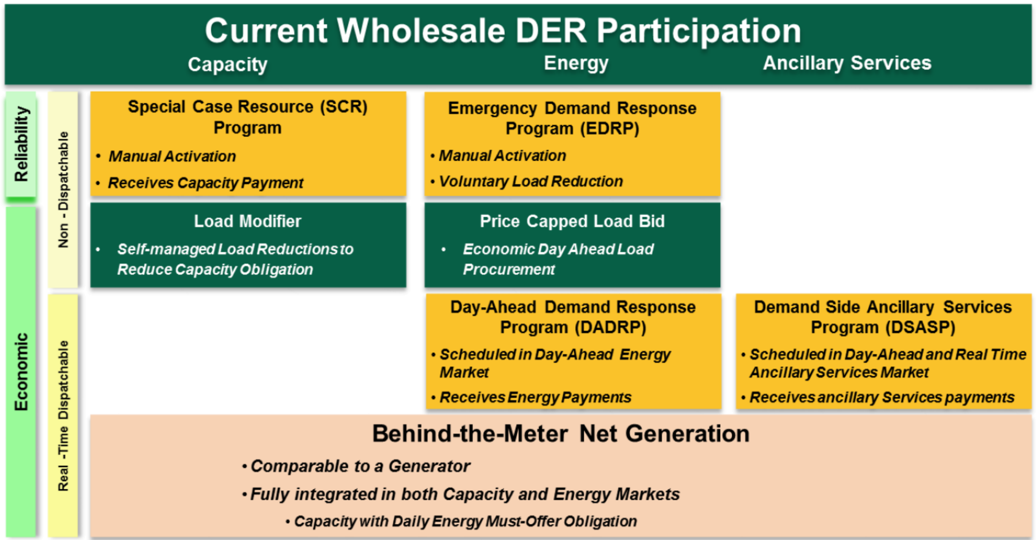

Figure 25: Current programs for DER market participation in New York[66]

New York is also one of the most advanced regions in the world for enabling DER to provide non-wires alternatives services for the distribution system. ConEdison, the largest New York TDO, has had several competitive procurements to source DER services to defer large distribution capital upgrades. This effort includes the $1 billion USD Brooklyn-Queens Demand Management (BQDM)[67] program. Additionally, the other New York TDOs have begun conducting pilot programs to source DER for distribution non-wires alternatives at the direction of the New York regulator[68] under the Reforming the Energy Vision (REV) initiative. This effort includes the development of platforms to facilitate the availability of procurements and conducting the procurements.[69] This dual use of DER for NYISO wholesale markets and TDO distribution services has created a need for coordination. Existing rules require generators in New York to send data through the appropriate TDO to the NYISO. As shown in Figure 26, most DR operates via aggregators, but a few large DG (>500 kW) connect directly to the NYISO.

[66] NYISO DER Roadmap, January 2017, p.11. http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/DER_Roadmap/DER_Roadmap/Distributed_Energy_Resources_Roadmap.pdf

[67] ConEdison (n.d.), *Brooklyn Queens Demand Management Demand Response Program,* available online: https://www.coned.com/en/business-partners/business-opportunities/brooklyn-queens-demand-management-demand-response-program

[68] New York State (n.d.), *DPS – Reforming the Energy Vision*, available online: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

[69] ConEdison (n.d.), Non-Wires Solutions, available online: https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions

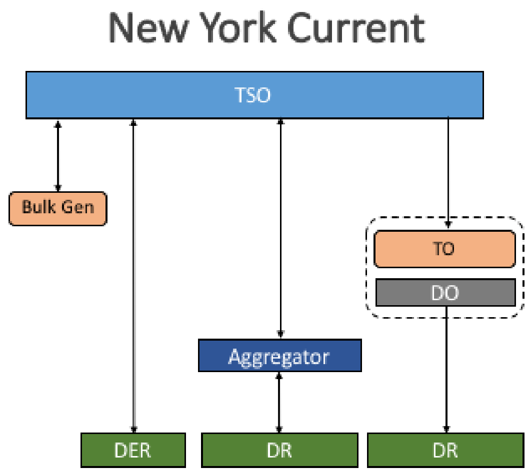

Figure 26: New York's Current DER Coordination Framework

Drivers for Change

In 2014, New York launched the REV, which laid out a comprehensive energy strategy for implementing major reforms to New York's electricity industry.[70] This vision was established as an effort to help consumers make more informed energy choices, develop new energy products and services, protect the environment, and create new jobs and economic opportunities in the state. Additionally, in the wake of Superstorm Sandy (2012), New York demonstrated a tremendous amount of interest in for the role of DER in enhancing the state's grid resiliency.

The REV plan lays out an aggressive set of goals, including 40% reduction in GHG emissions from 1990 levels by 2030 and an 80% reduction in GHG emissions by 2050. The plan also calls for 50% of generation to come from renewable energy resources and a 23% reduction in building energy consumption levels versus 2012. Figure 27 shows the objectives of the NY REV that are driving New York's DER integration efforts.

Figure 27: NY REV's Drivers for Change[71]

[70] New York State, Reforming the Energy Vision, available online: https://rev.ny.gov/

[71] Ibid.

The vision also lays out aggressive goals to improve consumer choice, lower costs, and enhance resiliency. The plan aims to lower costs by reversing the decline in system load factor from 55% in 2015 to previous levels of around 59% as it was in 2005. The NY REV puts emphasis on the role of new grid technology to improve the resiliency of the electric power system by:

- Enabling utilities to earn returns by advancing markets for energy efficiency and DER (thus accelerating the transition to clean energy)
- Deploying price signals that reward investments that improve overall system efficiency
- Aligning the regulatory system to catalyse and leverage innovation, technology advancement, and private investment

As part of REV initiative, the TDOs have begun to expand their pilot programs to source DER services as non-wires alternatives. These opportunities are driven by changes in the distribution planning process that are underway. The NY regulator is also considering changes to the net energy metering tariffs that would allow DER to export energy as a service in the early 2020s under new DER tariffs. This alteration will likely lead to retail energy transactions that require greater coordination. Also, the NYISO market expansion implementation is not beginning until 2019 as illustrated in Figure 28. This figure shows the NYISO's anticipated timeline and milestones necessary to prove its ability to orchestrate DER. A similar roadmap for the TDOs is embedded in their supplemental distribution system implementation plans (DSIP)[72], but no holistic view for integrating the NYISO and TDO roadmaps has yet been developed.

[72] Joint Utilities (2016), *Supplemental Distributed System Implementation Plan*, available online: http://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf

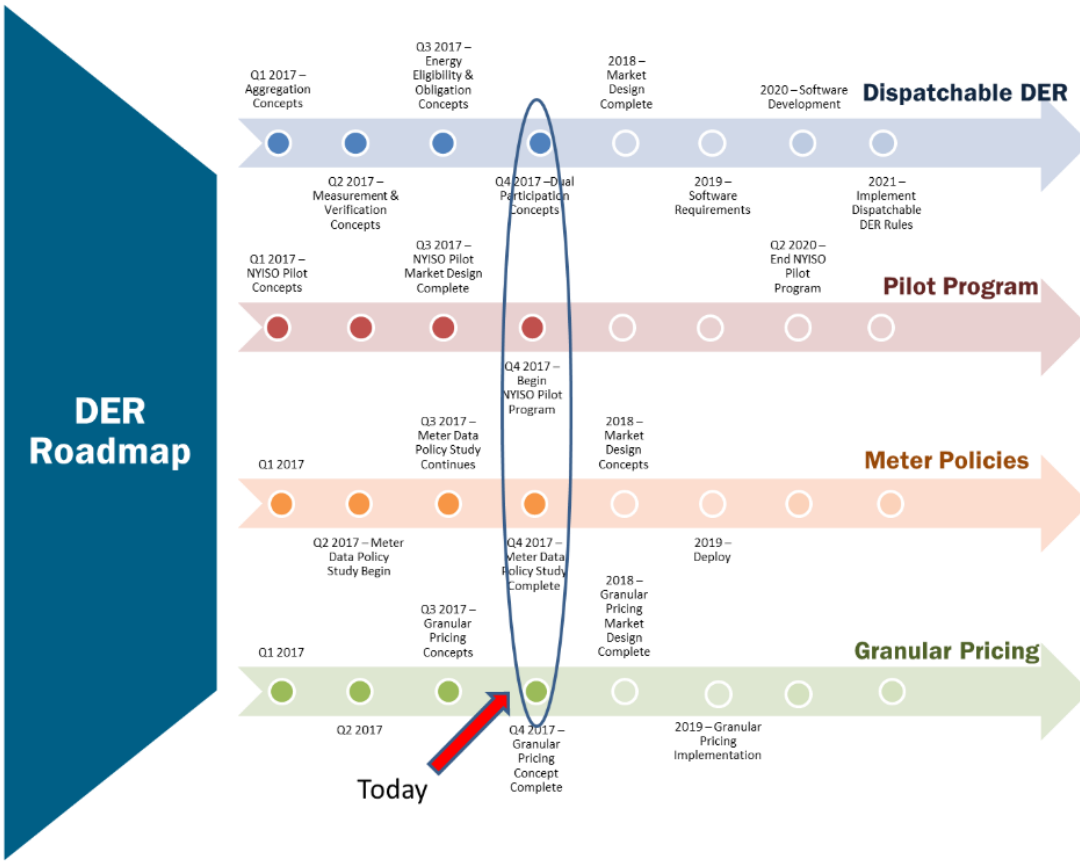

Figure 28: NYISO's 2017 DER Roadmap

Future System Architecture

The future New York system architecture has not yet been fully developed, much like other power systems around the world. However, the state government including the New York state regulator, NY Department of Public Service (NY DPS), has been taking a series of steps to direct the transition and clarify requirements. This includes early on in 2014 defining the role of the TDO as a distribution system platform provider (DSPP):

> *"Distribution utilities* [TDO] *will play a pivotal role, representing both the interface among individual customers and the interface between customers and the bulk power system. The utility as Distributed System Platform Provider (DSPP) will actively coordinate customer activities so that the utility's service area as a whole places more efficient demands on the bulk system, while reducing the need for expensive investments in the distribution system as well.*

> *The function of the DSPP will be complemented by competitive energy service providers; both generators of electricity and retailers of commodity will expand their business models to participate in Distributed Energy Resources (DER) markets coordinated by the DSPP."*[73]

A DSPP in this model is synonymous with a DSO. Note that the NY regulator only has jurisdiction over retail energy and distribution service. The FERC has jurisdiction over the NYISO wholesale markets and transmission service. In the definition above from 2014, the NY regulator was describing "DER markets" as the development of non-wires alternatives for distribution and ultimately energy markets on distribution. Subsequently, the NY regulator placed less emphasis on the distribution energy market creation and instead on the non-wires alternatives. The NY regulator also ruled that the TDOs would initially be the DSO, but it left open the possibility to revisit the prospect of an independent DSO if the TDOs could not perform the role as expected.

However, market evolution in New York is moving slowly and as such discussions between the NYISO and the TDOs have been relatively limited. To-date market and operational coordination issues have been addressed on an ad hoc basis as the NYISO expands DER opportunities and the TDOs increase the use of DER for distribution network services. These changes to coordination will address near-term needs but certainly will not be the "end state" system architecture to support NY's vision.

An example of a near term step is to develop the participation mechanisms for aggregated DER. NYISO has proposed to reform their participation mechanisms for behind-the-meter DER to provide a broader range of services than was previously possible. The proposed participation mechanisms broaden definitions for existing programs, adds new programs, and creates two tiers of aggregations. These tiers, as illustrated in Figure 29 below, are: 1) DERs that are 1 MW and larger, and 2) aggregations that are between 100 kW and 1 MW DERs.

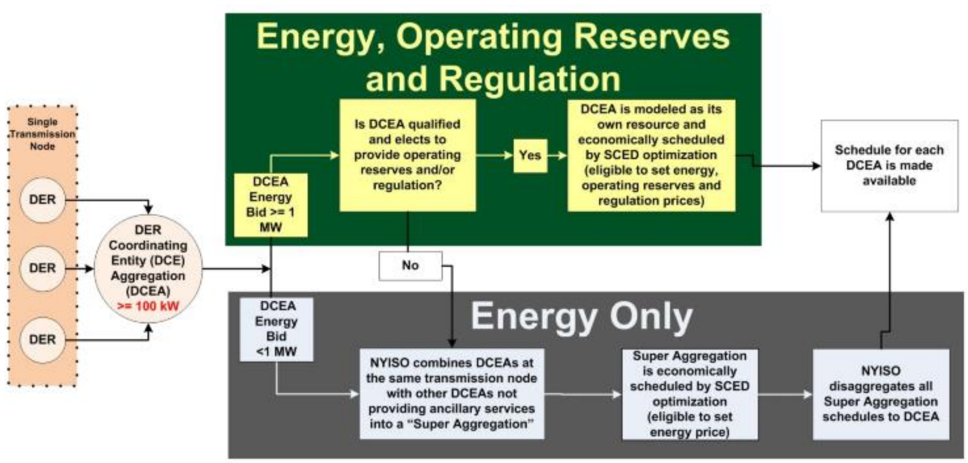

Figure 29: Concept for DER aggregation (DCEA) participation in energy, capacity and ancillary services[74]

[73] NYS Department of Public Service Staff (2014), *Reforming the Energy Vision*, available online: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5A9BDBBD-1EB7-43BE-B751-0C1DAB53F2AA%7D

[74] NYISO (2017), *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets, A Report by NYISO*, available online: https://home.nyiso.com/wp-content/uploads/2017/10/Distributed-Energy-Resources-Roadmap-DER.pdf

The NYISO market participation obligations are the same for resources above or below the 1 MW threshold. However, resources smaller than 1 MW are rolled up into "Super Aggregations" within each node solely for the purpose of determining the daily award schedule (e.g. without affecting the individual obligations and rights of the smaller aggregations).

Under the NYISO plan, DER would be able to provide wholesale market services in addition to distribution level services and retail services. Figure 30 depicts the NYISO's conceptual coordination model as described in its DER Roadmap.[75] Note that the DSP entity in the figure refers to the TDO as a DSO, and "retail services" refers to non-wires alternatives and distribution grid services, such as reactive power. The use of "wholesale" and "retail" also refers to the separation of federal (FERC) and state regulatory (NY DSP) jurisdiction. The model below is consistent with the NY regulator's view of the role of the TDO as a DSP/DSO.

