APPENDIX A

Appendix A
List of Acronyms

AB:	Assembly Bill
BTM:	Behind the Meter
CAISO:	California Independent System Operator
CEC:	California Energy Commission
CEQA:	California Environmental Quality Act
DDOR:	Distribution Deferral Opportunity Report
DER:	Distributed Energy Resource
DERP:	Distributed Energy Resource Provider
DIDF:	Distribution Investment Deferral Framework
DPP:	Distribution Planning Process
DRP:	Distribution Resources Plan
DSO:	Distribution System Operator
ESJ:	Environmental and Social Justice
EV:	Electric Vehicle
EVSE:	Electric Vehicle Supply Equipment
FERC:	Federal Energy Regulatory Commission
GNA:	Grid Needs Assessment
GO:	General Order
GRC:	General Rate Case
ICA:	Integration Capacity Analysis
IDER:	Integrated Distributed Energy Resources
IOU:	Investor-Owned Utility
LNBA:	Locational Net Benefits Analysis
OIR:	Order Instituting Rulemaking
PG&E:	Pacific Gas & Electric Company
PHC:	Prehearing Conference
RA:	Resource Adequacy
SCE:	Southern California Edison Company
SDG&E:	San Diego Gas & Electric Company
TE:	Transportation Electrification

APPENDIX B

Appendix B

An Overview of Distribution System Operator Models

February 2020

This DNV GL study was prepared as Addendum B to DNV GL's February 1, 2020, *Customer Distributed Energy Resources Grid Integration Study: DER Grid Impacts Analysis. In Compliance with Public Utilities Code 913.6. CPUC Legislative Report on Customer Distributed Energy Resources Grid Integration*. Addendum B is circulated as Appendix B to this OIR but was not published with the prior, February 1, 2020, DNV GL report. Page numbering begins at 81 because the study was an addendum to the prior report.

1 INTRODUCTION

The intent of this paper is not to advocate for adoption of a Distribution System Operator (DSO) model or independent DSO, it is instead to describe the concept, contrast it against the current utility-driven Request for Offers (RFO) system, and to use several model examples and the associated discussion to illustrate the concept, and look at how a market-based DSO construct might work and what capabilities would be necessary. The DSO is one of many prominent ideas currently being discussed, explored, and tested in California and other jurisdictions to address the increased penetration of DERs and their impact on all aspects of the Transmission and Distribution grids. The concept of a market driven DER DSO is an extraordinarily complex, continually evolving, and multi-disciplinary model that is still being explored and developed as the electricity markets continue their organic evolution to incorporate DERs. This paper provides high-level ideas and concepts rather than extensive details which are provided in a multitude of other sources, including the few that are cited here.

Although this paper examines the differences between the current utility-driven RFO and market-based DER DSO models, numerous possible intermediate options exist. In fact, wholesale market participation opportunities already exist for DERs within the current industry structure, and the use of RFOs to procure additional DERs for specific grid reliability needs is also being tested in multiple venues. There are still many uncertainties related to DSO models, especially related to their costs, benefits and technology capabilities. Demonstrations projects are being conducted in small scale or isolated environment to help understand some of these questions; so far, these projects are yielding mixed results. The DSO concept has never been deployed at scale. As regulators consider DSO models, the complex elements of the DSO model may be better addressed within the existing framework of workshops, pilot projects, and research efforts associated with the Customer Choice Project, Grid Modernization technology planning, Electric Program Investment Charge program (EPIC program), and/or other CPUC or CEC venues. Although the goal and purpose of a market-based DER DSO model would be to ensure optimized and efficient distributed resources planning, distribution market operations, and distribution market opportunities for DERs, the primary purpose of any investment in the electricity system must be a focus on its ability to provide safe, reliable, affordable, and clean electricity.

Distributed energy resources (DER), such as solar, storage, electric vehicle, and flexible loads, are experiencing rapid technological advances and significant cost reduction, resulting in increasingly high penetration customer-side DERs. However, the electricity system was designed to move electricity one-way: from centralized generation to end-use customers. As such, the grid needs to evolve to support an increasingly distributed system in which bi-directional flow of energy becomes more prevalent.

