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TSO/DSO Coordination in a Context of Distributed Energy Resource Penetration

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TSO/DSO COORDINATION IN A CONTEXT OF DISTRIBUTED ENERGY RESOURCE PENETRATION

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Abstract

With respect to electrical grids and power systems there is a trend towards a greater penetration and subsequent utilization of distributed energy resources ("DERs"). DERs can provide services to both Distribution System Operators ("DSOs")[1] and Transmission System Operators ("TSOs")[2]. Distributed energy resources are typically installed and interconnected to electricity networks that may or may not be completely controlled, monitored or analyzed by the power system operators themselves. If and when DERs are operated to provide system services and/or market actions, this may lead to system benefits and efficiency improvements, but can come with technical, economic, and jurisdictional challenges. Aggregators, DSOs, and TSOs, must be able to coordinate, monitor and dispatch resources as well as study and share information in a timely manner. Examples and recommendations for future coordination and interactions between the TSO, DSO, DER owners, and aggregators are presented and examined, in operation and market-based contexts, relevant to European and US electricity networks.

Keywords: Distribution system operator, utility, transmission system operator, distributed energy resources, wholesale markets, distribution-level markets, transmission-distribution coordination functions, electricity services.

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[1] Distribution System Operators and Utilities

[2] TSOs and Independent System Operators or Regional Transmission Operators

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1 INTRODUCTION

Distributed Energy Resources typically are defined as technologies that can be installed “behind the meter” on consumer premises connected to on-site loads or remote premises without on-site load. DERs are typically interconnected on distribution and lower voltage networks, and are smaller in installed capacity; ranging in the order of a few kilowatts ("kW") to a few megawatts ("MW") in rated nameplate capacity. A multitude of governments, transmission system or regional operators, public utility commissions and regulators, utility companies or distribution system operators, workshops, think tanks, research laboratories, and research communities will define DERs slightly differently, that include a diversity of energy resource types, capacity, and where on the power system the resources are interconnected.

Recent technological advances and cost declines in distributed energy resources and information and communication technologies ("ICT") as well as specific regional and state policies, mandates, and incentives, regulatory paradigms, and consumer trends have been major driving forces behind the increasing penetration of DERs. DERs can and do provide many services to the electric grid, and this trend will only increase as the ubiquity and ability to control these assets, for instance through management systems and smart inverters, continues to increase. However, current market designs and operational practices do not provide a level playing field for DERs to deliver services. Existing markets need to evolve, new markets need to be created, and new roles and coordination functions need to be established between distribution and transmission system operators.

This paper is structured as an exploration into the services that DERs can provide, market structures observed in the European Union and United States, the interaction between distribution and transmission system operators, the new roles that DSOs would need to perform to unlock the most value from DERs, and certain market barriers for DERs at the transmission level. Coordinating and co-optimizing distributed, typically low-voltage assets, across jurisdictions and levels of the power system are still quite nascent. Future roles of Utilities and distribution system operators, new planning and interconnection methodologies, and new wholesale market designs for DERs have been researched in theory, but not yet extensively adopted in industry. This paper highlights and advocates for not only a level-playing field for DERs where their services can be valued in markets, but also for managing the complexities associated with communication, coordination, and interactions between grid operators to coordinate the services provided by DERs.

1.1 The global reach of distributed energy resources

Distributed generation technologies, and their impacts on operations and markets, have been researched previously, but only now have they reached significant levels of penetration in the European Union (EU) and popularity in the United States (US). The penetration of distributed energy resources into markets through the provision of electricity services has important consequences for different stakeholders: consumers, system operators, energy service providers and technology companies, market traders, power equipment manufacturers, and regulators. From a market perspective, new business models are emerging related to DERs. Certain regulatory agencies are incentivizing and requiring network operators to take a more active role in the operation of their systems and to utilize innovative solutions related to distributed energy resource adoption and integration (Eurelectric, 2013; IDE4L, 2014). For grid operations, transitioning from passive to active distribution network management systems require education and training for the workforce as well as technology upgrades in communication, hardware and software. With DERs, consumers are becoming more active participants on the electric grid, helping to provide system services, which may lead to a more efficient and flexible power system.

Different actions and initiatives are currently under development globally to efficiently integrate DERs into the power system and to reform the roles of the agents involved in the transformation. The European Commission (EC) and the New York State Department of Public Service in Reforming the Energy Vision (REV) are two examples of institutions actively pursuing increased coordination between the DSOs or Utilities and the TSOs or Independent System Operators (ISOs), respectively. Both the European Commission and the REV proceedings are actively pursuing considerations for new electricity market designs (European Commission, 2015; New York State Department of Public Service, 2015). ENTSO-E (European Network of Transmission System Operators for electricity), ISGAN (International Smart Grid Action Networks), CIRED (International Conference on Electricity Distribution), EDSOs (European Distribution System Operators), CIGRÉ (International Council on Large Electric Systems), GO15[3] have task forces and working groups investigating future roles, relationships, markets, and coordination requirements for and between the operators of the electric grid.