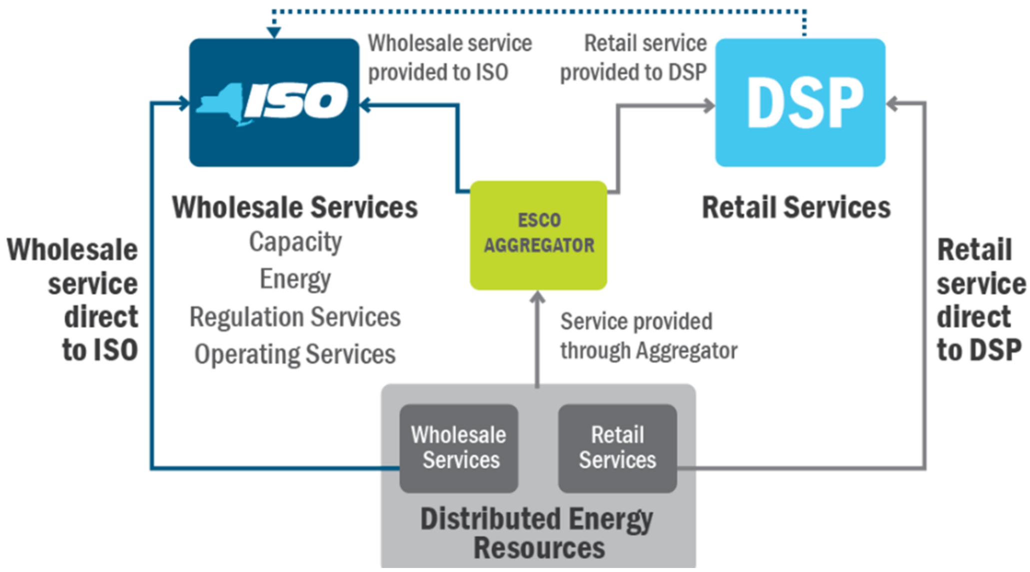

Figure 30: NYISO's DER Roadmap Concept Proposal for future system architecture

The NYISO and the TDOs are still studying the issue of how to implement metering, telemetry, and communications for DER aggregations. The NYISO's basic premise is that telemetry requirements should be the same for all resources participating in energy markets. In other words, they intend to maintain a six second requirement for telemetry of all resources. However, this is a nuanced point, because from the NYISO's perspective, this six second requirement applies to each *aggregation*, not each individual DER. The NYISO is comfortable with interpolated longer period signals from individual DERs. For example, individual units might send 30 second signals, with the aggregator providing a blended, interpolated faster signal at the nodal level. The NYISO intends to develop a verification process to ensure that the blended signal is an accurate reflection of the individual DERs in aggregate. It is also possible that the NYISO may audit or ask for a revenue grade meter on a longer time horizon (hourly, 15 minutes, etc.) for sample sets of individual DERs.[76]

[75] Ibid.
[76] DeSocio, M. (2018). Interview with Mike DeSocio, Senior Manager, Market Design, NYISO.

NYISO will also require aggregators to account for operational restrictions for DER in an aggregation as well as the distribution system to which the DER is connected. TDOs are also imposing operational restrictions as part of the interconnection process. TDOs anticipate that a notification and coordination process will be implemented in which aggregators notify the TDO of day-ahead awards with sufficient amount of time for the TDO to validate whether the dispatch instruction provided by the NYISO is valid and executable based on any operational contingencies/restrictions that may exist within the distribution system.

Primary Reference Documents

NYISO (2017), *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets, A Report by NYISO*

https://home.nyiso.com/wp-content/uploads/2017/10/Distributed-Energy-Resources-Roadmap-DER.pdf

This DER Roadmap provides a guide to inform wholesale market design, planning, and operation for DER wholesale market integration.

NYS Department of Public Service Staff (2014), *Reforming the Energy Vision*

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5A9BDBBD-1EB7-43BE-B751-0C1DAB53F2AA%7D

This document is the Staff Report and Proposal that provides a framework for the NY REV, answering the questions about the role of distribution utilities and market design to meet the broader state policy objectives.

4.5 Japan

Current System Architecture

Japan is in the midst of reforming the electric industry, which currently comprises of ten vertically integrated electric utility power companies (EPCOs), nine of which regionally serve mainland Japan (the tenth EPCO serves the Islands of Okinawa). The first round of electricity market reform commenced in 2013 with the establishment of the Organization for Cross-Regional Coordination of Transmission Operators (OCCTO). See Figure 31. OCCTO is the TSO for mainland Japan responsible for the countywide network planning and operations.

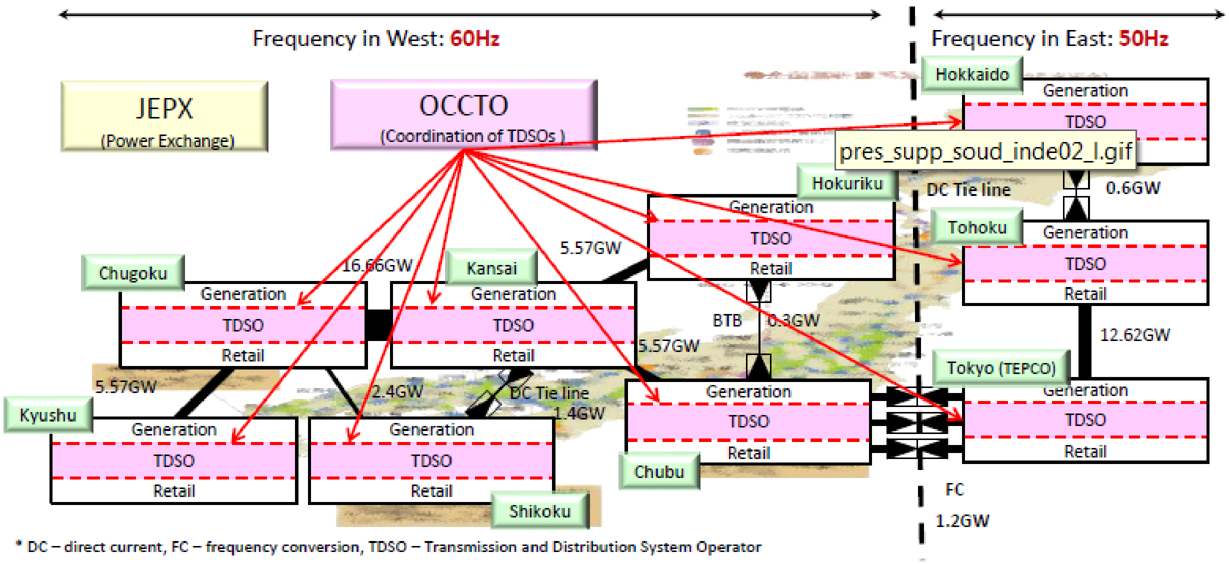

Figure 31: The OCCTO, established in 2013, coordinates the TDSO's across the nine mainland Japan regions.

The TSO combines and analyses the supply-demand (annual, monthly, weekly, and day-ahead) plans submitted by each EPCO and ensures planning criteria are met. Based on the longer-term plans, the TSO may instruct an EPCO to modify or construct generation or transmission lines. As the national balancing authority, the TSO may instruct interregional exchange of power.

The second step in market reform occurred in 2016 with residential and small commercial retail competition (customers less than 50 kW demand). Partial retail competition started in 2000 for large customers (greater than 2,000 kW) and in 2004 for customers greater than 500 kW. The retail energy providers are responsible for procuring sufficient supply to meet their forecasted demand, which are planned and operated by the retailers in 30-minute windows. The majority of the supply contracts are procured in the wholesale power generation market, the Japan Power Exchange (JPEX). Retailers will communicate the supply-demand plans to the TSO. The TSO has the operational responsibility to aggregate each region's plans and operations to ensure a stable grid nationwide.

The final step in the market reform will occur in 2020 when the transmission and distribution part of the EPCOs must legally separate from the utility generation business and unregulated retail energy provider. The resulting transmission and distribution owner and operator company is called TDSO as the entity is both the owner and the system operator for their respective regional balancing areas. As such, DER coordination within the current grid architecture is managed by the TDSO under a federated model that is overseen by the national TSO (OCCTO).

Japan experienced significant growth of DER with the creation of the Feed-in-Tariff (FIT) program in 2012, which paid customers with solar 2.5 times the retail rate for energy exported to the grid. Solar is the leading technology choice of FIT systems, amounting to 32 GW of solar capacity (versus 0.79 GW of wind), compared to a nationwide peak demand in fiscal year 2016 of 156 GW.[77] Bulk system excess (solar) energy quickly manifested itself in certain regions of Japan forcing the EPCOs in Kyushu, Shikoku, Chugoku, Tohoku, and Hokkaido calling a moratorium on interconnection of FIT systems.[78] Japan has yet to observe any significant local impacts from the high penetration of FIT systems. In 2014, the FIT program rules were revised to allow the system operators to curtail FIT systems up to 360 hours a year without compensation. Additionally, once an "Acceptable Maximum PV Capacity", as defined by each region, is exceeded, the FIT systems interconnected in excess of the maximum PV capacity threshold are subject to unlimited, uncompensated curtailment of the exported energy by the TDSO to maintain grid stability.

To enable curtailment for system balancing, Japan developed an output curtailment system. Four options were developed: 1) a dedicated communications line (i.e., fibre) line for higher voltage facilities with day-ahead notification of curtailment, 2) scheduled curtailment day-ahead for smaller facilities, 3) scheduled curtailment day-ahead through an aggregator, or 4) scheduled curtailment annually in areas absent a means to communicate with the utility. The method that is implemented is dependent on the size of the facility and the TDSO, as the maturity of the control solutions vary between regions.

The development of the four options is based on the following considerations:

- Available technology and cost relative to the facility capacity
- Curtailment mechanism should allow for adjustable active power limits to minimize excess curtailment and ensure system stability
- Energy self-consumed on-site should not be curtailed
- The FIT facility and the curtailment system should be flexible to handle future system conditions, including the capability to provide value-added services through aggregators
- When using an internet connection, appropriate cybersecurity measures must be taken

Figure 32 details the basic structure for a solar PV system with curtailment capability. Generally, this capability applies to any system installed in excess of the PV capacity threshold for curtailment up to 360 hours annually; however, each region is at varying stages of curtailment controls implementation. Each facility contains a power control system (PCS), in a broad sense, which includes an output curtailment unit and a controller. The fixed curtailment schedule is acquired by the output curtailment unit through a modem via the internet (or other means of communication). Narrowly defined, the PCS interprets the acquired curtailment schedule and commands the PV system to curtail in accordance with the schedule. These two modules can be combined by a manufacturer into a single piece of equipment.

[77] Organization for Cross–regional Coordination of Transmission Operators (OCCTO), (2017). *Aggregation of Electricity Supply Plans Fiscal Year, 2017*, available online: https://www.occto.or.jp/en/information_disclosure/supply_plan/files/supplyplan_2017.pdf

[78] Ishii, Hideo Ph.D. (2017), *System Architecture & OpenADR Applicability in the Japanese Integrated Grid*. OpenADR DER Tutorial and Workshop, April 18-19, 2017. P. 13.

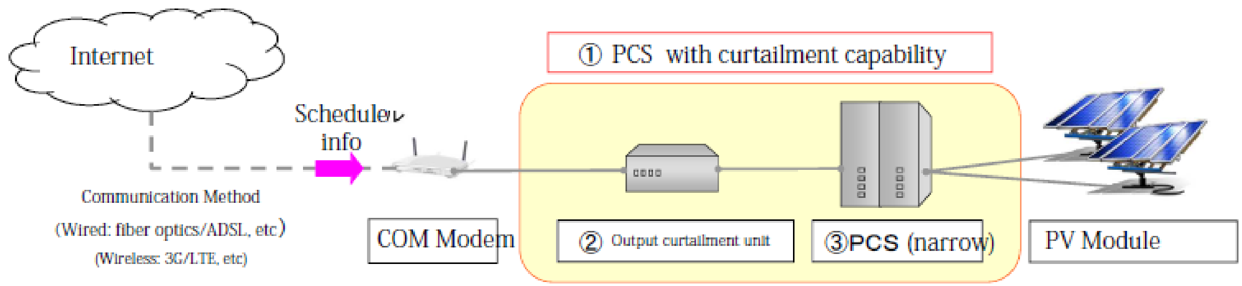

Figure 32: Local communication structure of the output control mechanism for DER

Figure 33 below illustrates the high-level control architecture for effectuating DER curtailment on a day-ahead basis for small-scale facilities. The basic information and control flow is a three-step process: 1) TDSO (today known as the utility in Japan) notifies power producers of output curtailment at least one day in advance, 2) TDSO uploads a curtailment schedule based on the actual day's forecasted power supply and demand, which is provided to the TDSO by the retail providers, and 3) the PCS acquires the curtailment schedule from the server and curtails the facility output accordingly.

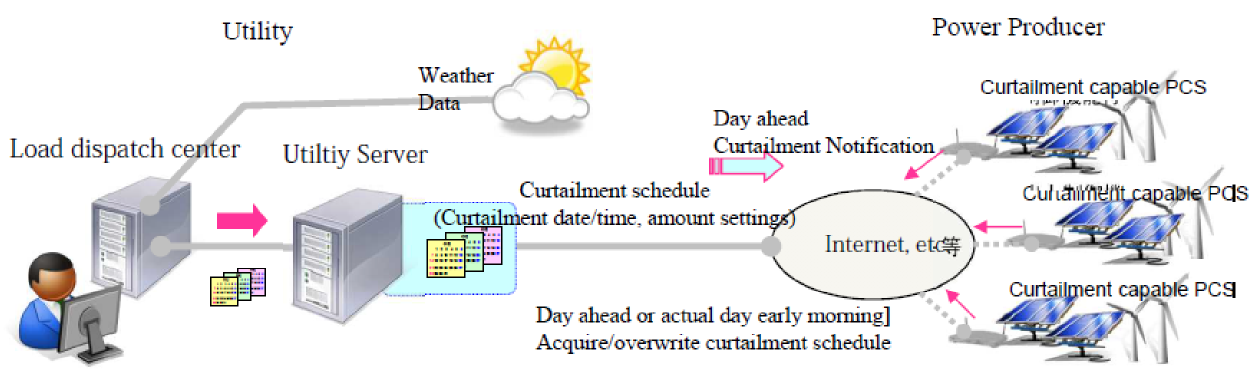

Figure 33: High-level DER output control scheme architecture[79]

The frequency of curtailment commands is developed by each TDSO based on supply and demand forecasts. However, the frequency that the curtailment schedule is modified or overwritten to the utility server may vary from utility to utility. For most installations, the communication medium to effectuate curtailment will be the internet. Though the use of internet for communication is versatile and economical, it requires additional cybersecurity measures. This same architecture is used for aggregators and virtual power plants but instead of communication directly to the solar PV system, the utility server communicates directly with the aggregator, who in turn initiates the commands directly with the solar PV system.