Traditionally, transmission and distribution operators have had very limited visibility and control over DERs, as DER operations are obscured by the netted load shape. Due to this unpredictability from the perspective of grid operators, DERs have been treated in some cases as a grid liability, where the only goal was to minimize grid impact. To integrate DERs, interconnection rules are in place to ensure proper grid infrastructure is available to support the bi-directional nature of DERs, and time-of-use rates are used to incentivize the timing of import/export to match the system's demand. Demand response is one of the few DER resources that are considered a grid asset. However, with the reality of increasing penetration of DERs, grid operators must be prepared to consider new ways to integrate them. Rather than just minimizing negative grid impacts, grid operators can leverage the resources to improve system stability and reduce of infrastructure upgrade costs via applications such as upgrade deferral, demand response, voltage support, and power quality. This turns the perceived liability of DERs into a possible asset. Transmission system operators are starting to consider new operation rules to allow participation of DERs in the energy and ancillary services markets. Jurisdictions, such as New York and California, are already considering new ways to incentivize more efficient deployment of DERs, including rewarding DERs that can provide grid services where it is needed.

A Distributed System Operator (DSO) model is considered as a platform to facilitate such deployments. The purpose of this report is to describe the key features of a market-based system for distributed energy resource (DER) services, which is often referred to as a DSO model. Under the DSO model, a DSO market entity would control the flow of energy from DERs into the electricity market within a local distribution area. Ideally, a DSO would also facilitate the correct valuation and compensation of DER services, which are essential for effectively targeting the increasing number of locational and temporal load shape issues for transmission and distribution systems. This would allow customers with DERs to monetize the DER's grid value while providing more options and transparency for grid operators to ensure reliability.

In California, DSO functions are currently provided by the utilities, but as the market evolves into a high penetration DER scenario, the utilities' roles will inevitably evolve as well. Utilities, being the most knowledgeable about distribution planning and operations, are well suited to be the DSO administrator. However, it is important to note that utilities primarily have the obligation to serve and they are optimized for managing grid stability and operations to deliver energy to customers. They also are incentivized to earn a rate of return from capital investments, instead of procuring DER services. For a utility-administered DSO to be successful, regulators need to consider performance incentives that are not tied to capital investments. On the other hand, if a third-party is chosen as the DSO administrator, then extra costs related to organizational redundancy must be considered.

This paper will illustrate the key features of different DSO models and compare them to the current utility-driven request for offers (RFO) model (Section 2) and provide case studies as examples of how other jurisdictions are integrating DERs for energy and grid services (Section 3).

2 KEY FEATURES OF THE MARKET-BASED DER DSO MODEL

The goal and purpose of a market based DER DSO model would be to ensure distributed resources planning, distribution market operations, and operational coordination of DERs on an open and non-discriminatory basis to enable wholesale and distribution market opportunities for DERs. Current thinking is that a market-based DSO model for DERs have a market-based DSO model for DERs has the potential to improve the economic efficiency, controllability, and reliability of the distribution grid. The key features that DNV GL reviewed include:

- **DER-DSO services and products:** For both the DSO and RFO model, DNV GL will describe the services and products of the various system entities (e.g. ISO, DSO, utilities, etc.), and how they interact with each other. The section lists some of the market-based services and products which could be supplied by DERs.

- **Roles of DSOs, ISOs, and utilities:** DNV GL will delineate the role of DSOs versus ISOs and utilities, with focus on how the DSO could function to govern a market for distribution grid services as well as the limits of the DSO's responsibilities.
- **Coordination with other market entities:** DNV GL will assess DSO interactions with ISOs and wholesale markets, long term impacts on the DRP proceedings and bulk market, and short-term considerations for system balancing.
- **Costs and benefits from a ratepayer perspective:** DNV GL will outline the benefits, costs, valuation, and compensation of DERs.

2.1 DER-DSO Services and Products

Before discussing how a DSO can be implemented and leveraged, it is key to understand the two options, which are (1) the current RFO based system model and (2) the newer market based DER DSO model:

- **DER services under a utility driven RFO model** describes the system structure, entities/actors, and their roles under DSO model operation. A graphic of this system is provided in Figure B-1.

  DER services under a DSO Model describes the system structure, entities/actors, and their roles under DSO model operation. A graphic of this system is provided in Figure B-2. A side-by-side comparison of the entities and their primary roles and functions for the two models represented in Figures B-1 and B-2 are presented in Table B-1. Red text indicates where there are significant differences in the roles or functions.