1.2 A phased approach framework for distributed resource penetration

The research presented in this paper focuses on the organization of the interactions between TSOs and DSOs within a time frame within about 10 years. In this time frame, two situations are likely to unfold. An initial phase where current markets and practices of DSOs and TSOs continue to exist, there is low penetration of distributed energy resource and low deployment of advance metering infrastructure (AMI[4]). In this initial phase, DERs can provide services that have, in the past, dominantly been provided

[3] GO15 Reliable and Sustainable Power Grids. http://www.go15.org/

[4] Advanced metering infrastructure is commonly used or being assessed in industry. It is possible that future technologies or techniques that can provide the same or similar services will be used with greater ubiquity (i.e. monitoring and control of solar PV, smart inverter, battery, and/or load assets by an aggregator can help inform the utility of the assets)

by centralized resources. In this initial phase, DERs provide services mainly to Transmission System Operators through the applicable market mechanisms or are operated in a limited fashion by DSOs. DERs may access the Wholesale or Transmission level markets through demand response programs typically operated by an aggregator[5]. In a subsequent phase, a higher integration of DERs and AMI are expected and DERs will be able to provide new services be compensated by the applicable market mechanism. The developments of both phases are contingent upon many system specific factors and, in particular, total amount of distributed resources connected to the networks, market designs, regulatory frameworks and vicissitudes. A high-level visual representation of the main interactions between DERs and system operators are shown in Fig. 1.

In the initial phase, the net power flows are mainly unidirectional from transmission networks to end-users; DERs would provide services to the TSO and the TSO would send operational signals to DERs. Distribution System Operators have limited or nonexistent interactions with the TSO or DERs, in regards to utilization of DERs for system services. Typical services provided by DERs or Aggregators are load or demand reducing. In the subsequent phase, power flows can be bidirectional; DERs can provide services to TSO and DSO and both the TSO and DSO send operational signals to DERs. In addition, operational signals may be coordinated between both operators. In this phase, DERs would be able to provide a wider range of services to the different levels of the power system, so long as the appropriate market designs are in place and the operators have some level of visibility and/or control.

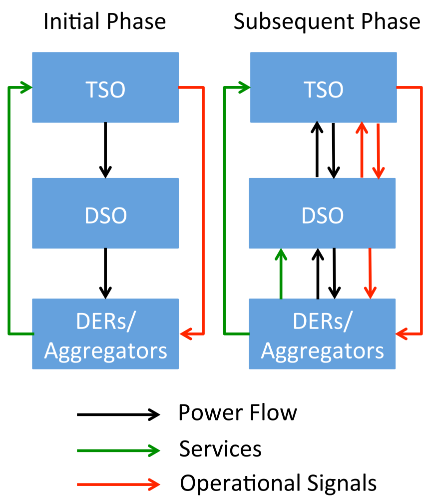

Fig. 1: Simplified diagram of the main interactions between TSO, DSO and DERs

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[5] Wholesale power markets exist in the EU and the US with many different constructs and designs. Essentially, these markets exist at the bulk or transmission or high-voltage level of the power system. These markets traditionally have been the platform where the supply from large centralized power generation facilities is matched with the electric demand, typically from load serving entities such as utilities. In the US, the transmission system operator is generally also the wholesale market operator

In the initial phase, DERs can provide services to the TSO in established markets without violating constraints within the distribution networks. In this initial phase, the margin or buffer built within distribution networks would be enough to manage flows and DSOs may not need to buy services from DERs (this phase is similar to most of the current practices where DSOs use only "wire solutions" to solve network constraints). The initial phase mentioned in Fig. 1 is a generalization because there are some networks where there is DSO-level communication with DERs, but the DERs may not be participants in those markets. In this initial phase, there are challenges with respect to the effectiveness of DERs providing TSO services and the need to extend price signals further into distribution networks to guarantee a level playing field between centralized and distributed resources. Creating a level-playing field for distributed and centralized resources is a complex undertaking involving extensive and perhaps lengthy stakeholder processes, but there are regions such as in New York, Massachusetts, Hawaii, California, Spain, and the UK that are advancing well into this new paradigm by being open to the utilization of DERs for system services; however, the paradigm shifts are far from complete in many of the developed power systems (Newcomb, 2013).

In a subsequent phase, and in some jurisdictions this is already occurring, DSOs or utilities will buy services from DERs, such as in non-wires alternatives (NWA). Non-wires alternatives are programs in which alternative or new proposed solutions are put through the same cost-benefit analysis, as would a traditional solution for the chance to be used to delay or defer potentially costly upgrades. Other, more active services provided on the distribution network could potentially be in conflict with TSO services. Different challenges need to be addressed prior to, and during this phase; first to establish new roles of DSOs and the mechanisms for purchasing distribution services, and second, to make those mechanisms coherent and coordinated with those managed by the TSO. The specific roles, functions and interactions between DSOs and TSOs will depend upon many factors. Research suggests that a few models could emerge where there is a different extent to the interaction and coordination between DERs, Distribution Operators, and Transmission System Operators (De Martini, 2015; Migliavacca, 2016).

1.3 Distributed energy services and market presence

DERs can provide both energy-related services as well as network-related services (Pérez-Arriaga, 2015). Electricity services are detailed in Fig. 2. Energy related services include real power, frequency regulation, and operating reserves, black start capability, and firm capacity (defined as enough capability of generation and demand to respond during operations). Frequency regulation is an energy-related

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and is required to meet a "standard market design" as defined by FERC (i.e. NYISO, CAISO, ISONE, PJM, MISO). In the EU, the transmission network operator is a separate entity from the market operator.

service that is utilized to maintain the frequency of the electrical grid within a specific bound. To maintain the frequency within the specified grid code limits, the grid operators typically send automatic communications and signals to the power generation units (i.e. automatic generation control (AGC), as it is in the US, communicates set points for maintaining frequency on a sub-ten second basis). In the US, the frequency is maintained around a nominal 60Hz and in Europe the frequency is maintained around a nominal 50Hz; to maintain these nominal frequencies the grid supply and demand must be in constantly and automatically monitored and controlled. Reserves are typically more discrete and the hierarchy of operating reserves corresponds to the timing with which generators[6] can respond to system loading conditions, or fluctuations, and can vary from milliseconds to hours (i.e. tertiary reserves respond slower than secondary which respond slower than primary). Network-related services include voltage control through reactive power support, power quality, mitigation of thermal or voltage constraints, and reduction in losses.