[79] Available online: http://www.kyuden.co.jp/var/rev0/0108/2905/afv7iujeh.pdf (Figure translated to English)

Figure 34: DER output control scheme without remote communications

Figure 34 shows the high-level architecture for power producers without the means to communicate remotely. This solution is tailored to rural customers. In this arrangement, the utility prepares the curtailment calendar for the entire year on an annual basis, and the power producer manually incorporates the curtailment schedule into the PCS (i.e., a truck roll). Although this method allows curtailment for rural areas, which is critical for system stability, it may result in sub-optimal dispatch of resources.

All PCS' must be capable of adjusting the active power output in 30-minute time periods and in 1% increments. For FIT systems that self-consume energy on-site, the PCS must be capable of switching to non-export mode in the event that the curtailment command would reduce active power below the energy needed to supply the on-site load.

Though some regions are further along than others in implementing curtailment controls, Japan's government has organized working groups to address cybersecurity risks associated with the current curtailment system. At a high-level, the current discussion contemplates the installation of a redundant TDSO server and the necessary firewall protections in place. The communication (COM) modem at the local facility will establish an encrypted secure socket layer (SSL) connection with the utility server and must be initiated by the PCS; no third party of the TDSO can initiate the connection with the TDSO server.

Although Japan has thought out the curtailment scheme, implementation at the residential scale is not ubiquitous. There are questions whether this control architecture is scalable particularly in high DER environments because it would require the TDSO to control and operate each individual DER. As discussed later in this section, Japan is keen to move towards an aggregator model, where not only will coordination be simplified by only having to communicate with aggregators instead of multiple end-devices, but the aggregators may also provide grid services in the hopes of minimizing curtailment of renewable resources, while ensuring system stability.

Drivers for Change

The Great Earthquake of March 2011 revealed shortcomings in the traditional vertically integrated utility, regional monopoly model: the lack of a mechanism to transmit electricity beyond the local region, little electricity competition, and limitations to handle the changing energy landscape. Following 2011, Japan sought to reform the electricity market with the intent of securing stable energy supply, to reduce electricity prices, expand business opportunities, and increase customer choice. The new electricity market is meant to facilitate the 2030 energy goals, which include the reintroduction of 20-22% nuclear generation, and 22-24% of renewable energy supply.[80] Solar PV is expected to increase to 64 GW (an increase from 36.7 GW in October 2016), and wind is expected to increase threefold to 10 GW.[81]

A few of the initiatives that have spurred the need for change, and to achieve the government's desired market changes and renewable goals include: zero net energy home (ZEH), zero net energy building (ZEB), and virtual power plants. Japan set targets of achieving net zero energy consumption in residential houses in half of newly constructed homes by 2020 and average net zero energy consumption in newly constructed homes by 2030. In the commercial sector, the targets include: net zero energy in newly constructed public buildings by 2020 and average net zero energy in newly constructed public and private buildings by 2030. Finally, Japan made the strategic move to invest in virtual power plant (VPP) research as a way to aggregate resources (i.e., ZEB, ZEH, FIT, DR, etc.) as a means for better coordination to provide essential grid services. This investment began in 2016 and currently averages $30M USD per year.

Future System Architecture

Japan's market reform is centred on the idea of opening up a distribution market and improving the coordination of DER. As indicated in the roadmap in Figure 35, Japan is on track to unbundle the transmission and distribution business from the traditional vertically integrated model. When the TDO is legally separated for the rest of the traditional utility functions in 2020, Japan will also move to abolish the retail tariff. By 2020, Japan also plans to establish a real-time market to facilitate the participation of DER to provide wholesale grid services to the transmission networks. The TSO has identified capacity services to maintain operating reserves as a near-term need and the first service to be offered to the real-time market. Typically, each region in mainland Japan will maintain an 8% reserve margin to ensure a stable supply of capacity. The island of Okinawa, which has no interconnection to mainland Japan, maintains operating reserves equivalent to the largest generating unit. Future services could include frequency regulation and response services as renewable energy increases; local services are not contemplated at this time.

[80] "Japan's Energy White Paper 2017." Ministry of Economy, Trade, and Industry (2017), *Japan's Energy White Paper 2017*, available online: http://www.meti.go.jp/english/report/downloadfiles/energy_hakusho_201711.pdf. P. 4

[81] K. Ogimoto (2017), Kazuhiko, *Introduction: What and why are TSO/DSO Issues?* Proceedings of the CEE 29th Symposium Energy System Integration. November 17, 2017. P. 3

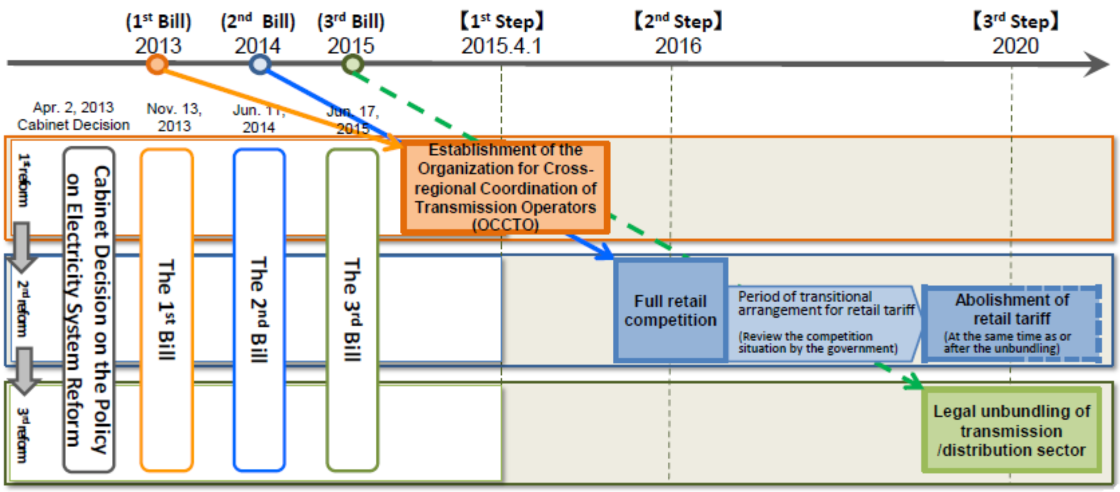

Figure 35: Japan's electricity market reform roadmap. Source: METI

The future DER coordination architecture has not been decided but is currently the topic of intense discussions in Japan. As shown in Figure 36, below, the discussions to date are headed in the direction of a federated TSO/DSO (TDSO) model. This is unique to Japan in that the TO also retains the TSO function and is combined with the DO into a single entity that is responsible for its balancing area. As such, in this model the combined TDSOs would have the overall balancing responsibility for the region. Japan is also considering creating an aggregator coordinator.[82] The aggregator coordinator would be responsible for coordinating the dispatch of resource aggregators and VPPs, who in turn controls the various distributed resources and end devices through energy management systems. The aggregator coordinator will directly communicate with the TDSO with bi-directional information flow between the two entities. The power retail providers may serve as a resource aggregator of their customer's supply-side and demand-side resources, in addition to their normal functions of securing sufficient supply to meet customer demand and providing daily supply-demand forecasts to the TDSO. Today, power retailers will leverage customer resources to balance their supply and demand as a way to avoid penalties imposed on them from the TDSO having to procure or supply capacity should the retail provider fail to procure sufficient capacity to meet their demand. As the regional balancing authority, the TDSO will assume responsibility for curtailable merchant and residential generation.

[82] Ministry of Economy, Trade, and Industry (2018), "*Looking at next generation electricity network beyond 2030*," Energy Resource Office, Ministry of Economy, Trade, and Industry, March 22, 2018. P.12.

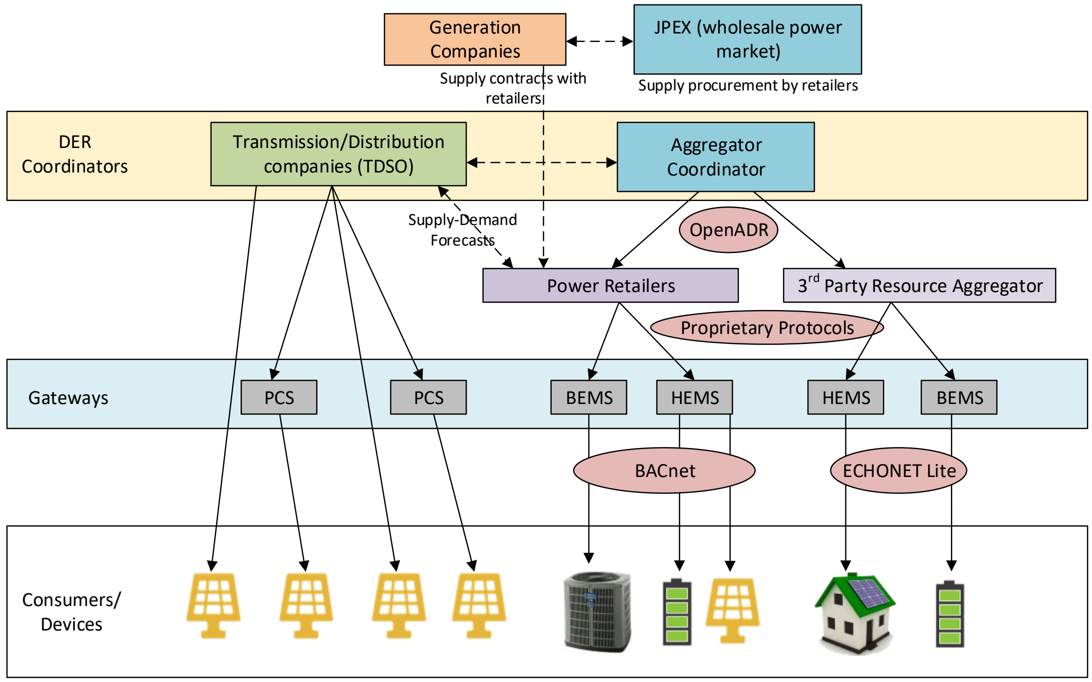

Figure 36: Japan's contemplated future grid architecture with DER.

Japan has also focused on developing communication protocols and output control of DER over the past several years. For the home energy management system and building energy management system needed to accomplish zero net home (ZEH) and zero net energy building (ZEB) targets, Japan developed a communication protocol between the energy management system and the home end-devices, called ECHONET Lite[83] and plans to use the protocol BACnet[84] for buildings. Between the resource aggregators and the TDSO, Japan plans to utilize OpenADR 2.0b[85]; however, the protocol must be modified to better accommodate the coordination of DER. For example, OpenADR was not originally developed for supply-side devices, and may not have the functionality like active power set points, tracking power quality measurements, among others. Between the aggregator and the building energy management system (BEMS) or home energy management system (HEMS), the designated protocol is still open for discussion. Currently, OpenADR and Modbus[86] based SunSpec[87] protocol for inverters are under test to fill this gap in the DER coordination architecture.[88]

Japan is confident, from previous experience, that demand response resources can respond within three hours for certain services; however, Japan views virtual power plants (VPP) as needing the same

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[83] Refer to: https://echonet.jp/english/

[84] Refer to: http://www.bacnet.org/ Refer

[85] Refer to http://www.openadr.org/index.php?option=com_content&view=article&id=84:openadr-alliance-releases-2-0b-profile-specification&catid=21:press-releases&Itemid=121

[86] Refer to: http://www.bb-elec.com/Learning-Center/All-White-Papers/Modbus/The-Answer-to-the-14-Most-Frequently-Asked-Modbus.aspx

[87] Refer to: https://sunspec.org/

[88] H. Ishii (2017), Hideo Ph.D., *System Architecture & OpenADR Applicability in the Japanese Integrated Grid,* OpenADR DER Tutorial and Workshop, April 18-19, 2017. P. 33.

characteristics as conventional generators. Therefore, pilots are currently being conducted to test whether some of those traditional grid services, such as, 5- and 15-minute frequency regulation and capacity (for the rare extreme peak demand days) be replaced by a VPP, in addition to cybersecurity protections.[89]

Japan views battery energy storage as a key component of a VPP. With the stated desire for VPPs to provide the equivalent service as a generator, the resource aggregators must combine distributed resources (e.g., solar PV, storage, electric vehicles, demand resources, and co-generation). Energy storage, however, would enhance a VPP's ability to avoid generation imbalances, avoid curtailment, and increase its reliability. Japan has not yet assessed the true value of battery energy storage. Japan currently offers subsidies that aim to reduce the "payback" period of battery investments that take advantage of the flexibility of the technology to provide multiple services.

Primary Reference Documents

Ministry of Economy, Trade, and Industry (2017), *Japan's Energy White Paper 2017*

http://www.meti.go.jp/english/report/downloadfiles/energy_hakusho_201711.pdf. P. 4

This whitepaper discusses Japan's energy landscape and key policy measures. Japan has adopted the following three strategies: 1) strengthen energy security; 2) implement energy conservation and renewable energy policies that consider environmental concerns alongside growth; and 3) balance public interest issues, such as stable supplies of energy and reduced costs, with market liberalization and growing competition. This paper provides an overview of market reforms.

K. Ogimoto (2017), *Introduction: What and why are TSO/DSO Issues?* Proceedings of the CEE 29th Symposium Energy System Integration

Translated from Japanese in Document Library as "171117_CEE29th_Introduction-What ares the TSO-DSO issues.pdf"

This slide presentation document provides a snapshot of the proposed 2030 energy mix in Japan, describes the history of the Feed-In Tariff (FIT) for PV, and provides descriptive visuals of the PV output curtailment process.

Solar Association, Japan Electronics Association, and Electric System Alliance (2015), *Using PCS with Output Curtailment System*

In Document Library as "Output_Curtailment_System – English.pdf"

This document goes into detail on the PV curtailment methodology. It includes several diagrams the describe roles and responsibilities as it relates to curtailment.