Table B-1 Interactions of Electric System Entities Roles and Functions under RFO and DSO Models

Entity	Under RFO Model	Under DSO Model
ISO	**Utility:** Wholesale energy and ancillary services, Scheduling operations	**Utility:** Wholesale energy and ancillary services; Load projections, potentially modified by DER **DER Providers:** DSO market bids, dispatch signals, payment for distribution services **DSO:** Energy and ancillary services, demand modification bids
DSO	**NA:** DSO role served by Utility	**Utility:** Provision of and payment for DER market products, real-time network data, metering **ISO:** Wholesale energy and ancillary services, demand modification bids **DER Providers:** DER services, dispatch signals and payment for DER services **Customer:** Retail energy services
Utility	**ISO:** Wholesale energy and ancillary services, scheduling operations **Customer:** Electric service, reliability, payment of bill **DER Providers:** DER services, RFOs, dispatch signals and payment for services	**ISO:** Wholesale energy and ancillary services; Load projections, potentially modified by DER **Customer:** Electric service, reliability, payment of bill **DER Providers:** NA **DSO:** Provision of and payment for DER market products, real-time network data, metering
DER Providers	**DER Providers:** Wholesale market bids, dispatch signals and payment for wholesale services **Customer:** Payment for use of DER, ability to control and aggregate DER **ISO:** Wholesale market bids, dispatch signals and payment for wholesale services **Utility:** DER services, RFOs, dispatch signals and payment for services	**Customer:** Payment for use of DER, ability to control and aggregate DER **ISO:** Wholesale market bids, dispatch signals and payment for wholesale services **Utility: NA** **DSO:** DER services, dispatch signal and payment for DER services
Customers	**Utility:** Electric service, reliability, payment of bill **DER Providers:** Payment for use of DER, ability to control and aggregate DER	**Utility:** Electric service, reliability, payment of bill **DER Providers:** Payment for use of DER, ability to control and aggregate DER **DSO:** Retail energy services

2.1.1 DER services under a utility driven RFO model

Under a utility-driven RFO model, illustrated in Figure B-1, the relationship between the utility, customers, and the ISO would remain largely the same as in the DSO model, with the utility picking up the DSO functions. The key change is the increasing role of DER providers, who provide distribution grid services as incentivized or dispatched by the utility. Under this model, once the utility identifies a need for distribution grid services, it issues an RFO for service providers to bid on. For example, for a feeder that is approaching maximum load, DER may compete with conventional upgrade solutions. The successful bidder would enter into a contract with the utility to provide the service. Different ownership models may apply: the utility may own and control the DER itself (see Section 3: LADWP DERGIS), or it may interface with an aggregator that is responsible for controlling the DER in response to the utility's needs. The utility may also exert some control over customer sited DER through tariffs or dynamic pricing that incentivize customers to re-shape their consumption profiles. For example, California implemented NEM 2.0 to require all interconnected systems to go under Time of Use tariff in 2016.

The current utility driven RFO model is being tested and continues to evolve as DERs increase. Some of the advantages of the existing mode include:

- **No major regulatory or business model changes are required.** Utilities are already managing DER integration through various mechanisms: interconnection rule, tariffs, and RFP procurements. The system is familiar with all parties, including customers and DER providers. There is a system in place to update the rules and tariffs for continuing to improve DER management.
- **Avoid redundancy.** Utilities are already managing DERs with existing processes, staff, tools, and equipment. If an independent party is opted to administer a DSO, then significant redundancy will occur, at least in the short term.
- **Minimize market disruption.** The existing DER management model allows for incremental improvements and updates through various CPUC proceedings and process improvements. This model is already familiar to customers, DER providers and utilities. Any major changes, such as a move towards DSO implementation, would create significant uncertainty and potentially stifle DER growth in the short term.