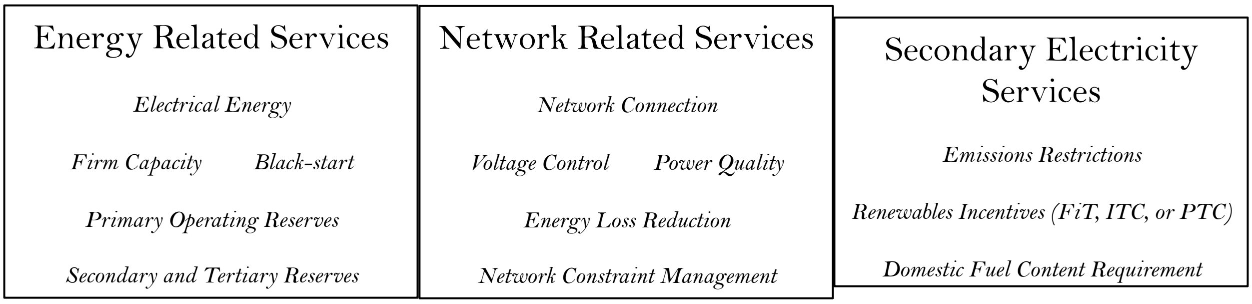

Fig. 2: Primary electricity services separated into two categories: energy and network, as well secondary services (Pérez-Arriaga et al, 2016).

Distributed energy resources can provide services to the power system at the distribution level or transmission level. For instance, a PJM pilot project found that electric vehicles could effectively provide ancillary services to the grid, such as real-time frequency regulation and spinning reserves (Kempton, 2008; Fitzgerald, 2015). These services are typically provided through an applicable market mechanism and corresponding price signal. Currently, services are most commonly priced, valued and cleared in wholesale markets. In some circumstances there are regulations or market structures that make it challenging for DERs to access wholesale markets and enable a level playing field for DERs. The transmission system and wholesale market operator may or may not be able to purchase different services from DERs, such as spinning and non-spinning reserves (or frequency reserves/response in the European Union), firm capacity, voltage support, and black-start. Future electricity systems might have very different ways to charge for different services. For instance, firm capacity could be automated with the right tariff structures, voltage control could be fixed or variable depending on the technology connected

[6] Or demand response, which is typically the curtailment of load.

on the grid, even grid interconnection, given the potential future for islanded grids, microgrids and potential for load defection, could be fixed or variable in nature, depending upon the regulatory framework (Pérez-Arriaga, 2014; Rocky Mountain Institute, 2015; Fitzgerald, 2015). Resources and technologies that are capable of providing system services should have fair and equal access to participate under appropriate market designs, and compensated for their quality of provision of the services to the grid.

In certain cases where DERs have limited participation in markets it is due in part to market rule restrictions, such as minimum resource size (capacity), shown in Table 1. In the United States, DERs are generally located on distribution grids at lower voltages (35 kV or below[7]) and they have limited access to wholesale markets due to utility imposed standards for interconnection or capacity restrictions in wholesale markets (IRC, 2014)[8]. Many of these requirements to participate in wholesale markets unfairly restrict DERs from providing system services. In European wholesale markets, these requirements are much higher and on the order of 5 to 10 MW (ENTSO-E, 2015). If the markets allow for aggregation, Aggregators may be able to leap those barriers, but in some markets they still may be restricted to participate in the provision of those services.

Table 1 Requirements to participate in US regulation markets (MacDonald et al., 2012).

	Min. Size (MW)	Aggregation Allowed	Continuous Energy Period
CAISO**	0.5	No	30 min
ERCOT	0.1	No***	NA
MISO	1	Yes	60 min
PJM	0.1	Yes*	NA
NYISO	1	No	60 min
ISO-NE	1	Yes	NA

*Requires approval.
** Forthcoming, WECC does not currently allow demand side resources to provide this product.
*** Pilots are underway to examine the ability to change this rule.

At first the PJM tariff for ancillary service provision required 5 MW for offers into the markets, but decreased over time to 100 kW; even though this decrease benefited the smaller curtailment service providers, it would occasionally still be a barrier because most providers had small portfolios when they

[7] The precise voltage specification for distribution or transmission networks depends on the location. Germany for instance has over 98% of their 1 million plus solar PV plants connected to the decentralized low-voltage grid, most of it being on the low and medium voltage grid (Wirth, 2015), but the classification for the distribution grid can vary widely in voltage from 230 V to 110kV (Volkmar, 2012).

[8] In the US, the meshed network, typically under the jurisdiction of the regional or transmission operator, usually exists between 34.5 kV and 100 kV. Below the 34.5 kV is typically operated radially. Radial lines are typical for low voltage systems due to the ubiquity of unidirectional flow to end-consumers and are typically out of the definition for the bulk electric system (FERC Order No. 773-A).

wanted to provide services into the wholesale market (PJM, 2016). In order the access the market, the curtailment service providers would need to utilize electronic systems, and the system, at first, could not accommodate such decimal places for resources such as demand response, because the only resources that used to access these markets were larger scale central generation resources (PJM, 2016).