[89] Ministry of Economy, Trade, and Industry (2018), "*Looking at next generation electricity network beyond 2030*," Energy Resource Office.

4.6 PJM Market

Current System Architecture

PJM's current system architecture is comparable to that of the other US ISOs/RTOs. See Figure 37.

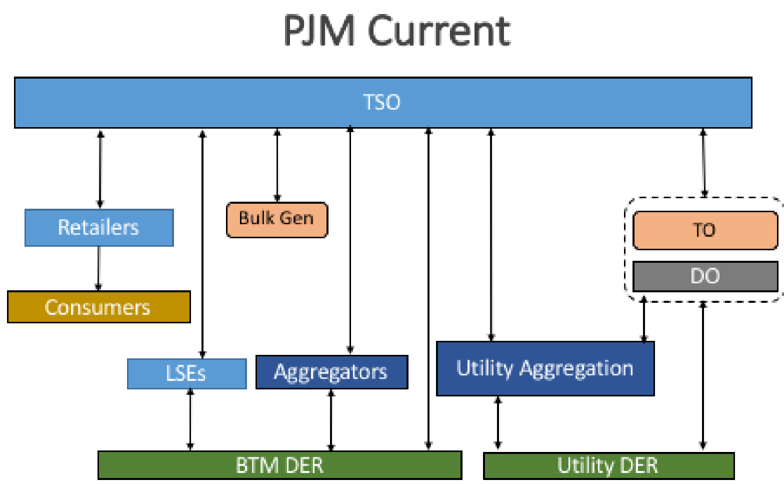

Figure 37: Current coordination framework for PJM Market

PJM has the roles of TSO, market operator, and balancing authority, but does not own any transmission assets; the transmission assets are owned by member TOs who are responsible to maintain and physically operate the assets in accordance with PJM's direction. PJM's balancing authority area covers all or parts of 13 states and the District of Columbia, and thus contains numerous transmission and distribution utilities – TDOs that both own and operate transmission and distribution systems – that are subject to the regulatory bodies of their states or, in some cases, municipalities. PJM's market structure includes real-time balancing via a locational marginal pricing (LMP) and a central capacity market, the Reliability Pricing Model (RPM), which procures capacity three years forward to ensure supply adequacy. The central capacity market is a feature of PJM that is found in some of the other US ISOs/RTOs. Most of the TDO service areas in the 13 states are restructured in that the utilities do not own generation, and there have been competitive retail energy providers for over 20 years.

PJM has extensive experience with demand response (DR) participating in its markets, including the RPM capacity auction. Much of the DER participating today in the PJM market participates as DR, for which PJM uses the term "DR DER."[90] Total DR DER in 2017 was 1,499 MWs. These are mainly not renewable DER; 99% of the 1425 capacity market DR DER are powered by diesel or natural gas.

At the same time, there has been an increase in the amount of BTM energy storage and controllable loads providing regulation in PJM. Behind the meter battery storage provided 74% of the DR in the

[90] PJM (2017), *Distributed Energy Resources (DER) that participate in PJM Markets as Demand Response,* available online: http://pjm.com/-/media/markets-ops/demand-response/2017-der-annual-report.ashx?la=en

regulation market in 2017. This is fairly consistent with the amount in 2016. Electric water heaters provided 26% of the DR in the regulation market in 2017, displacing BTM generators providing DR regulation from 15% share in 2015 to 1% in 2017.

The upshot of the above is that most DER participating in PJM markets today participate under the DR construct with direct operational control of PJM in a Total TSO model. More complicated cases including multi-use applications of DER and aggregation of smaller DER to form virtual resources are in the early stage of stakeholder discussion at PJM.

Drivers for Change

As with the other US ISOs/RTOs, there are renewable portfolio standards (RPS) in many of the PJM states that are driving development of utility-scale renewable generation, and end-use customers are adopting DER at varying rates in the different states. (At this time PJM has about 2,500 MW of BTM solar PV installed in its area.) As a result, PJM must consider operational practices and market provisions at transmission/wholesale level, as well as the need to consider how to enable more diverse DER types to participate in the wholesale market.

PJM has two initiatives underway to prepare for a higher volume of renewable generation and DER in the future. First is the Demand Response Strategy published in June 2017, which specifies short-, medium- and long-term goals for DR, which will tighten performance requirements for DR providing ancillary services while shifting energy-market DR toward increasing demand elasticity.[91]

Second, PJM has created a Distributed Energy Resources Subcommittee[92] within its stakeholder structure to: "investigate and resolve issues and procedures associated with markets, operations, and planning related to distributed energy resources in accordance with existing or new PJM process protocols. For the purposes of this subcommittee, a Distributed Energy Resource (DER) is defined as any generation or electric energy storage resource connected to the distribution system and/or behind a load meter." One of the subcommittee's explicit responsibilities is to: "Develop new coordination practices, protocols, and/or other information sharing techniques between PJM, transmission owners, electric distribution companies, municipal utilities, cooperatives, and DER providers regarding the safe and reliable operation of DER with respect to both the Bulk Electric System and the distribution system." Important to keep in mind that this subcommittee does not represent the interests of all stakeholders or the 13 state regulatory commissions, several of which have different perspectives on the role of PJM regarding DER and their retail markets.

Future System Architecture

PJM and the related TDOs have not yet formally engaged in a discussion or development on an architecture for the high-DER future. However, the work of the new PJM DER subcommittee offers a

[91] PJM (2017), *Demand Response Strategy,* available online: http://www.pjm.com/~/media/library/reports-notices/demand-response/20170628-pjm-demand-response-strategy.ashx

[92] Refer to: http://www.pjm.com/committees-and-groups/subcommittees/ders.aspx

fairly detailed initial straw proposal for DER and DER aggregator (DERA) participation in the PJM markets.[93] In its January 2018 educational session for the DER subcommittee PJM introduced the concept of wholesale DER (W-DER) as a new type of market participant that can sell capacity, energy and ancillary services to PJM, building on the existing generator and DR participation models. The proposed W-DER model allows for DER aggregations to meet the 100kW minimum size threshold as well as individual DER; an aggregator must be at least 100 kW and no greater than 1 MW capacity and can contain no more than one individual "anchor" DER greater than 100 kW.

The strawman proposal also includes provisions for coordination with the relevant distribution utility (Electric Distribution Company or EDC). An aggregator cannot span multiple EDCs. The proposal says that each individual DER within an aggregator's portfolio must go through either the EDC's state- or FERC-jurisdictional interconnection process. In addition, if the aggregator contains multiple DER on the same or adjacent distribution feeders the aggregator must obtain confirmation from the EDC that there are no reliability impacts from the coordinated activity of the DER.

Regarding operational coordination with the EDC the proposal specifies sharing of PJM's DER day-ahead schedules with the EDC, sharing of telemetry, and provision to the EDC of basic details on all W-DER in the EDC's territory, but provides no further details on these items.

Meetings of the DER subcommittee thus far during 2018 have focused on measurement and settlement procedures for DER participating in the PJM market, as well as PJM's observability of "non-wholesale" DER for both operations and planning purposes.[94] As such, although there is no explicit consideration of grid architecture or TSO-DSO coordination models thus far, PJM's approach is fully consistent with a Hybrid DSO approach. PJM does not appear to be exploring modelling of distribution systems in its software, yet it recognizes that some degree of coordination with the EDC is necessary but does not seem to be considering a more instrumental role for the EDC with regard to DER coordination. Rather, the focus is entirely on DER either participating in the wholesale market to be dispatched by PJM or comprising the "non-wholesale" DER segment for which PJM needs observability. For the latter, PJM's recent strawman proposal places responsibility with each TO to gather this information from the EDCs in its area and provide it to PJM.[95]

Primary Reference Documents

PJM DER Subcommittee home page

> http://www.pjm.com/committees-and-groups/subcommittees/ders.aspx
>
> This page provides complete agendas and meeting presentations for PJM's DER subcommittee, which is PJM's venue for introducing straw proposals for stakeholder discussion. To date the main substance has consisted of new participation models for DER and DER aggregations, some examples of measurement and

[93] PJM (2018), *Distributed Energy Resources Subcommittee: Education Session*, available online: http://www.pjm.com/-/media/committees-groups/subcommittees/ders/20180126-special/20180126-ders-education-pjm-proposal.ashx

[94] Complete agendas and meeting materials for PJM's DER subcommittee are available at the subcommittee web page: http://www.pjm.com/committees-and-groups/subcommittees/ders.aspx

[95] Refer to: http://www.pjm.com/-/media/committees-groups/subcommittees/ders/20180425/20180425-item-03-non-wholesale-der-observability.ashx

settlement for these models, and provision to PJM of visibility data on non-wholesale DER for operations and planning.

Distributed Energy Resources (DER) that participate in PJM Markets as Demand Response, January 2017

http://pjm.com/-/media/markets-ops/demand-response/2017-der-annual-report.ashx?la=en

This document provides details on the quantities, participation modes and wholesale services provided by DER under the DR construct.

Demand Response Strategy, June 28, 2017

http://www.pjm.com/~/media/library/reports-notices/demand-response/20170628-pjm-demand-response-strategy.ashx

This document lays out PJM's short-, medium- and long-term objectives and strategies for transitioning DR, mainly to increase performance and measurement requirements for DR to provide ancillary services, while shifting DR that only provide energy toward contributing to demand elasticity rather than wholesale participation.

5 Conclusion

The international review of DER coordination architectures has found that future DER coordination architectures are at an early stage of development with the UK, EU CA and NY efforts at the forefront. Also, outside of the UK and Japan, the current future architecture proposals do not represent multi-stakeholder consensus on how the DER coordination architecture may develop.

Figure 38 displays a continuum of DER wholesale market participation and distribution network services in relation to the maturity of the development of TSO-DSO coordination architecture and places each of the locations reviewed for this report on it. As can be seen from the diagram's upper right quadrant, none of the locations are at the stage of detailed implementation, most are in the early development stage. Every international location reviewed has many outstanding questions which have not been resolved or considered as yet, including a rigorous system architectural evaluation.

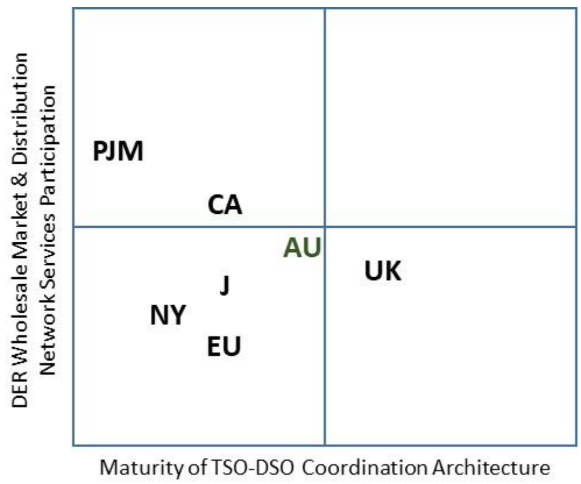

Figure 38: DER Coordination Architecture Maturity and Market & Network Services Participation

In this context, the international review has identified:

- UK has the most comprehensive evaluation of various DER coordination architectures underway, including a planned benefit-cost analysis later in 2018. The UK process for developing and evaluating TSO-DSO coordination is the leading practice worldwide.
- California, New York, and PJM all have extensive DER participation in wholesale markets. California and New York TDOs are using DER aggregators for distribution network services spurring near term changes to address immediate TSO-DSO coordination with DER aggregators. Given the scale of distributed solar and battery storage in California there are implementation insights worthy of consideration. However, there are no multi-stakeholder effort yet to address longer-term architectural structures.
- The EU TSO and DO associations have recently developed respective white papers on proposed DER coordination architectures that are currently under discussion. However, there is limited use of DER in wholesale markets and/or for distribution network services in the EU at this time and therefore, the papers and discussions are more forward looking.

- Japan is undergoing the final step to restructure its electric industry with the opening of retail completion, growth of solar PV and battery storage system, and creation of a national TSO over the past few years. These changes include current early stage discussions to develop a DER coordination architecture.

However, as indicated in Figure 38, Australia is furthest along when considering both DER market participation experience and development of a future architecture including the efforts of AEMO and the ENA-CSIRO Electricity Networks Transformation program. This doesn't mean that international insights cannot be gained, but instead potential collaborations should be established that are beneficial for both parties. For the reasons summarized above, the Newport Consortium recommends for further consideration: the UK Energy Network Association's Open Networks effort, the European Union efforts, and the DER market participation implementation developments in California.

The key findings from Newport Consortium's investigation for AEMO consideration include:

- There is general acknowledgement of the need for distribution-transmission coordination, rather than purely transmission level coordination, due to existing or anticipated scale of DER integration and utilization in wholesale markets and/or for distribution network services, and potential for uncoordinated operational impacts at either distribution or transmission.
- There is growing international recognition of the role of system architecture in the design considerations for DER participation in wholesale and/or distributed markets. Of particular focus is on addressing issues such as observability, tier bypassing and hidden coupling along with the potential to address these issues through layered decomposition.
- None of the leading international efforts have progressed to detailed design or implementation of DER coordination architectures including dispatch optimization.
- The specific roles and responsibilities of a DSO are still being evaluated as is the question of whether the distribution network operator/owner should be a DSO. The issues under discussion and trade-offs are discussed at length by De Martini and Kristov (2015).[96]
- In the near-term, leading overseas jurisdictions are responding to distribution level constraints via connection standards limiting exports, or market rules limiting aggregation to nodes, i.e. distribution connection points, where connection policies ensure constraints will not arise.
- Markets are considering both maximum and minimum thresholds for DER aggregation. Maximum size for a single aggregator is considered as potential mitigation to address market power and/or non-performance beyond the existing prudential requirements to participate in the wholesale market or provision of distribution network services. Also, several markets have been lowering the minimum DER participation level for wholesale markets, which is trending towards 100 kW to increase the number of DER that may participate directly (100kW or greater) or through aggregations of at least 100kW.