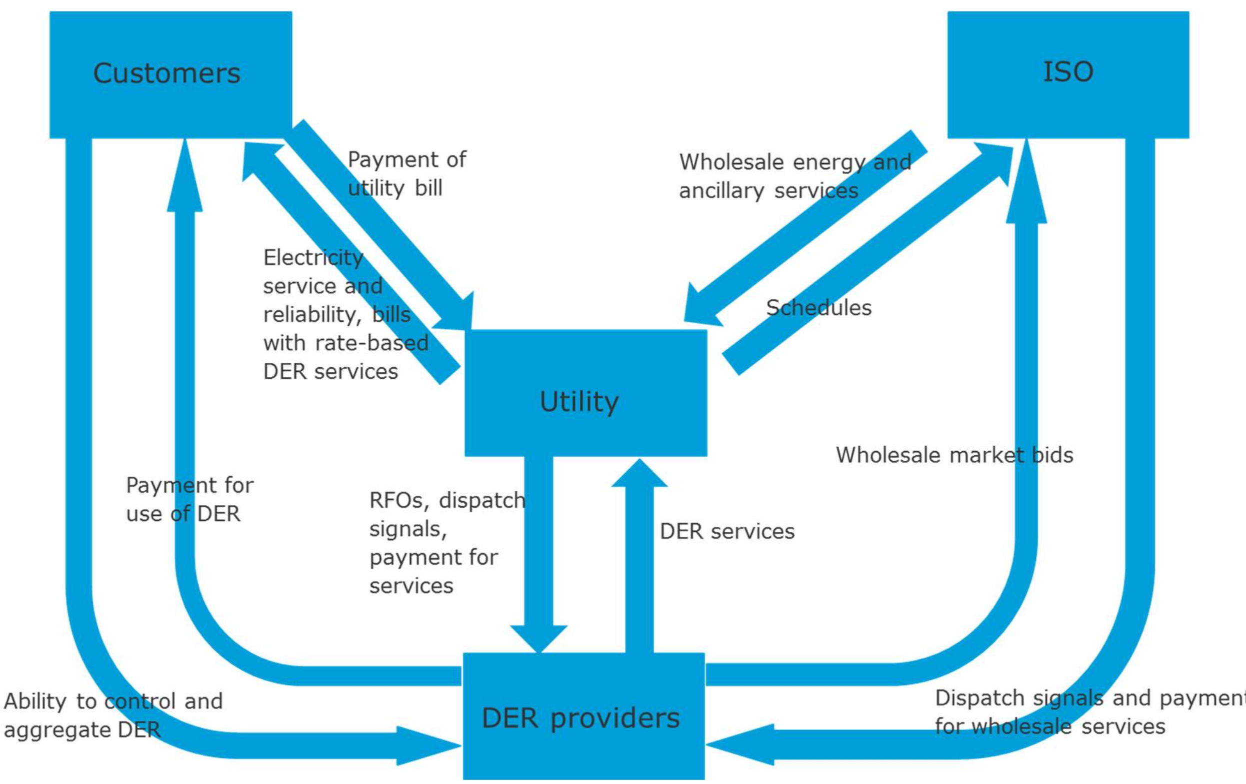

Figure B-1 DER Services Under a Utility-Driven RFO Model

Shortcomings of a utility driven RFO model

However, the incentive structure of a utility-driven RFO model, funded through cost-of-service ratemaking, is going through a paradigm shift because of the increased adoption and efficient use of DER. In DNV GL's research[1] and experience, the RFO model has these key shortcomings:

Lack of incentive to innovate: Utilities may take the approach of "if it's not broken, don't fix it." If a majority of their distribution system is not impacted by high penetration DER, and is not experiencing problems, then they may not see a need to make a systematic change (like a DSO) to their current operation approach until it becomes a bigger issue. In addition, customer-owned, behind-the-meter PV decreases their revenues and further complicates rate design and the regulatory process. They are also already heavily invested in Demand Response programs so may be hesitant to implement other DERs. The regulatory environment might also make it difficult for IOUs to recover expenditures needed to cover any innovation efforts, and even if they want to try something innovative, approval of that effort might take months or years. The litigious nature of utility rate cases is also a huge disincentive for innovation.

Bias toward capital expenditures and own expenditures: DER procured directly by utilities is treated as a capital expense, but a DER solution from a third-party provider would be treated as an operating expense. Utilities have an incentive to favor capital expenses over operating expenses, since operating expenses cut directly into earnings while capital expenses are engineered to allow recovery over time. At the same time, utilities have little incentive to increase efficiency in operating expenses, since a reduction in operating expenses will result in a downward adjustment of rates. In addition, a utility has both financial and institutional incentives to favor its own spending over third-party investments even when third parties may be better able to provide solutions to improve the economic efficiency, reliability, and environmental sustainability of the grid. A utility has an inherent financial interest in discouraging third party involvement, which is inconsistent with optimal investment and operation of the system as a whole.

Asymmetry of information: Utilities have superior knowledge of their distribution network, front-of-meter technologies, costs, and demand, making a traditional RFO process difficult for DER and other solution providers. Making all that information immediately available to DER providers on an open-source basis rather than a sequential, piecemeal RFO process, could help DER providers to identify distribution issues and allow them to propose solutions. On the other hand, DER providers have insight into behind-the meter operation that could be useful to the utilities, so sharing of the information would have benefits for both parties. However, data security and safety issues must be seriously considered, and an open exchange of information may not be possible.