Distributed energy resources access wholesale markets through demand response programs behind the meter ordered by state commissions to the electric distribution company (EDC) or by competitive curtailment service providers (CSP), i.e. energy efficiency measures or battery storage in the PJM market (DNV GL Energy, 2014). In the PJM jurisdiction, about 30% of the demand response participation comes from Electric Distribution Company (EDC) programs, whereas 70% comes from "competitive curtailment service providers" (PJM, 2016). Most wholesale markets in the US support demand response integration by having an energy, capacity, regulation or reserve market mechanisms to support demand response integration (IRC, 2014). Wholesale markets in the US allow DERs as a "demand response resource, a production resource or storage resource" (DNV GL Energy, 2014). There are some wholesale markets where distributed energy resources can bid into such as in the forward capacity market in PJM where more than 14 GW of demand response and energy efficiency have cleared over the past 5 years (Newcomb, 2013).

However, allowing distributed resources to participate in wholesale markets through only demand response programs has its limitations. PJM, like NYISO, prohibits power exports from customers that participate in wholesale demand response programs, to distinguish between demand response with and without generation (PJM, 2016). Certain resources can provide services above and beyond a load curtailment service. By placing restrictions, the markets are limiting the services these resources could provide, and therefore reducing the value it could provide to the electricity system.

Energy storage is a technology that could provide a much wider range of services to the power system if certain barriers are overcome. Storage can be modeled as a load as well as a generation resource, and a lack of proper classification of energy storage across multiple markets has led to a limitation of its potential (RMI, 2015). Although energy storage has been a part of US wholesale markets for many years though its role varies from market to market; for instance, Electricity Reliability Council of Texas (ERCOT) defines storage as a generation asset. In the PJM Regional Transmission Organization (PJM RTO), MISO (Midcontinent Independent System Operator), California Independent System Operator (CAISO), and New York Independent System Operator (NYISO) storage is mainly used as a regulation service and paid accordingly to the performance (DNV GL Energy, 2014).

Additional rules limit the participation of DERs in wholesale markets. In NYISO, if an onsite generation resource is operated to reduce load and there is excess generation, it is not allowed to sell the excess into NYISO wholesale markets, but instead must sell it to the local distribution operator via a retail tariff

(DNV GL Energy, 2014)[9]. In contrast, in PJM, market rules for demand response provided with and without distributed generation are basically the same. For the capacity market in PJM, the distribution operator, not PJM, determine the installed capacity that DERs can provide, since the resource is connected at distribution voltage levels (DNV GL Energy, 2014). The Electricity Reliability Council of Texas has designated a separate category for distributed energy resources in markets; defined as a resource below 10 MW connected at distribution voltages. Distributed energy resources below 10 MW are considered a load offsetting resource; therefore, if activated in wholesale markets, the DER is paid the "load zone locational marginal price," as opposed to the nodal price that a generation resource would be paid (DNV GL Energy, 2014). In the PJM jurisdiction, the demand response settlement can be calculated on the "zone, aggregate or node depending on how the site's energy is billed" which means the resource has the capability on deciding how to be billed, due to the nature of these resources and how they perform within the markets (PJM, 2016). DERs face intricate state-jurisdictional processes for interconnection; if DERs are activated in wholesale markets, then they are subject to US Federal Energy Regulatory Commission (FERC) restrictions as well as state level standards/restrictions (De Martini, 2015). Even if DERs are able to meet the criteria to interconnect to the grid, go through the lengthy and complex registration process to be able to physically participate in the market, there is typically a fee to enter the market, which might restrict smaller resources/generators from providing their service.

1.4 Pricing of distributed energy resources

In the United States, most organized wholesale markets (i.e. ISOs/RTOs) typically compute locational marginal prices (LMPs), on hourly or sub-hourly timescales, for economic dispatch that matches supply with demand and incorporates the valuing of energy, losses, and network congestion across zones and nodes. The market operators commit specific power generation units and calculate marginal prices for the transmission networks under reliability constraints. Distribution networks are orders of magnitude larger in scale due to the number of customers, length of wires, system components, complexity of networks and constraints. Calculating locational marginal pricing in the lower voltage distribution network is computationally challenging and not currently adopted in the US; however, co-optimization of services may provide system efficiency gains (Caramanis, 2016).

In the EU, wholesale markets are organized differently than in the US. In the EU, generally speaking, there is a Power Exchange (PX), which runs the spot market (day-ahead and intraday markets), and is separate and apart from the Transmission System Operator, which manages the reserve and network

[9] Depending on the market, retail prices do not always correspond to the wholesale value of energy and a retail tariff might be more profitable (i.e. Net Energy Metering).

constraints market, at the transmission level. To solve network constraints at the transmission level, congestion markets are in place in many countries or other market arrangements are possible, such as bilateral contracts. Most of the member states in the EU electricity market use supply and demand bids that do not consider operational or network constraints, and where reserves and network constraints are handled in separate markets run by the TSO. The EU electricity markets are diverse and contain many different market structures; however, most are abstractions from a single price market, see Table 2 and 3 for more detail. Network constraint markets would need to be adapted to allow DERs to participate, considering, as in the US context, the effect of energy losses.