[96] P. De Martini and L. Kristov (2015)

Based on the Newport Consortium's key findings, it has reached the following conclusions of relevance to Australia's DER coordination efforts:

- Development of a workable DER coordination solution will require a significant industry work stream and resourcing, which will ideally be sponsored by policymakers and the regulator
- DER coordination will need to involve distributor network operators as key actors in both operational information and control architectures irrespective of whether they become DSOs. From a wholesale market perspective, this could be analogous to the TSO-TO roles and responsibilities in several international locations.
- Aside from wholesale markets participation considerations, there is an issue of what role the DO plays regarding distribution network services.
- If any future architecture involves a DSO type role and set of responsibilities, as currently envisioned internationally, the question arises as to whether an independent DSO is needed. This is an unresolved issue under active discussion in the UK, Europe, and the United States (nationally).
- Development efforts involve multi-year efforts to design and implement, based on benchmarks from the U.K., California, and New York.
- Key elements for a best practice DER coordination architecture include:
    - Developing clear objectives and identifying required capabilities
    - Development of a DER coordination architecture including identifying and defining the roles and responsibilities for TSO, DO, and DER aggregators
    - Wholesale – distribution network services markets coordination, and operational information and control architectures
    - DER connection, registration, and measurement requirements and communication protocols
    - Coordinated demonstrations to test and verify implementation of architectural elements above and address industry knowledge gaps
    - Cost-effectiveness assessments to evaluate the net benefit of various options for customers, society, or other specific objective/s

Appendices

Appendix A: Additional International Insights

Hawaii

Hawaiian Electric Companies serve the populated islands of the U.S. State of Hawaii, except for Kauai which is served by a community-owned utility. Both Hawaiian Electric and the Kauai electric cooperative are vertically integrated utilities regulated by the Hawaii Public Utility Commission. So, while there are no structural challenges regarding TSO-DSO coordination, there are aspects worth highlighting with regards to the coordination of DER in a high renewables system. For context, Hawaii has over 26% renewables in its system and the largest percentage of distributed solar PV in the US at approximately 15% of all customers. Also, each of the islands are electrically isolated therefore there is no power interchange among these systems.

Additionally, new distributed solar PV has the option to sell energy to the utility under various tariffs or through an aggregator's program. Hawaiian Electric is required to buy services from DER aggregators for both resource adequacy and grid services for ancillary services, such as capacity and fast frequency response, as well as non-wires alternatives for transmission and distribution upgrades. This obligation creates significant operational challenges on each island given the rapid growth of both distributed solar PV and large-scale wind and solar resources plus the greater reliance on DER to manage the power system.

Hawaii, like California, is challenged by a "duck curve" as shown for Maui in Figure A - 1**Error! Reference source not found.** below. This phenomenon is not isolated to Maui as each of the islands are facing similar challenges, especially O'ahu which is the most populated and has the highest rooftop solar PV adoption.

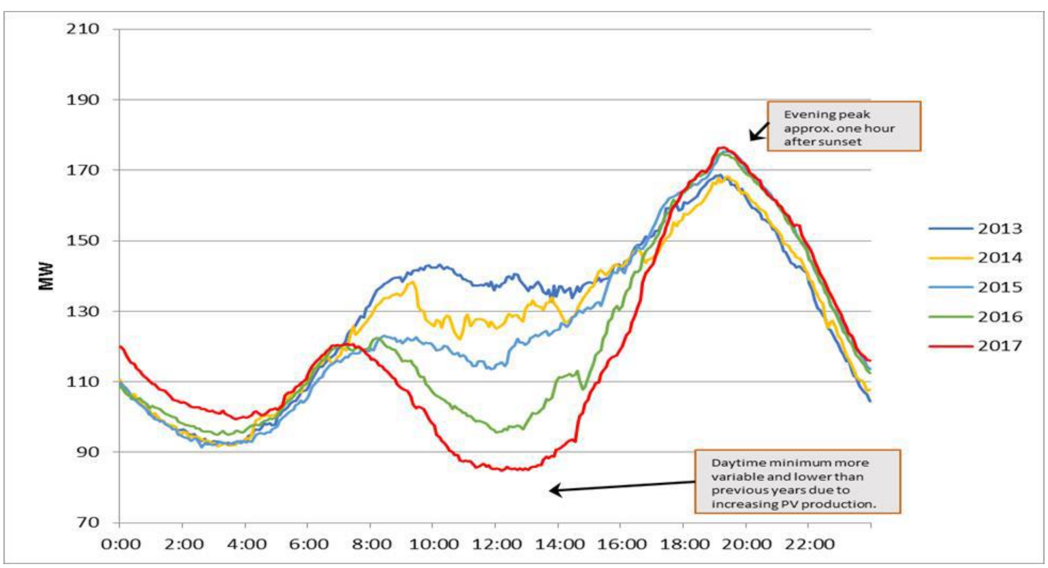

Figure A - 1: Maui Duck Curve

As can be seen in the figure above, the load curve has been drastically reshaped creating lower minimum loads, excess daytime energy, and steeper afternoon ramps that require significantly more system flexibility. It also leaves the power system more vulnerable to weather impacts. The loss of traditional rotating mass generation reduces the system inertia and needs to be addressed. Two operational aspects to highlight are: system security and DER feed-in-management.

System Security in Hawaii

In Hawaii,[97] analysing the reliability and security of the grid is critical to the integration of significant quantities of variable renewable energy. System security (or operating reliability) is defined by the North American Electric Reliability Corporation (NERC) as the ability of the system to withstand sudden disturbances.[98] These disturbances or contingencies can be the loss of generation or electrical faults that can cause sudden changes to frequency, voltage, and current. Operating equilibrium following these disturbances must be restored to prevent damage to utility and end-use equipment and to ensure public safety. Stability of a power system can be characterized by frequency stability, voltage stability, and rotor angle stability.

Transmission planning criteria in conjunction with TPL-001[99] establishes the design parameters and analysis requirements necessary to plan, operate, and maintain the transmission system.

One of the key factors that impacts system security in Hawaii is the reduction of must-run generation to increase the amount of variable renewable generation on the grid required to achieve 100% renewable energy. The various resource plans to reach that goal must be analysed to ensure frequency stability, voltage stability, and rotor angle stability are maintained from an overall system perspective.

FREQUENCY STABILITY: Dynamic simulations of the largest loss of generation contingency are performed to determine frequency stability of a resource plan. The analysis determines system requirements for frequency response reserves; fast frequency response one and two (FFR1[100] and FFR2[101]), and primary frequency response (PFR[102]). Currently, system inertia is determined by the unit commitment and dispatch schedule from the production simulation data, but future resource plans may require technologies like flywheels to maintain a minimum rate-of-change of frequency.

To evaluate resource plans, a PSS/E screening tool is used to analyse hourly production simulation data from PLEXOS. The screening tool is a condensed single-bus network model that facilitates an automated process to perform dynamic loss of generation simulations for every hour in selected years. The screening tool calculates the frequency nadir for the largest generator trip, and each hour is placed in a

[97] The Hawaiian Electric Companies own and operate the grids on the islands of Hawaii, Maui, Oahu, Lanai and Molokai.

[98] NERC, Definition of "Adequate Level of Reliability," December 2007, available online: http://www.nerc.com/docs/pc/Definition-of-ALRapproved-at-Dec-07-OC-PC-mtgs.pdf.

[99] HECO (2016), *Hawaiian Electric Companies' Power Supply Improvement Plans* (PSIP), P. O-599, available online: https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_companies_PSIP_update_report_4_of_4.pdf

[100] Fast frequency reserves 1 will reduce the rate of change of frequency w/ response proportional to the generation contingency. FFR1 is triggered via a signal from a generator trip or df/dt. See, PSIP, P. O-15.

[101] Fast frequency reserves 2 will reduce the rate of change of frequency with response that is independent of generation contingency. This category of FFR is tailored to distributed resources with autonomous control. FFR2 is triggered at 59.7 Hz. See, PSIP, P. O-15.

[102] Primary frequency reserves stabilize frequency in either direction w/response proportional to changes in speed or frequency.

frequency nadir bin for further analysis. Two informative hours (a boundary hour and typical hour) are selected for further detailed analysis on the full transmission system model to determine frequency response reserve requirements. The loss of generation contingency in the boundary hour is a dispatch that results in the lowest frequency nadir with a lower probability of occurrence. The dispatch for the typical hour represents a contingency event with a higher nadir and a higher probability of occurrence.

Besides calculating the frequency nadir, the screening tool performs the following production simulation data analysis:

- Calculates FFR1 requirement for each hour in the study year
- Calculates total MVA (megavolt-ampere) of online synchronous generation to meet minimum fault current requirements for relay protection
- Calculates PFR from spinning reserves

Resource plans must meet reliability standards specified in TPL-001. For the island of Oahu, the largest loss of generation contingency shall result in no load shedding while the criterion for Maui and Hawaii Island is 15% of system load.

An area of concern and study for a system with high penetrations of DG-PV is its limited under voltage ride-through capability. An electrical fault can cause large capacities of DG-PV into momentary cessation operation or under voltage trip. Either case could represent a very large loss of generation contingency.

VOLTAGE STABILITY: To determine steady state voltage stability, QV analysis is performed to determine reactive power requirements under applicable N-1 or N-2 transmission line contingencies. The QV analysis ensures bus voltages remain within specified limits for different unit commitment and dispatch schedules, typically under high load conditions.

The system's reactive power requirements can be met with capacitor banks, static VAR compensators, dynamic VAR compensators, and synchronous machines. Of these alternatives, only synchronous machines can provide short circuit current for proper relay operation and transient voltage stability, so only synchronous condensers are analysed to meet reactive power requirements to prevent potential stranded investments of the other alternatives.

In addition to steady state stability, transient voltage stability analysis is analysed as part of the system security evaluation. The Hawaiian Electric Companies are in the process of developing PSCAD models to perform transient voltage stability analysis to determine weighted short circuit ratio[103] (WSCR) requirements. The WSCR is defined as:

$$WSCR = \frac{\sum_i^N SCMVA_i * P_{RMW_i}}{\left(\sum_i^N P_{RMW_i}\right)^2}$$

[103] Y. Zhang. S.H.F. Huang, J. Schmall, J. Conto, J. Billo and E. Rehman (2014), "Evaluating system strength for large scale wind plant integration," IEEE PES General Meeting, National Harbor, MD, pp. 1-5.

In this formula, SCMVAi is the short circuit capacity at bus *i* from synchronous generators; P_{RMWi} is the MW output of nonsynchronous generation at bus *i*; and N is the number of wind plants interacting with each other and *i* is the wind plant index. Based on this formula, more synchronous condensers will be required as renewable portfolio standards (RPS) requirements increase. This is why reactive power requirements are being addressed with synchronous condensers as opposed to capacitor banks, static VAR compensators, or dynamic VAR compensators.

ROTOR ANGLE STABILITY: Rotor angle stability and transient voltage stability are closely linked. A system with transient voltage stability issues typically will experience rotor angle stability issues as well. This is a by-product of weak electrical systems. The most severe disturbance is an electrical fault at a generating station bus. If a close-in fault is not cleared within the critical clearing time of a generator, loss of synchronism can occur. Analysis performed for rotor angle stability include breaker failure analysis for Oahu and delayed clearing faults for Maui and Hawaii Island.

The output from the system security analyses results in an identification of resource and grid needs that may be met by traditional utility solutions. However, the Hawaiian Electric Companies will look to non-traditional solutions to meet system security needs, such as aggregated DER or DR programs to deliver services to meet bulk power system security requirements. However, as noted in California,[104] for DER to successfully provide grid services, they must meet the same technical and operating standards as the rest of the system such that when DERs are interconnected, they do not impact the safety and reliability of the grid. In addition, DER that provide services must also operate in a manner that aligns with the local transmission and distribution area's electrical loading attributes to ensure safe and reliable distribution service.

DER Feed-in-Management in Hawaii

Feed-in-management of DER is a critical to a cohesive and secure grid, when a significant portion of the generation will be sourced for renewables, specifically, wind and solar. Even more critical is the ability to manage DER output when, in aggregate, DER is significantly the largest single generator on the grid, as is the case on each major island in Hawaii, where each island is electrically isolated with no interconnections.

[104] Ibid.

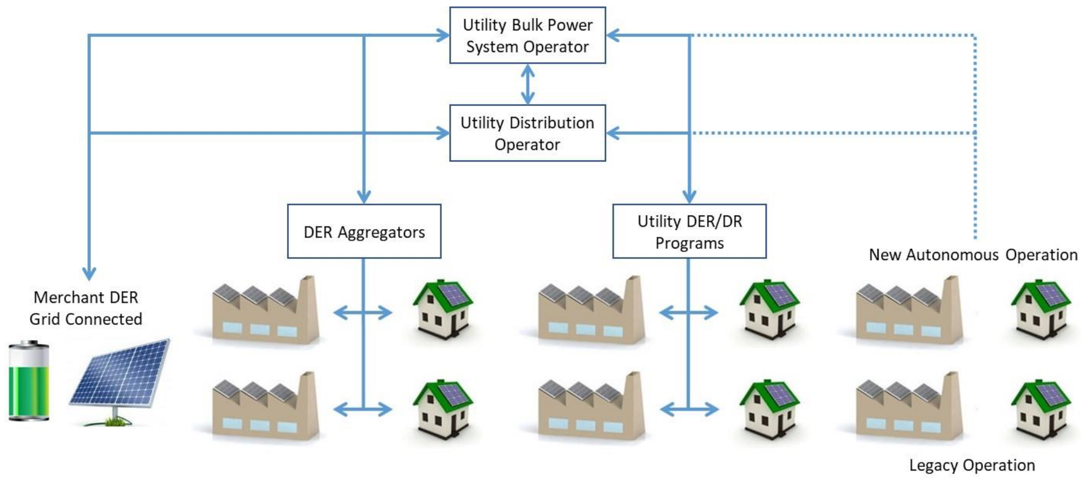

Figure A - 2: Distributed, Layered Approach for DER

As illustrated in Figure A - 2, the level of operational control and interfaces involve several different types of DER and controls within a distributed, layered architecture:

- **Merchant DER** (Independent Power Producers): Third-party provider assets directly connected to sub-transmission or distribution systems providing services directly to the grid that require direct control and an information interface with grid operations. This is necessary given the anticipated size of merchant resources.
- **DER Aggregators:** Aggregation of customer assets to provide services to the grid. For aggregated DER, the Hawaiian Electric Companies do not believe it is necessary to directly control each resource. Rather, the Hawaiian Electric Companies expect to establish and secure an operational interface with each aggregator to share operational instructions and appropriate information.
- **Utility DER/DR Programs**: Where customers participate in the utility programs. For those programs that the utilities manage, direct interface with and control of those devices may be needed.
- **New Autonomous Operation**: Post-2016 customers with "advanced inverter" DER who choose not to participate in an aggregator or utility program. Establishing operational standards for DER, such as those being developed in IEEE 1547[105] and as the Hawaiian Electric Companies received approval for in 2018. The Hawaii Public Utilities Commission in the DER Investigative Proceeding, Docket No. 2014-0192, approved Hawaiian Electric Companies proposal to require mandatory activation of certain critical autonomous functionality of DER advanced inverters. One of the critical mandatory functions that will aide in alleviating bulk system frequency impacts is Frequency-Watt.[106] A challenge for the industry is that IEEE 1547 leaves quite a lot of flexibility for manufactures to select different communications and protocols; achieving functional standardization will be difficult.