2.1.2 DER services under a DSO model

The DSO concept is envisioned as a way to handle high levels of DER on a distribution system. Although the definition of DSO is still evolving, its main responsibility is to operate a distribution system in a market-efficient manner, specifically with regards to dealing DER integration for its local area. It would also be the interface between the transmission and distribution system for their customers. A detailed description of these roles can be found in a 2015 LBNL report about distribution systems in a high DER future. [4]

DSO (Distribution System Operator). DSO is responsible for the planning and operations of a distribution system within its local distribution area (LDA). Under different DSO sub-models, it could have different sets of functions., It could facilitate the interconnection and monitoring of DERs. It could serve as the interface between the ISO market and DERs under its LDA. It could facilitate an open-access market for DER services.

Utility. A utility can be a DSO; however, the traditional role of utility would be expanded from the RFO model to include monitoring DERs and controlling their entry to the distribution grid. It would facilitate transactions to allow DERs to provide energy and grid services in a continuous manner. Under the New York REV (Reforming the Energy Vision program), the DSO and the utility are the same organizations. This streamlines the organizational structure and operations, and provides a simpler transition from the current model, but raises concerns related to market power. Since utilities have proprietary information about the grid's needs and are incentivized to invest in rate-based capital expenditure, there is a conflict of interest for utilities to procure DERs services. However, if the utility and DSO are separate entities, all distribution operation needs would be competitively evaluated against other options in an open market platform, therefore, eliminating the aforementioned conflicts.

Independent System Operator (ISO) Under the DSO model, the ISO maintains its role as administrator of the wholesale market for energy and ancillary services. The DSO could bid load reduction services into the ISO market as a resource, allowing the ISO to co-optimize bulk power dispatch with DER load reduction and other ancillary services. The utility, if separate from the DSO, would still bid forecast load into the ISO market. Alternatively, if the utility and DSO are the same entity, it could bid pre-optimized load schedules into the ISO market.

DER Providers. A DER provider is an entity responsible for bidding DER services into the DSO market. The DER may be aggregations of small customer-sited devices or larger resources connected to the distribution grid, and the DER provider may own the devices outright or have financial agreements with the owners for control of the DER.

DER providers may also choose to bid directly into the wholesale market.

Customers. Customers will most likely continue to interact with the grid primarily through the utility, which will retain responsibility for billing and infrastructure maintenance. Customers will also have the opportunity to enter into agreements with DER providers to own, lease, or otherwise retain DER that the provider may control and bid into the DSO market.

Large customers with flexible loads, for example, may bid directly into the DSO (or ISO) market.

Figure B-2 below illustrates the function and interactions of the DSO, utilities, ISO, DER providers, and customers under the DSO model.