Pricing services provided by DERs, or valuing their benefits and costs, is necessary to enable more economically efficient markets and operations. Transmission-level services are currently priced differently in the European Union (EU) and US markets and how new distribution-level services will be priced in the future may differ as well. Policy makers and regulators should carefully consider the potential for and tradeoffs between increased scheduling complexity, market power concerns, and other operational challenges when investigating spot or real-time markets at the distribution level (De Martini, 2015).

Currently, most transmission level services are provided by conventional and large-scale generation sources, priced and cleared in wholesale markets. Tables 2 and 3 detail the current methods and categorization of prices and services in the US and EU at the transmission/wholesale level and a first and second-best approach for pricing distribution services[10].

Table 2: ISO and TSO services and pricing in the US and EU, respectively

TSO Services	ISO Services Pricing in the US	TSO Services Pricing in the EU
Electrical Energy	LMPs	Zonal
Transmission Energy Losses		
Transmission Congestion		Congestion Management Markets
Reserves	Co-Optimization with LMPs	Balancing Markets
Reactive Power & Voltage Control	Regulated Prices and Bilateral Contracts	Regulated Prices & Bilateral Contracts
Black-start		

Table 3: DSO services and pricing in the US and EU

[10] First-best pricing is a term that represents the marginal cost based approach to pricing and providing electricity and electricity services. The prices would reflect all the costs associated with providing electricity, including, but not limited to, generation costs, constraints, losses, degradation of infrastructure, and reserves into the formulation for electricity prices. Reliability options are described in more detail in section 3.3.

<table>
<tr><th>TSO Services</th><th>Current Practice for Pricing DSO Services</th><th>Transitory Phase</th><th>First-Best Pricing of DSO Services</th></tr>
<tr><td>Electrical Energy</td><td rowspan="4">Regulated or Competitive Retail Supply Tariffs</td><td rowspan="6">?</td><td rowspan="4">DLMPs or Bilateral Market Clearing Platform</td></tr>
<tr><td>Transmission Energy Losses</td></tr>
<tr><td>Distribution Congestions</td></tr>
<tr><td>Reactive Power & Voltage Control</td></tr>
<tr><td>Network Connection & Reliability</td><td rowspan="2">Averaged Network Tariffs</td><td>Reliability Options/Cost-Reflective Tariffs</td></tr>
<tr><td>Network Deferral</td><td>Cost-Reflective Network Tariffs</td></tr>
</table>

An open question still remains as to an appropriate structure for future pricing of services provided by DERs, be it distribution locational marginal prices (DLMPs), bilateral market clearing, cost reflective network tariffs or average bundled network tariffs. In a truly granular approach to pricing services, wholesale market prices may be extended to lower voltage distribution networks. Wholesale market prices (i.e. locational marginal prices) could be computed at the TSO-DSO interface and then DSOs could theoretically compute distribution locational marginal prices by using an optimal power flow for both active and reactive power; if and only if the market and communication protocols are set so that there is enough time to simulate and calculate these prices, dispatch the services, and optimize across the transmission and distribution system. With DLMPs, congestion and energy losses can be captured. DLMPs may need to be complemented with reserve pricing, network charges and long-term contracts of services (e.g. firm capacity, network deferral, black start) if DLMPs would not fully recover the total cost of distribution networks; therefore, network charges may need to be efficiently designed to allocate the remaining network costs (Pérez-Arriaga & Bharatkumar, 2014; Ntakou & Caramanis, 2015). This topic is being actively researched, but is not yet adopted in the field due to the underlying jurisdictional and operational complexities involved.

1.5 Possible conflicts between electricity services

Services can conflict and compete with one-another within the same level of the grid (e.g. a resource may be able to provide real-time or day-ahead energy, but not capacity). Services can compete across the system; a service utilized at the transmission level, may not be able to provide a service because it creates issues on the distribution system or vice versa (e.g. local network conditions/constraints might not be perfectly reflective of transmission system conditions). Utilization of a distributed energy resource providing a service at the transmission level could, in theory, activate a voltage or some other constraint on the local distribution system, although this is more likely to occur years from now in markets where there is much greater distributed energy resource adoption, or, as previously mentioned, a potential subsequent phase with larger penetration and adoption of distributed energy resources.

A major responsibility of transmission system operators is to balance generation and demand at the bulk power system level, at all times; however, the capacity and interconnection requirements for distributed generation located on the distribution network is currently the responsibility of the DSO. If DERs continue to play a larger role in wholesale markets and provision of services, there will need to be increased cooperation and data exchange between the TSO and DSO when it comes to provision of those services. "TSOs and DSOs should coordinate in solving congestions at the operation planning stage and before real time, and share upfront information about foreseen congestions" (ENTSO-E, 2015). Perhaps new market design rules[11] and frameworks may facilitate TSO and DSO interaction at the interface of transmission and distribution.

Price signals can be a main driver for coordination, and relying on markets might be the most efficient way to allocate resources and services. A market, in theory, and the transactions that are included, could be a mechanism to remove potential conflicts between services, if properly co-optimized and coordinated across levels of the electricity system[12].

2 NEW ROLES OF DISTRIBUTION SYSTEM OPERATORS

In the European context, the DSO has two main roles: system operator and market facilitator (i.e. market operator). A new agent, "an independent platform," can operate and clear the DSO service market. In this paper, it is assumed that the DSO can carry out this role. This paper does not enter into the discussion of independent platforms that might run local markets.