[105] Institute of Electrical and Electronics Engineers (IEEE) *1547 Standard for Interconnecting Distributed Resources With Electric Power Systems*, available online: http://grouper.ieee.org/groups/scc21/1547/1547_index.html

[106] Hoke, Andy (2017), *The Frequency-Watt Function Simulation and Testing for the Hawaiian Electric Companies.* Grid Modernization Laboratory Consortium, US Department of Energy, available online: https://www.nrel.gov/docs/fy17osti/68884.pdf

- **Legacy Operation**: Pre-2016 inverter DER without advanced inverter functionality capabilities such as the expanded frequency and voltage range ride-through. Legacy DER systems will not be directly managed but may require additional investment, especially at the bulk system level, to account for their impacts as more DER is integrated onto the grid.

Abnormal System Reliability Controls

In addition to the normal operational controls described above, there needs to be alternative means of controlling the amount of power being produced by DER systems under abnormal circumstances that threaten grid reliability and stability. One of the current challenges in accommodating DER at the system level is that the amount of active power being produced is not visible to or controllable by the grid operator. In the event of an excess generation event at the bulk system level or other conditions that threaten the security of the grid, other resources must be adjusted. Central generators have physical operating range limitations, which restrict the system's flexibility beyond a certain limit.

As DER continues to grow, the need for visibility and controllability of DER resources is becoming increasingly critical to maintain grid reliability and stability.[107] This is particularly important under abnormal conditions where, for example, generation and load are mismatched, available controllable generation is at its minimum output, and all dispatchable grid-scale renewable resources are curtailed and offline. Under such conditions, if supply and demand cannot be balanced quickly, system frequency could deviate from normal operating ranges. Although not expected to occur often with a balanced portfolio in the Power System Implementation Plan (PSIP) with corresponding integration systems (storage, DR, etc.), this abnormal circumstance could result in an island-wide blackout exacerbated by the loss of legacy DER with inverters that trip out of service due to system frequency or voltage excursions during these events. This is a situation somewhat unique to island grids like Hawaii's. A grid operator in California, for example, is able to export any excess energy to neighbouring states during periods of surplus energy on the system and import shortfalls from other western states.[108]

To address this need for system security, stability, and reliability, the following functionality is required of DER resources (such as inverter-based PV):

- Secure, reliable, low latency, bi-directional communication path between utility operations and control devices, including the ability to enable event/control signals, device status, and data transmission.
- Ability to temporarily curtail power production for operational emergency events, including:
  - Both power produced by DER and load participating in grid services.
  - Discrete load curtailment for under-frequency events when continued power production from DER is required to maintain system stability.
- Revenue-quality power-production measurements.

[107] Essential Reliability Services Working Group (2017), *Distributed Energy Resources Report,* NERC, available online: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

[108] See Western Energy Imbalance Market online: https://www.westerneim.com/Pages/About/default.aspx

This type of information and controllability is consistent with requirements for large-scale generators and NERC findings for distributed resources.

The Companies have explored and will continue to explore, test, and pilot several technology solutions to enable this functionality for DER resources. This includes advanced meters with variable latching relays, utilization of the advanced meter to address an advanced inverter, "meter collars" as a modification to the traditional meter socket for a DER system, and a smart household circuit breaker that provides metering, monitoring, and control of the interconnected DER. Another option coming to market through the adoption of IEEE 1547 advanced inverter functions is the ability to remotely control the level of inverter output. This is a promising development but is expected to take into the next decade to implement into inverter product designs and deploy in customers' systems. Notwithstanding the associated complications with establishing secure, reliable communications links to customer's devices via third-party service providers.

The Hawaiian Electric Companies expect that this two-part control architecture – utilizing primary control methods to manage normal operations and backup controls for abnormal conditions to maintain system reliability – will be the most cost-effective for customers and aggregators. However, the Hawaiian Electric Companies must retain an option to directly control DER devices (for normal operation) if the market fails to satisfy the necessary reliability and security requirements.

Primary Reference Documents

Hawaiian Electric Company, (2017) *Modernizing Hawai'i's Grid For Our Customers*

https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/final_august_2017_grid_modernization_strategy.pdf

This grid modernization strategy document describes the scope, purpose, and estimated cost of the work required to update the Hawaiian Electric Companies' energy network, and how it will help the state achieve a renewable portfolio standard of 48% by 2020 and ultimately 100% by 2045.

Hawaiian Electric Company, (2018) Planning Hawai'i's Grid For Future Generations: Integrated Grid Planning Report.

https://www.hawaiianelectric.com/Documents/about_us/our_commitment/20180301_IGP_final_report.pdf

This document proposes an integrated grid planning ("IGP") approach innovates on the methods and tools of the prior power supply improvement plan ("PSIP"). This planning process intends to yield the most cost-effective renewable energy pathways that are rooted in customer and stakeholder input and aims to achieve expanded market opportunities for resource, grid services, and non-wires alternatives for transmission and distribution.

New Zealand

The New Zealand energy system has seen strong demand for electricity on the back of strong growth in population and economic development. New Zealand's power system supply has developed around its abundant hydro and geothermal resources, which have helped to keep wholesale costs low, except during periods of drought, which are infrequent. New Zealand has a competitive wholesale market and retail market as well as partially regulated transmission and distribution sectors.[109] Prices in the wholesale market are set on a nodal basis at transmission-distribution interfaces.

Transpower is the Transmission System Operator (TSO) and market operator, responsible for matching current bids and offers in the real-time wholesale market and setting market clearing prices on a nodal basis. All generators >10 MW must participate in the wholesale spot market. The market operator also operates the ancillary services market for operating reserves, frequency control, voltage support, and blackstart.

There are 29 local distribution companies who operate as natural monopolies and are regulated by the Commerce Commission.

DER Background

Approximately 50 MW of solar PV generation has been installed to date, most of which is rooftop solar. This uptake is despite the absence of any direct incentives or Feed-in-Tariffs (FITs). The electric vehicle market has grown in the last 2-3 years, largely driven by imports of second-hand EVs from Japan. There are approximately 6,000 EVs in New Zealand at the moment.

Although Demand Response (DR) must be at least 10 MW to participate in the market, the TSO, Transpower, is currently piloting a DR program[110] through 2020 with a view to implementing a demand response mechanism for aggregating smaller DR resources. Although Transpower prefers participants with >20kW peak demand, any size or number of sites can participate.

Current System Architecture

The current NZ system architecture relevant to DER is shown in Figure A - 3. The TSO is the only DER aggregator at the moment at the wholesale market level, as connections must be greater than 10 MW to be registered in the market. Distribution companies are able to aggregate DER for network services, and able to bid into the TSO managed DR aggregation function. Individual DR providers are able to bid directly into the TSO DR market as well, rather than via the distribution company.

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[109] Some distribution businesses are self-regulating.

[110] See Transpower: https://www.transpower.co.nz/keeping-you-connected/demand-response/faq#Why%20DR

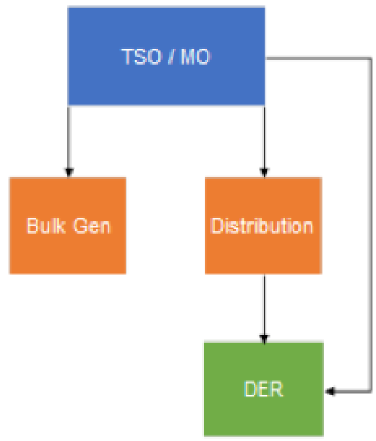

Figure A - 3: New Zealand System Architecture Relevant to DER

Drivers for Change

New Zealand's electricity regulatory bodies and market participants have begun to discuss ways to incorporate and encourage mass market participation of DER. Consequently, the coordination of DER has been a key focal point of discussions, especially since mass market participation by consumers will likely impact the current structure.

The national regulator, the Electricity Authority (EA), has begun focusing its efforts on addressing barriers to DER entering energy markets in New Zealand. As part of their 2017 market report, the EA consulted with stakeholders, including the TSO, DOs, and market participants regarding suggested changes to the EA's work program to ensure consumers benefit from technological changes and innovation.

The consensus is that market mechanisms to promote appropriate valuation of energy services are inadequate, and competition within, and the protection of entry into, the market is not sufficient. Some of the stakeholder's comments call for more efficient distribution pricing mechanisms and exchange markets for contestable supply of network services.

Following on from its stakeholder engagement process, the EA has also set up the following strategic priorities, work streams and advisory groups as part of its transformation program (see Figure A - 4).[111]

[111] J. Rampton (2018) *Regulatory implications of distributed energy resources in Australia & NZ seminar*, Electricity Authority, available online: http://www.mbie.govt.nz/info-services/sectors-industries/energy/electricity-market/nz-smart-grid-forum/lectures-workshops-panel-discussions/publications/5-ea-john-rampton-regulatory-implications-of-der-in-australia-and-nz.pdf

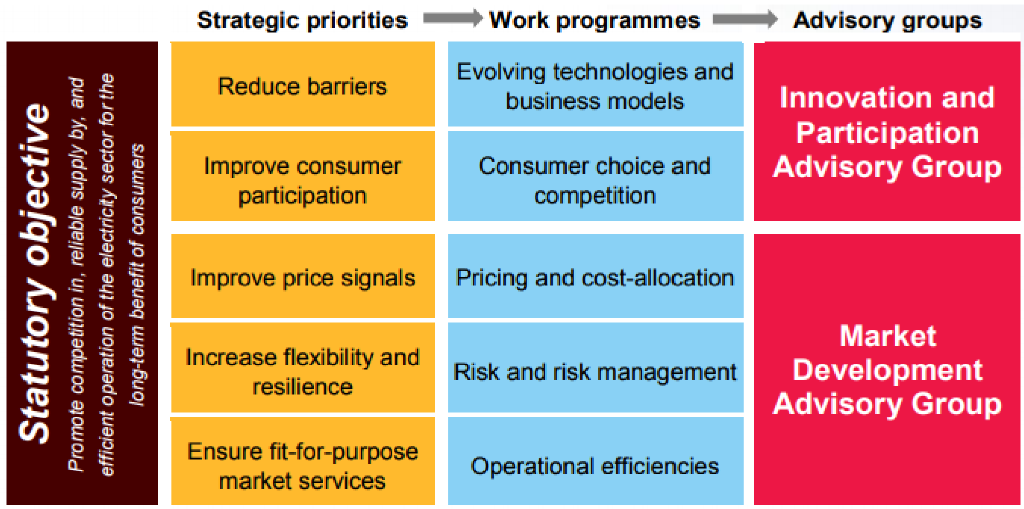

Figure A - 4: The Electricity Authority's Advisory Groups and Roles

Addressing shortcomings and inefficiency in the market ultimately falls to the advisory groups created by the EA to consider how the market should develop and innovate to accommodate the future of the energy industry. Some of their key premises are that they are technology-agnostic, they want to facilitate innovation and information flows, and they want technologies and business models to compete, ideally in the most efficient way possible.

Future System Architecture

Discussions for the future of DER coordination are in the very early stages and consequently the future state architecture is relatively undefined.

Nevertheless, some visions for the future are being put forward by stakeholders to the EA work program, including that of the Independent Electricity Generation Association, whose vision is displayed in Figure A - 5. The diagram presents an arrangement whereby consumer hosted DER is coordinated by the distribution network, who also coordinates distribution connected resources, some of which bid into the market, where it is coordinated by the market operator.

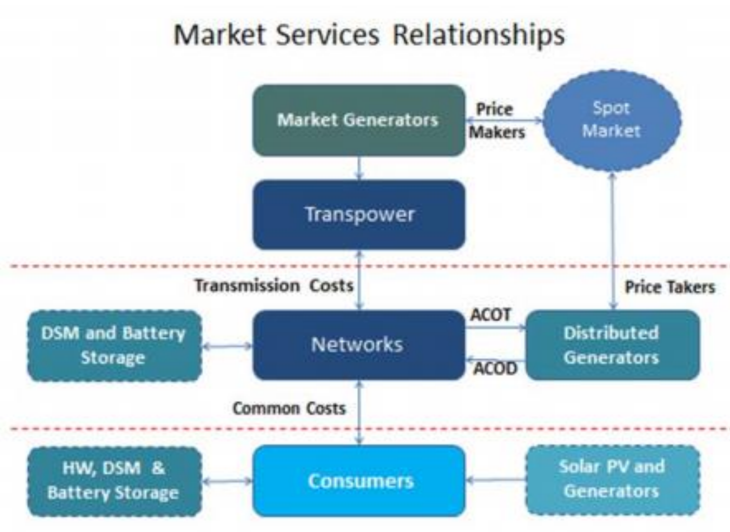

Figure A - 5: Market Services Relationships[112]

The above approach implies shared DER coordination between the ISO/TSO and the DSO. However, it is important to emphasise that this concept is not the official view of the EA or the industry generally.

Although, in Australia the Australian Energy Market Commission (AEMC) has already dismissed Multiple Trading Relationships (MTRs) in their 2016 Determination, the EA's MTR work stream is actively considering the pros and cons of allowing this in the New Zealand market[113] (see Figure A - 6).