Gaining momentum in the electric and power system industry are the additional roles that distribution system operators might be performing in the future, such as data or information manager, but they are discussed briefly in this paper (evolvDSO, 2015; Chatillon, 2015). This paper considers utilities or DSOs that are unbundled from retail activities, as it is the case in most European markets. In certain US jurisdictions, there are bundled retail and network operations as well as loosely bundled retail activities with electricity services. In New York State there are local utility companies that operate the network, and depending on customer preferences, may or may not be the default supplier. DSOs are responsible for maintaining local constraints within certain specifications and margins, ensuring power quality (i.e. managing harmonics and flicker.), managing Voltage/VAR (i.e. Volt/Volt-Ampere Reactive power) regulation, outage management and reducing energy losses. To fulfill those tasks, DSOs take different actions, such as network planning, network maintenance (preventive and corrective) as well as operation through actions, such as line switching or load shedding during emergency situations.

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[11] DSOs should not be allowed to facilitate the same market that they provide services to (ENTSO-E, 2015).

[12] Transmission, distribution, retail which might include such transactions and markets such as day-ahead, intraday, real-time, forward bi-lateral contracts, and tariff offerings.

2.1 Distribution system operator roles for initial phase of distributed energy resource penetration

With low penetration of DERs, DSOs can maintain and operate their grids reliably via voltage regulation, power factors and phase balances as well as Fault Location Isolation and Service Restoration (FLISR) (De Martini, 2015). FLISR is a process by which DSOs switch power flows over lines, by opening and closing circuits, during periods of operation, for maintenance purposes or more generally to maintain grid reliability. Some forward-looking distribution system operators are gradually increasing the control and monitoring of their distribution grid, at different voltage levels including the distributed resources connected to their grid. In an initial phase, it would be good practice for DSOs to adapt protection systems to handle multi-dimensional power flows and for the system to be able to function in islanding operation in case of outages. In order for DSOs to perform more efficient operations in this initial phase of penetration, DSOs would need to be able to receive availability schedules from all connected users with enough time to perform reliability and security analyses to identify possible grid constraints.

2.2 Distribution system operators roles in subsequent phase of distributed energy resources penetration

In a subsequent phase, with increasing penetration of DERs, there may be a shift in load and generation patterns. In order to operate the network reliably and manage constraints if they arise, DSOs would need schedules from all connected users over different timeframes and perform optimal power flows. DSOs should have at least monitoring and perhaps control over certain grid assets. With increasing penetration of DERs, a DSO might even become an active network manager, facilitating transparent retail markets, owning or operating advanced metering infrastructure, storing data regarding customer loads and resource patterns, as well as newer roles, such as energy efficiency facilitator, as occurred in Denmark, and even potentially controlling infrastructure for electric vehicle charging, whether these functions should be performed by the DSO is still an open question (EDSO, 2012).

With increasing penetration of DERs, it has been suggested that DSOs might take on the role of dispatch coordinator by not only operating their own network, but also coordinating and optimizing with the TSO for scheduling interchanges, perhaps even enabling a more transactive market (Barrager, 2014; De Martini, 2015; GridWise, 2015). More local markets may be necessary to solve local constraints. The topic of local markets is important due to the nature of its dependence or independence from the transmission markets and operations. A distribution system platform provider is a role being discussed throughout New York State in regards to the utilities running local markets/platforms for electricity services (NY Department of Public Service, 2014; Tabors, 2016). Transactive energy is a concept in which markets are used to connect buyers and sellers of electricity services more efficiently. The goal of transactive energy is to enable markets to provide for the economic efficiency, environmental sustainability and reliability for the grid of the future. DSOs in subsequent phases may be the entities sending economic signals to the DERs on their networks, and transactive markets may become utilized in subsequent phases.

As DERs become more prevalent, the likelihood of increased bi-directional flows increases; this could pave the way for new services, such as storage and additional ancillary services to maintain equilibrium of supply and demand (EDSO, 2012). As DERs become ubiquitous on the grid, the increased bi-directional flows and back feed of electricity can cause new complexities and issues for both TSOs and DSOs. For instance, a substation that used to be classified within a load zone, but due to bi-directional flows becomes a generator node for many hours or for set seasons/time-periods, than the ISO/RTO will need to devise a method/mechanism of modeling and dispatching the grid under this possibility.

The intermittency of renewables, larger swings in load, and the mismatch of renewable generation to scheduled forecasts are increasing the difficulty that operators have in matching supply and demand. In the past, the challenge was to match supply with demand. Many operators still have the capability to match demand with supply. With demand response, operators can tweak and utilize mechanisms to change loading patterns. As more DERs become interconnected, it might become more complex or challenging to match demand with supply during high penetration of DERs and low loads, and local challenges such as voltage constraints may become more prolific.

2.3 Long-term planning and procurement of distributed energy resources

Many distribution services and traditional methods for grid stability are mature enough for an initial stage of DER penetration, but as the grid transforms and new resources with complexities of their own are added to networks, alternate schemes for maintaining reliable systems may need to be implemented. When utilities or distribution operators upgrade their system, they typically overbuild the infrastructure to account for years of forecasted load growth; but this is inherently inefficient and costly. In a subsequent phase, or higher penetration of DERs, DSOs could establish more dynamic prices/costs associated with network constraints. To determine prices, market mechanisms need to be created. Currently in the US and EU, market mechanisms such as non-wires alternative solicitations are being considered in which an alternative solution such as a distributed resource could provide a more cost-effective solution as compared to the traditional upgrade or service need. Non-wires alternatives are mechanisms where there is a specific value or avoided cost with deferring infrastructure upgrades, and if an alternative or new solution were proposed more cost-effectively, the resource would be compensated for that service. Solicitations for DERs and targeted alternative solutions may become ubiquitous on the electric grid.

At the distribution level in the EU, different designs might be feasible when pricing DSO services that depend on different variables: product definition, procurement method (i.e. markets, contracts, and incentives), procurement time (i.e. in coordination with existing markets at TSO level and sequential markets), remuneration (i.e. marginal price and opportunity costs) and penalties for non-delivery. Compared to the US, in the EU it is common to have multiple DSOs that operate the distribution systems under a single transmission system; therefore, additional inter and intra-system coordination may be necessary.

When planning for network expansion, operators should understand the status and trends in development and penetration of DERs and consider non-wire solutions as alternatives. Reliability options are one way in which DSOs in the EU, under incentive regulation, can auction firm capacity annually for "[Distributed Generation] DG in network planning" (Trebolle, 2010). A platform may exist in the future, as a basis for pricing products at the distribution level, and facilitating auctions for DSOs to incorporate DERs into functions for long term planning. Integrated and structured planning processes between TSOs and DSOs have also been proposed and are good practices (ENTSO-E, 2015). In certain power systems the Utility receives revenues based on realized costs plus some regulated return on investment, which provides a dis-incentive for the provision of more cost-effective non-wires or non-substation transformer upgrades that might erode profits (i.e. the Utility would have little incentive to pursue cost-saving actions). It is important to shift the traditional remuneration schemes for DSOs and Utilities to perhaps more performance-based metrics and revenue decoupling to better align incentives (Jenkins, 2014; NYS DPS, 2014).

3 INTERACTIONS BETWEEN TRANSMISSION AND DISTRIBUTION SYSTEM OPERATORS DURING THE OPERATIONAL PHASE

Interactions and coordination among the system operators will need to be improved both for shorter time-scale operational actions and longer-term network expansion planning. This section focuses specifically on interactions and coordination between system operators during the operational phase.

Examples of long-term coordination already exist; for instance, the EU has planned a nine-year research program to develop smart grid initiatives and operational coordination between TSOs and DSOs termed the European Electricity Grid Initiative (EEGI). The EEGI seeks to reduce network operating and capital expenditures, increase decentralized renewables and guarantee security of supply and reliability across Europe (Mallet, 2014). The EEGI details a roadmap and objectives, roles for each operator and coordination between the operators as well as budgets for the plan and activities, such as joint research and investigation activities between TSOs and DSOs (Mallet et al., 2014). ENTSO-E has numerous position papers from market frameworks to regulatory governance to security of supply on the interaction between TSOs and DSOs, and describes the key role in Network Codes in defining the different aspects and collaborations between transmission and distribution (ENTSO-E, 2015).

Scarcity of system services are a concern especially for TSOs as there may be a "shrinking pool" of conventional units that provide system services, therefore new arrangements between TSOs and DSOs are needed to fully optimize the use of DERs and maintain security of supply (ENTSO-E, 2015). Information exchange between the operators would need to be ubiquitous regarding the resources connected at the transmission and distribution networks. Schedules and forecasts for demand and generation would need to be sent in real time or prior to real time for activation of services and safe operations of the networks during emergency situations. The TSO and DSOs may need to exchange new information, as detailed below. The format, time and means of the relevant information and communications should be clearly specified in network codes and operational guidelines.

3.1 Energy flows and forecasting

Under an initial phase of distributed resource penetration, there typically has been enough buffer built into electrical grid infrastructure to manage DERs; there is usually hosting capacity available for the distribution circuits to integrate and interconnect DERs up to a certain amount. In this initial phase, however, the relevant hosting capacity information has not widely been disseminated to relevant parties such as developers and consumers that wish to purchase or have access to DERs.

As penetration of distributed energy resources increases, there will be a much greater need for more accurate forecasting of load and generation patterns. DSOs would have the responsibility to monitor more actively the resources and loads connected at distribution voltages and therefore would monitor and may even control resources in order to maintain a balanced grid and solve distribution level constraints. Similar to the transmission level, proper forecasting techniques, scheduling and outage maintenance should be utilized by DSOs to more effectively operate their networks. Distribution system operators in the EU are currently missing this information, and in some rare cases, the TSO actually receives the information from DG resource profiles, bypassing the DSO (Mallet et al., 2014). As DERs change load shapes, the bulk power system operator will need to better-forecast loads and generation. System operators in the US are already integrating forecasting of distributed resource generation on their electric grids (i.e. NYISO and ISONE). Smart metering is essential for market facilitation and reliable system operation with increased penetration of DERs (ENTSO-E, 2015).

3.2 Energy pricing, scheduling, and activation of services

In an initial phase of DER penetration, DERs may act more as passive participants that can provide services to the electric grid incidentally or not as the primary purpose (i.e. solar PV could be used to reduce load onsite through self-consumption during coincident peak hours, thermal or energy storage could be used to load shift, and these DERs may in fact provide electric system-benefits through peak and load reduction as well as providing customer benefits such as bill savings or renewable energy integration).

As larger amounts of DERs become interconnected to the electric grid, and DERs provide services more dynamically, energy schedules, after positions are taken in different markets, need to be shared between the TSO and DSOs to update forecasts and perform power flow analyses closer to real time. Load swings across the day might become wilder, causing the need for greater communication and coordination. Closer to real-time coordination could be captured with a market design that expands the current day-ahead planning which includes DERs and any local constraints. After the day-ahead market, the TSO could inform final schedules of DERs that participate in the market to the DSO. In the same way, if the DSO changes DERs schedules because of local constraints, DSOs would inform the TSO. Lack of schedule information may lead to suboptimal dispatch of the system. In some wholesale markets, such as PJM, some DERs are not registered at the wholesale level and their dispatch is not taken into consideration when running an optimization for the whole system (PJM, 2015). In a subsequent phase, it is important that distributed resources are monitored or visible to grid operators.