[112] IEGA (2016), Summary of Submissions on DGPP Proposals, available online: https://static1.squarespace.com/static/5727d8c4e707eb1dbd493d8d/t/5803e9eed482e94444455756/1476651503836/IEGA+summary+of+submissions+Oct+2016.pdf

[113] Electricity Authority (2017), *Multiple Trading Relationships Consultation Paper,* available online: https://www.ea.govt.nz/dmsdocument/22859

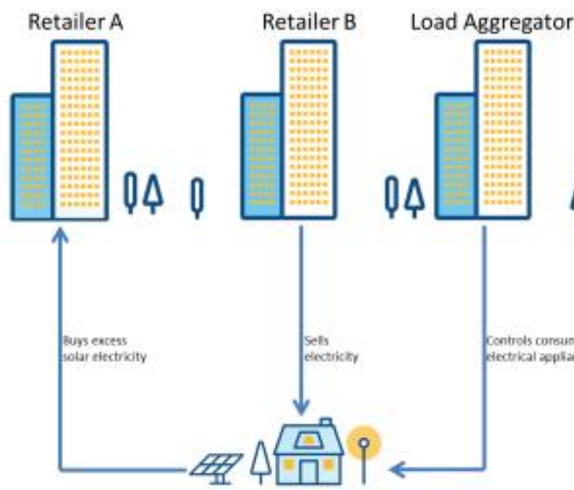

Figure A - 6: Consumer Multi-Trading Relationship[114]

The EA's approach to MTRs is highlighted in this paper because of the additional complexities it raises for DER coordination, namely by creating n-possible DER agents for a given connection point. The work stream is ongoing, and it is not yet known whether this concept will make it into the final future state architecture design for New Zealand.

Finally, the market operator also initiated its DER integration investigations in 2017 with a report[115] focused on the value of distributed energy storage and the current barriers to efficient market adoption. In addition to developing high level estimates of storage benefits at the system level, the report identified a number of key questions to be addressed as part of future work streams. Architecture related questions include:

- What is the role of aggregators in the DER value chain?
- Is there a need for a market-based mechanism to facilitate participation?
- What commercial structures, market design and systems will be required to realise benefits for battery owners, and how will a widely diluted consumer base participate and be paid?
- How will offer and dispatch priorities be managed, "double dipping" be prevented, and the implications of non-delivery and performance shortfalls be managed?
- Is central coordination and/or aggregation required, will emerging Peer to Peer (P2P) technology have an impact?
- What technical and performance standards and rules are required for domestic, large edge of network/ customer or grid scale systems to ensure integrity of the system?

Perhaps unsurprisingly, these are many of the same questions under consideration in the locations reviewed in this report.

[114] A. Mordoh (2018), EA, Equal access project: Assessing the presentation - existing arrangements and their effectiveness and impact of the current equal access arrangements, Electricity Authority, available online: Commerce Commission regulation, available online: https://www.ea.govt.nz/dmsdocument/23093

[115] Transpower (2017), *Battery Storage in New Zealand Discussion Document*.

Texas

Texas is effectively an electrical island – that is there are no large transmission interties with neighboring states. This creates Texas' need for self-sufficiency, similar to Hawaii. However, Texas has an all of-the-above strategy for energy independence that leverages its abundant natural gas resources as well as nuclear, coal and renewable generation. The Electric Reliability Council of Texas (ERCOT) is the TSO for the state and has total generation capacity of about 71,000 Megawatts (MW), reserve margin 14.6% and a resource portfolio dominated by natural gas power plants – about 72% installed capacity. Texas has the most competitive-based electricity structure for wholesale and retail energy in the US. Competitive energy market pricing drives the economics and mix of resources developed and dispatched. Low price in-state natural gas resources have driven the generation mix.

DER growth in Texas is relatively low as there are no state incentives for DER or net energy metering tariffs. In 2017, Texas had under 1,000 MW of distributed generation (e.g., large fossil fuel-fired reciprocating back-up units to small rooftop solar systems) in a system that peaks at about 60,000 MW. As a result, ERCOT has stated that "based on installed capacity and current rates of growth, these resources do not pose an immediate or near-term reliability concern for the transmission grid."[116]

DER Background

Excess commercial and residential rooftop solar PV energy is paid ERCOT clearing prices by default. In practice, customers enter into wrap-around commodity buy-sell agreements to sell excess to a competitive retailer and purchase supplemental energy to make up the difference between the solar output and their gross load. Figure A - 7 below illustrates the very low adoption of solar. For contrast, California's annual solar installations are currently 100 times greater than Texas. Storage is also slowly making inroads to arbitrage the price differences. But, with energy prices relatively low DER growth will not likely reach California levels until well into the next decade. As such, the development of more advanced DSO functions will not be needed until after 2020 or beyond.

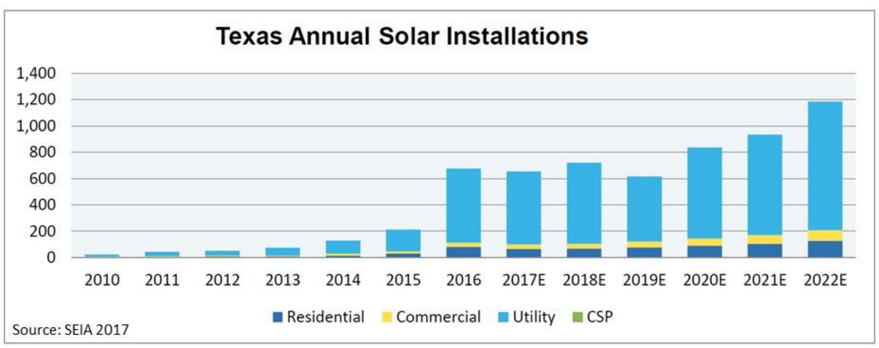

Figure A - 7: Texas Annual Solar Installations (MW)

However, in the aftermath of several devastating hurricanes over the past decade, Texas passed legislation to require onsite back-up generation at critical facilities which spurred growth in customer

[116] ERCOT (2017), *DER Reliability Impacts and Recommended Changes V. 1.0*, available online: http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL_032217.pdf

diesel and natural gas fired generators. The growth has been strong in large commercial and industrial sites as customers and retailers leverage these units to mitigate retail delivery demand charges and leverage to sell emergency demand response services to ERCOT. The overall number is still relatively low, but the concern is growing about the lack of visibility and control of these units which are typically sized at just under the 10MW threshold for wholesale market participation and related telemetry and control requirements.

However, ERCOT and DO recognize the several drivers will lead to great DER adoption including "customer desire for independence, environmental consciousness, and declining costs of DER acquisition." Additionally, ERCOT, sees DER growth also being driven by opportunities to participate in Emergency Response Service (ERS), demand-charge avoidance in the form of Four Coincident Peak (4CP) response, and Load Zone-level wholesale price response in the Real-Time Energy Market. The state has also taken steps to encourage storage resources to participate in the wholesale market by providing the same interconnection and transmission access rights as generators in ERCOT. These factors have spurred discussions in the state regarding the planning and operation of a more dynamic and distributed system.[117,118] There have been discussions regarding the role that DER may provide as a provider of distribution grid services.[119]

DER Market Participation

ERCOT allows for DERs to earn revenue by participating in the "front-of-the-meter" ERCOT wholesale market:

> **Load Resource (LR)**: Available to >100 kW, albeit suited to loads that can afford and manage the ERCOT registrations by themselves. These loads can participate as an independent market participant and are often quite large (many MWs).
>
> **Aggregated Load Resource (ALR)**: A market participant type created in 2014, ALR allows a mix of different residential and commercial loads to be aggregated and registered as a single resource, primarily for demand response into the real-time energy market and non-spin.[120]

The several DER market opportunities and related qualifications are summarized in Figure A - 8 below.

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[117] ERCOT (2016), *Distributed Resource Energy and Ancillaries Market Task Force*, available online: http://www.ercot.com/committees/board/tac/dreamtf

[118] ERCOT (2017), *DER Reliability Impacts and Recommended Changes V. 1.0*

[119] Brattle (2014), *The Value of Distributed Electricity Storage in Texas,* Oncor

[120] Rocky Mountain Institute (2015), *Electricity Market Reform: Why Texas could be Next,* available online: http://blog.rmi.org/blog_2015_05_14_electricity_market_reform_why_texas_could_next.

Type	Qualifications	Energy	Ancillaries	Aggregations
Distributed Generation	Less than or equal to 10 MW, connected at less than 60 kV	Load Zone payment for injection	N/A	No
Distributed Renewable Generation	Less than or equal to 2 MW, renewable, installed on customer's side of a meter	Load Zone payment for injection	N/A	No
Non-Registered DG	< = 1 MW	Load Zone payment for injection	N/A	No
Distributed Renewable Generation (DRG) below registration threshold	Addressed in Protocol Section 11.4.4.2, Load Reduction for excess Photovoltaic and Wind Distributed Renewable Generation	Load Zone payment for injection	N/A	No
Non-DRG below registration threshold	Addressed in Protocol Section 11.4.4.3, Load Reduction for excess from Other Distributed Generation	Load Zone payment for injection	N/A	No
Emergency Response Service (ERS)	An emergency service consistent with P.U.C. Subst. R. 25.507, Electric Reliability Council of Texas (ERCOT), Emergency Response Service (ERS), used during an Energy Emergency Alert (EEA) to assist in maintaining or restoring ERCOT system frequency. ERS is not an Ancillary Service.	Capacity Payment for contracted hours	N/A	Yes
Emergency Response Service Generator	Either (1) an individual generator contracted to provide ERS which is *not a Generation Resource* or a source of intermittent renewable generation and which provides ERS by injecting energy to the ERCOT system, or (2) an aggregation of such generators	Capacity Payment for contracted hours	N/A	Yes
DG within a Non-Opt In Entity (NOIE) area	If the DG is within a NOIE's boundary, the DG Resource owner will need to coordinate with the NOIE regarding possible data requirements to properly report the impact of the DG generation on the NOIE's exchange onto the ERCOT system.	Negotiated with NOIE	N/A	No
Aggregated Load Resource	Distributed resources within a load zone may aggregate to provide energy and/or ancillary services.	Ancillary Service Payments, bid-to-buy / avoided cost for deployment in response to price	Yes	Yes
DG acting as a Resource	Less than or equal to 10 MW, connected at less than 60 kV. LRS is capped at zero	Load Zone payment for injection	N/A	No

Figure A - 8: ERCOT DER Market Opportunities

ERCOT settles load at zonal prices and generation at nodal market prices launched in late 2010. Under ERCOT rules, distributed generators participate "passively" in the energy market. They effectively "chase" Load Zone Settlement Point Prices (LZ SPPs) via either "controlled passive response" from fossil fuel facilities or renewable facilities combined with storage; or via "uncontrolled passive response" from renewables that produce only when the sun is shining, or the wind is blowing.

These distributed resources (mostly back-up generators) are behind the customers meter resources and are not directly controllable or visible to ERCOT. As a result, the TSO is unable to effectively utilize these resources, and the lack of information currently available regarding DER location, capacity, and real-time status will prove insufficient at some point in the future. There is a recognition that DER penetration will continue and at larger scale will create impacts on transmission reliability in a "future scenario in which a larger share of the regional generation mix may come from the distribution system." As such, ERCOT has been evaluating the potential reliability impacts of increasing DER activity.[121,122]

Electric Reliability Council of Texas (ERCOT) approved the formation of Distributed Resource Energy and Ancillaries Market Task Force (DREAM TF) in 2014 to explore the issues related to market participation, visibility and control needed to allow greater DER market participation. The DREAM TF completed its report in 2016[123], but given the lack of DER growth or perceived urgency no follow-on activity was undertaken.

Likewise, informal discussions in Texas began in 2015 among distribution operators and ERCOT regarding the implications of potential growth of DER and their aggregated participation in wholesale markets on the reliability of the distribution system. The initial direction was toward employing the Hybrid DSO model to coordinate physical system operations between ERCOT, distribution operators and DER providers to ensure safety and reliability. However, given the lack of DER adoption there was no urgent need to continue the discussions. Currently, there are no discussions underway.

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[121] ERCOT (2017), *DER Reliability Impacts and Recommended Changes V. 1.0*

[122] ERCOT (2015), C*oncept Paper on Distributed Energy Resources in the ERCOT Region*

[123] DREAM Task Force TAC Report (2016), available online: http://www.ercot.com/content/wcm/key_documents_lists/72724/TAC_Dream_Report_Draft___2016_01_22_DREAMTF.docx

Appendix B: Interview Questionnaire

The following questions formed the basis for the interviews with the primary locations. Most locations have not advanced their discussions to address all of these questions. So, several questions could not be answered.

Current System Architecture
What is the current system architecture, and what are the problems identified with this architecture for coordination of large quantities of active DER?
Highlight the current structure including brief description of the roles, controls and flows of information between the system operator, distribution and transmission network providers, retailers, aggregators and customers and any other relevant entities during the real-time dispatch process.
Drivers of Change
Beyond the obvious need for changes to operational processes to orchestrate DER in markets, highlight the unique reasons driving the architectural and design direction including the timing of the changes underway.
Future System Architecture
Describe in summary the architectural direction (and any decisions made) for DER coordination for each primary location.
Why is this model proposed?
What alternatives, if any, that were/are being considered?
How is it proposed that this system architecture should adapt to better orchestrate active DER?
Is any form of staged implementation under consideration?
What will be implemented under each stage?
What is the proposed timeline for implementation?
Structure
Is the level of complexity (related to a TSO model) perceived as manageable in a single-stage optimisation? If not, how do alternative models more effectively manage this complexity?
Is it considered more effective for the distribution business to coordinate the dispatch of DER in their network, and provide an aggregated dispatch to the system operator?
What are the kW/MW thresholds for active DER participation and aggregation?
How are different sizes treated differently? (both with respect to the size of the individual units, and the total aggregated size).
Operational Roles & Functions
Is it seen as technically feasible for the transmission-level system operator to take on the role of dispatching all DER?
For example, could the distribution business develop constraint equations representing each distribution network constraint, and provide those to the system operator for inclusion in the system-wide dispatch optimisation?
Which entities are responsible for resource, transmission and distribution planning? How is this information used to inform market and operational changes?
Who is responsible for providing forecasts of DER and load? Is this done by the distribution business, the system operator, both, or other?
Will any new independent organisations be established, such as a Distribution System Operator, Distribution Market Operator, or other? Why is it seen as necessary to establish a new independent organisation?
Will a new "distribution level market" or similar be established? Why? How will this operate in parallel or coordinate with the wholesale market?