Energy prices at the interface between TSO and DSO may be communicated and defined in a hierarchical way. Perhaps, the wholesale market operator could first compute energy prices for the meshed bulk network, then those prices would be sent to the DSOs to incorporate the system conditions and prices into the computation of distribution locational marginal prices or when clearing local markets in radial networks. A market framework should take into account economic optimization of resources, fair competition, transparent rules, data security and confidentiality as well as proper cost allocation (ENTSO-E). As stated before, if DLMPs are not computed, other solutions could be implemented, such as local market mechanisms or value-reflective tariffs.

With greater penetration of DERs, services will need to be activated and final positions determined. Distributed energy resource owners or third party aggregators could take on the responsibility of activation based on dispatch directives, price signals, and penalties for non-fulfillment of commitments. Transmission system operators should not bypass the DSOs regarding information gathering or activation of services in case of emergency issues on the distribution system.

Currently, some DERs, and loads, connected at distribution networks provide services to the ISO, such as in PJM, where Curtailment Service Providers can aggregate different resources to provide economic and emergency demand response (PJM, 2014). Although utilities are informed when DERs register with PJM, utilities are not always informed when activation take place. In a subsequent phase of DER penetration, gaps in communication may cause constraints in distribution networks to occur or to worsen. Protocols for effective communication need to be properly standardized and aligned with actual operations, if not, for example, potential counteractive actions between the different operators and resource activation that has already been exhausted may occur (i.e. a distributed energy storage resource that has depleted its energy capacity, but gets called upon for discharging).

3.3 Emergency situations

In the initial phase of DER penetration, the electric grid, both the bulk power system and distribution networks, are typically reliable enough to maintain supply and demand as well as manage most real-time changes. Electric grids are built with infrastructure that can handle the peak hours of the year when electricity is needed the most and can handle fluctuations in load or supply through network or generator operations and real-time monitoring and control. Most electric grids in the US and EU have very good reliability statistics year after year, with minimal disruptions for the large majority of customers. During emergency situations such as contingency events and outages, when a line trips or is knocked down, sadly those who are connected to the electric system at or near those points of failure, typically lose power for hours, days or even weeks at a time, depending on the length of time that it takes distribution operators to dispatch crews to fix and re-energize the network in a safe manner. One of the major benefits of distributed energy resources is there ability to provide backup power and electricity during grid outages or interruptions.

As DERs become more ubiquitous on the electric grid, more and more customers would have access to backup power and can potentially operate off grid, when the grid has an outage. Perhaps as the penetration of DERs increases, there could be neighborhoods and communities, which during a grid outage, can effectively operate as a microgrid. It is important that grid operators are aware of the distributed assets on their networks, so that they can manage their grids in the most efficient manner and that the full benefits of DERs can be realized.

As penetration of DERs increase, there could also be much larger fluctuations in load and supply depending on the time of day. These variations in load and supply can be managed by energy schedules that capture the relevant changes and forecasts as long as they are monitored, recorded and sent to the operators. The TSO may need support from the DSO to reduce or curtail loads or generation connected to the distribution network. In addition, the DSO may have local issues (e.g. line faults) that may be relevant to communicate to the TSO. Advanced network codes, under a paradigm of high penetration of DERs, need to incorporate new actions and procedures in emergency situations and establish the communication protocols between the operators, such as the Network Code of Emergency and Restoration (CEER, 2015; ACER, 2015).

4 CONLUSIONS

The energy sector is in a period of rapid growth and transformation unlike anything seen in the past century. Decentralization and decarbonization are driving greater penetrations of distributed and renewable energy systems and the subsequent need for greater system awareness, forecasting, and intelligence. Distributed energy resources can provide system services, which may enable even greater penetration of these resources. Specific responsibilities of operators, including coordination and information exchange between the operators, are of utmost importance. The European and the US electricity sectors are taking positive steps towards a decentralized paradigm for enhancing network operations as well as new tariff and market designs.

This paper highlights phases of DER penetration on electric grids in the US and Europe and the interactions between the transmission and distribution system operators. At present, the penetration of DERs is still relatively small, although in many regions the yearly installed capacities are growing rapidly. In initial phases of DER integration, distribution networks are expected to be able to manage the presence of small amounts of DERs. The challenge in this initial phase is to be able to have visibility and monitor the assets on the distribution network.

In a subsequent phase, there could be significantly higher penetration levels of DERs in the system that provides services to the transmission and distribution system. In this subsequent phase, energy and load forecasting, scheduling, activation of resources and procedures to manage emergency situations will need to be defined and implemented. Under these conditions, the DSOs will likely need to perform new functions, such as determining prices for local constraints and coordinating those prices with those of the transmission system operator or wholesale market operator. New market rules and requirements, tariff designs, and price signals could mitigate many of the potential conflicts between services. New wholesale market rules, requirements, and mechanisms for distributed resources to provide services should be codified, as DERs are able to provide system services. Today, there exists a lack of proper market structures, rules, and access as well as compensation mechanisms for DERs to actively provide services across the power system. Coordination between DSOs and TSOs will become increasingly salient as more and more distributed resources interconnect to the grid and provide system services.

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