How are markets addressing the market power and non-performance risks associated with large aggregations of participating DER?
Controls
If DER results in a binding network constraint, what arrangements are proposed to determine the allocation of network capacity to the various DER service providers? Will this be based upon bids/offers, or allocated pro rata? If pro rata, is this based upon installed capacity, operation at the time, historical performance, or other?
Are certain services from DER considered more critical (for system security, for example), and dispatched as a priority, when network constraints prevent unconstrained operation of DER?
Are there any geospatial limitations proposed on the aggregation of DER? For example, is DER aggregation limited to single transmission connection points, to allow accurate inclusion in transmission constraint equations? Will this be implemented with any kW/MW size limits?
How are hierarchies of DER services managed?
How is it ensured that large aggregations of active DER participate in such a way that they can be actively managed in the dispatch process? For example, what prevents an aggregator from operating "outside of the market" to reap the benefits of active DER (for example, by assisting with managing retail contract positions), while avoiding the potential of being constrained due to network constraints?
Have new registration categories been explored?
How are participation requirements enforced?
Are generation (feed-in to the grid) and load (consumption from the grid) treated differently in this framework? Why?
How is generation behind the meter that only supplies a customer's own load treated?
Is nodal pricing (or a similar equivalent) seen as critical? How will this be implemented at the distribution level?
How is customer equity addressed?
Are peer-to-peer transactions contemplated? If so, how does peer to peer trading operate in this system? How are security constraints managed during this process?
Information Flows
How will the flows of information between various entities and the decision-making process in real-time dispatch change?
If so (a DSO model), how would information flow between the relevant parties? How are decisions on dispatch allocated between the parties?
Benefits-Cost Analysis
Have benefits and costs analysis of DER coordination framework been performed?

Appendix C: Architectural Principles

The word "architecture" is used in many ways, including to mean a house or building layout, a master plan, or an organization model for a device like an integrated circuit chip or for the internal arrangement of a company. It may refer to block diagrams, high level ("logical") views of an information system, a system design or implementation, or some other abstraction like a layer model. Many of these uses are proper, but some (block diagram, system design or implementation, or layer model) are not.

A **system architecture** is a conceptual model of a complex system that defines the structure, behaviour, and essential limits of a system. It is the highest-level representation of a system and enables reasoning about the system's characteristics. Complex systems are composed of many related structures, just as a house multiple structures: the frame, the electrical system, the water piping and drainage system, etc. System architecture focuses on structure – how elements of the system are laid out, connected, or related. Structure sets the essential bounds on what a system can and cannot do; getting the structure right allows all the pieces to fit into place and the downstream decisions are simplified, thus helping to future-proof investments. Getting structure wrong or not adjusting legacy structure to new needs results in costly integration and poses significant risk of stranded investments and unrealized benefits.

Architecture is often confused with design but differs in significant ways. An architecture consists of three kinds of elements: black box components, structure, and externally visible characteristics (attributes). Architecture sets the "shape" of the system by specifying the smallest possible set of constraints or boundaries on the system needed to ensure proper system operation. System designers are left with considerable freedom, and in fact, a proper architecture allows for more than one possible design, whereas a design allows for only one possible implementation. Refer to Figure C-1. Architecture produces enforceable constraints such that any allowable design must fit within the architecture.

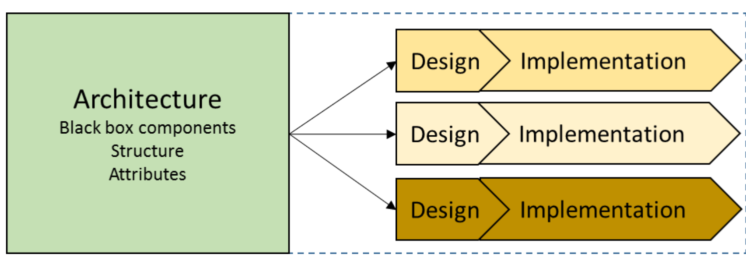

Figure C-1: Architecture and Designs

Grid Architecture is system architecture for the electric grid. More formally, Grid Architecture is the application of system architecture, network theory, and control theory to the electric power grid. An electric grid is composed of many inter-related structures, including the electric infrastructure (circuits, etc.), control structure, communications and information system structures, industry structure (including market structure), regulatory structure, and coordination framework. Note that market and regulatory structures do not refer to market or regulatory rules, but the nature of the relationships among various entities involved. **Coordination framework** refers to the structure of the coordination mechanisms involving many decentralized grid elements and entities, and may include aspects of control, dispatch, and markets. Because existing electric systems have inherited much legacy grid structure, new capabilities such as DER integration can require both understanding of existing grid structure and potential changes to grid structure.

Grid architecture differs from IT architecture in terms of focus, timing, and approach. IT architecture is focused on information systems and takes other structures as givens. Its development is usually driven in a bottom-up fashion for use cases. Grid architecture has broad and simultaneous focus on the entire set of grid structures and considers the potential need for structural changes. Grid architecture development is driven primarily top-down by systemic issues. See Figure C-2. Grid architecture development is usually an earlier stage process than IT architecture development.

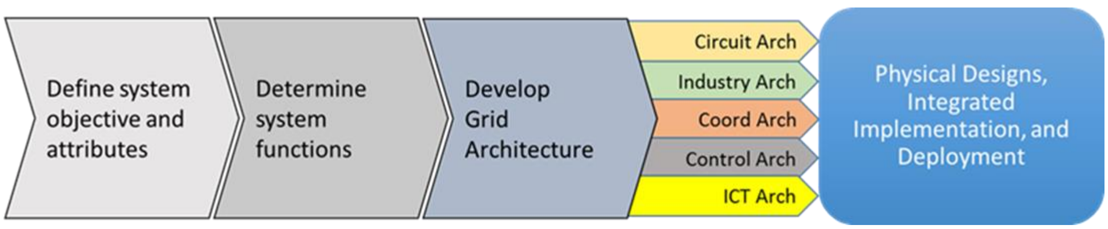

Figure C-2: Staging of Architecture Processes

Grid architecture is invaluable in working with key issues associated with DER coordination. Such issues include:

- The emerging change in grid structure caused by the bifurcation of generation into centralized, transmission-connected units and decentralized distribution-connected units
- New need for coordination of DER elements across the bulk power system and distribution network
- Impact of DER on both transmission and distribution network operations and reliability
- Control issues including existence of loops, feedback, and couplings
- Cyber vulnerability
- New roles and responsibilities for several entities and potential for tier bypassing

Layered Decomposition

In the project, we shall use an architectural framework derived from the formalism of layered decomposition to compare architectures and architecture approaches for DER coordination. **Layered decomposition** is a mathematical concept from the field of optimization theory and has been applied to distributed control[124,125] and to the analysis of grid architectures. The mathematics of layered decomposition induces a structure that is useful for grid architecture purposes. Layered decomposition solves large scale optimization problems by decomposing the problem multiple times into sub-problems

[124] Robert E. Larson, A Survey of Distributed Control Techniques, Tutorial: Distributed Control, Chapter 5, pp. 217-261, IEEE Catalogue No. EHO 153-7, 197.

[125] JD Taft, Architectural Basis for Highly Distributed Transactive Power Grids: Frameworks, Networks, and Grid Code, PNNL, June 2016, available online: https://gridarchitecture.pnnl.gov/media/advanced/Architectural%20Basis%20for%20Highly%20Distributed%20Transactive%20Power%20Grids_final.pdf

that work in combination to solve the original problem. This structure is useful for a variety of hierarchical and distributed control and coordination problems.

For this work, we are not interested in solving mathematical problems but want to use the structure implied in the mathematics because it has useful and understood properties. Instead, we will use coordination framework derived from layered decomposition as the core tool for performing the architectural analysis.

Other analysis schemas are sometimes used for work of this type, notably Smart Grid Architecture Model (SGAM). Despite its name, SGAM is not an architecture and is not an architectural framework (generator of architectures). It was devised as a means to compare smart grid use cases and solutions in terms of coverage but lacks the means to deal with essential coordination structure and in fact the SGAM mapping schema limits analysis of multi-structure relationships.[126] The SGAM User Manual says: "The Smart Grid Architecture Model (SGAM) [SG-CG/C] is a reference model to analyse and visualise smart grid use cases in a technology-neutral manner." As such, it is not useful for comparing coordination frameworks in the scope of this engagement.

As Figure C-3 below illustrates, the layered decomposition structure is sufficiently general to map to a wide variety of grid physical, information, and control structures. Use of such a framework to study DER coordination provides a common basis for examining what might at first appear to be differing grid architectures and will enable us to identify the key characteristics of each.

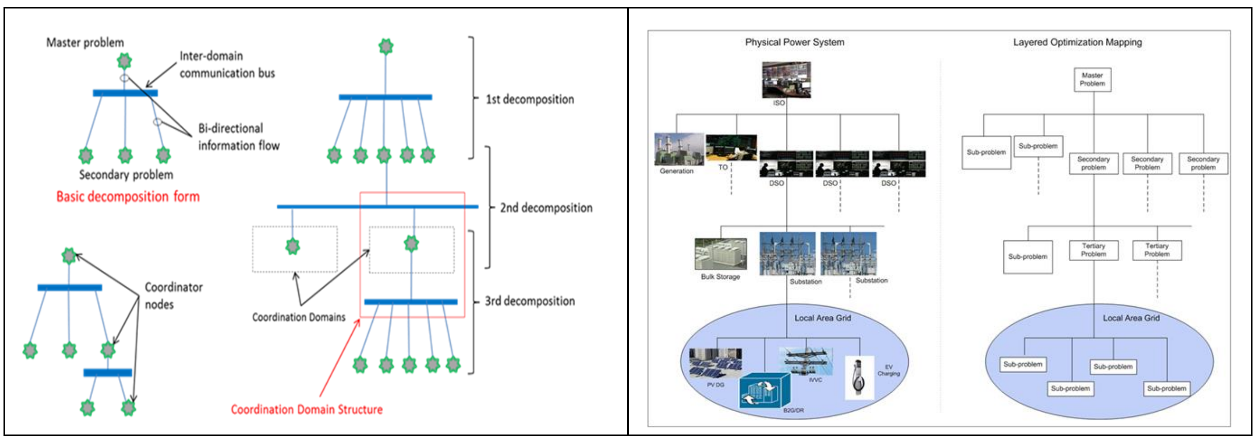

Figure C-3: Layered Decomposition and Grid Coordination Structure Mapping

The structure of the coordination framework for each architecture will be assessed in reference to the layered model to understand structural characteristics of the architectures, including tier bypassing, hidden coupling, cascading latency, scalability, and cyber vulnerability at the bulk system level due to distribution-level connectivity.

[126] For a brief analysis of 20 architectures, frameworks, and schemas, see Appendix F in Grid Architecture, available online at: https://gridarchitecture.pnnl.gov/media/white-papers/Grid%20Architecture%20%20-%20DOE%20QER.pdf

Hidden coupling and **cascading latency** are revealed in the control structure implied by the coordination framework. Viewing simplified control diagrams for grids with DER illustrates several forms of coupling, as shown in the diagrams below. Figure C-4 shows a simple control structure where the control has full observability of the grid and can determine instructions for the DER in a coordinated fashion, taking into account the effect of each on the whole system.

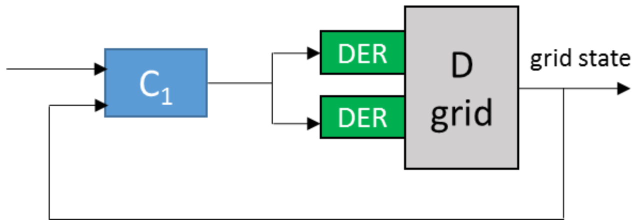

Figure C-4: Simple Fully Coordinated Control

This structure is not always feasible for various reasons but more importantly, other structures tend to evolve that have hidden problems. Figure C-5 shows a common emerging problem: two controls with partial views of grid state operating separately according to individual goals and constraints. This can be a DO and a TO, or aggregators bidding into multiple markets. They are actually coupled together via the distribution grid and can easily end up conflicting, thus causing distribution reliability issues. Even if both controllers have identical full state information, they are still coupled and can conflict if they act independently.

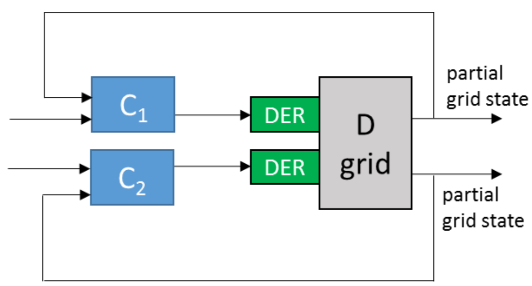

Figure C-5: Hidden Coupling via the Distribution Grid

Figure C-6 illustrates another issue: **cascading of controls**, causing not only control sub-ordinal dependence, but possible cascading latency issues since signals must pass through multiple stages that may even be separate organizations. In fact, there may be more than two cascaded controls in such arrangements, which just makes the issue larger.

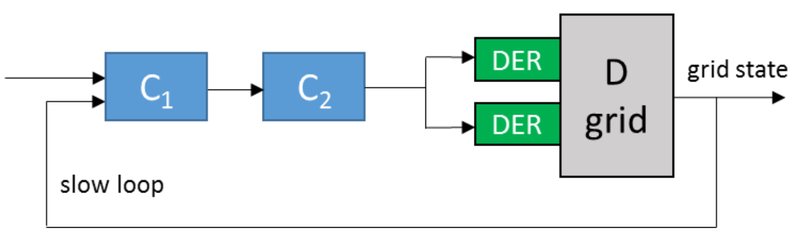

Figure C-6: Sub-ordinal Dependence and Cascading Latencies

One way to address the issues in Figure C-6 is to create a fast-inner loop involving the D grid and C_2 only. Such a loop would be a control-only loop, likely not involving a market mechanism such as C_1 may be using. This leads to the need to understand the relationships between markets and controls for grids and where each is most suitable.

Another way to address the issues of Figure C-6 is to create a hierarchical structure, such as shown in Figure C-7.

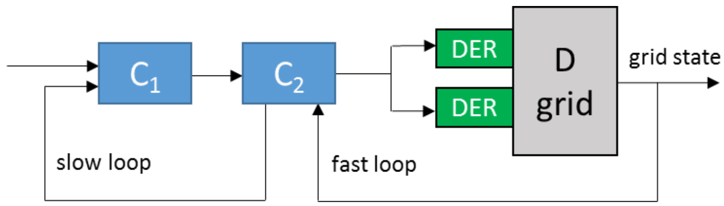

Figure C-7: Hierarchical Control Structure

In this structure, the fast and slow time cycles can be accommodated in a form that is consonant with the layered decomposition approach to coordination structure. This form has good scalability for the case where C_1 is a system operator and there are many D grids, with many C_2-level controllers.

Other control structures are possible, and many hybrid combinations can also be developed. The purpose here is to understand how coordination framework and control structure relate in terms of DER coordination.