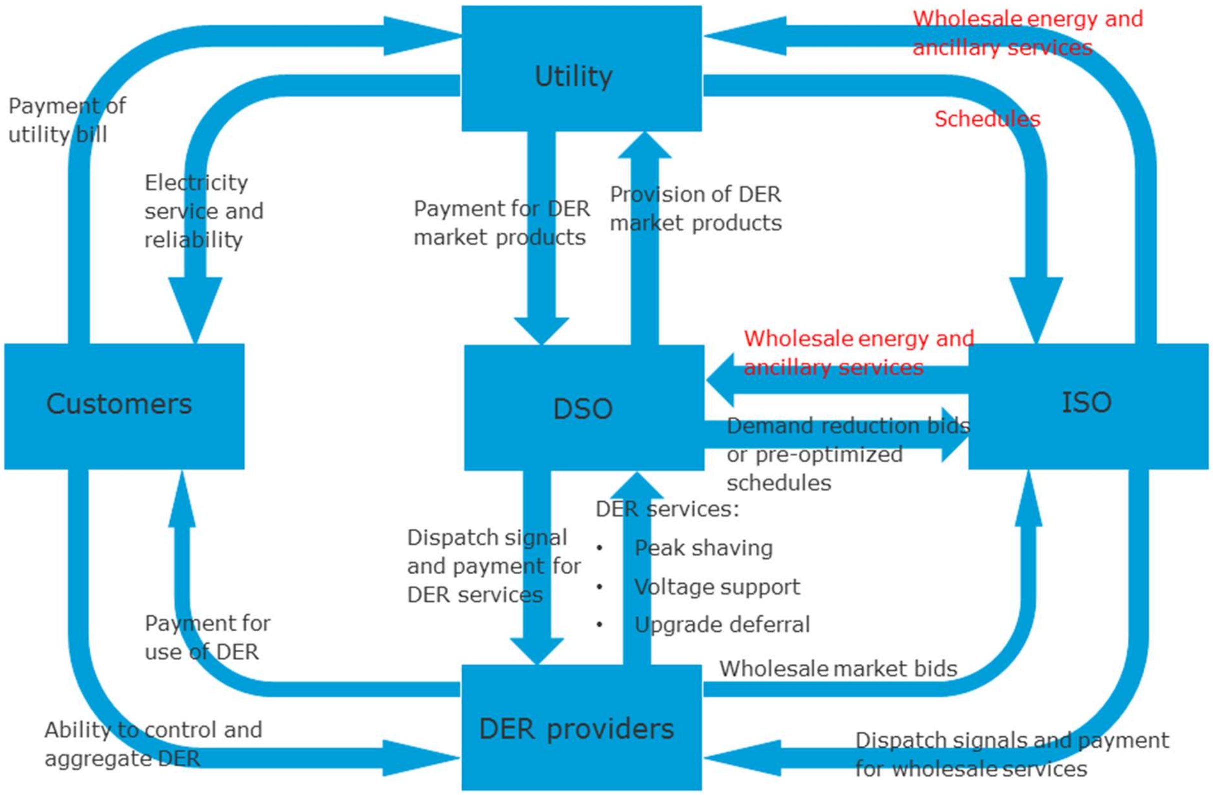

Figure B-2 DER Services Under a Distributed System Operator (DSO) Model

DSO market products and services

There is a wide array of market products and services that DER can provide, and the list will likely continue to increase as both controls and equipment technology advances. Rather than pre-define products to be traded in the DSO markets, NY REV, for example, takes the approach of allowing DER providers to define their own services and bid them into the markets. A similar approach is taken for the California DRP RFO process where, rather than specifying the desired service or technology, the need is defined such that a variety of technology solutions may be proposed. If the market product is sufficiently valuable, the DSO will procure it at greater volumes, other providers will enter the market, and competition will put downward pressure on prices. A non-comprehensive list of DER products that could be bought and sold in a DSO market is provided below, as adapted from reference material [2] and DNV GL experience.

Market products that the DSO would likely procure include:

- Base load modification/over-generation mitigation for local areas;
- Peak load reduction for local areas;
- Non-bulk ancillary services such as distribution-level voltage support, transient power; quality, and line loss reduction

- Bulk ancillary services for aggregation and bidding into the wholesale market;[72]
- Contingency services (reserved for emergency situations); and
- Transmission & Distribution (T&D) upgrade deferral.

Market products that would be sold on the DSO platform would likely include:

- Enhanced resiliency and emergency operational service;
- DER interconnection services;
- Smart technology, smart metering, and load management tools;
- Locational services: DSO determines optimal DER locations and solicits DER solutions from third parties (and potentially the utility);
- Pricing and billing services, including billing for DER aggregators and dynamic pricing;
- DER services such as sale of technology and maintenance contracts;
- Data and information services such as real-time customer usage data for in-home energy management and aggregated market data to inform market participants' decision-making;
- "Park and loan" energy storage services, where energy that cannot be delivered; and immediately can be stored for scheduled delivery at another time.

There are distinct differences in the types of product and services that would be bought or sold, with little overlap. However, if one DSO were to develop expertise in a specific procurement area, then the expertise in those procurement services could also likely be sold to other DSOs.

2.2 Roles of DSO, ISO, and Utilities

There are two key questions regarding DSO governance structure: the first is regarding the DSO's role with respect to the ISO, and the second is regarding its role with respect to the utilities. The DSO could be incorporated with the ISO, with the single entity dispatching the system down to the DER level, or the DSO could function as a separate organization that provides services similar to the ISO but at the distribution level. The role of DSO may be assumed by the incumbent utilities, or the DSO may be established as an independent organization. These contrasting governance structures are further defined, and arguments for and against them summarized, in the remainder of this section.

2.2.1 Delineating the role of DSO versus ISO

The role of the DSO in managing the distribution system is similar to the role that CAISO serves for the bulk market. A significant difference is that the DSO under most scenarios would typically not be a single statewide entity, but rather multiple entities serving a region, local distribution area (LDA), or transmission-distribution interface (T-D interface), or some combination of these. As such, to illustrate the possible DSO configurations and roles for a high penetration DER scenario, several DSO models from the LBNL/Caltech paper and slide deck [4] are discussed in detail below:

- **The "Total TSO Model":** Under this model, there is no DSO because all DSO functions would be performed by the TSO with DER monitoring and control extending into the distribution circuit.
- **The "Minimal DSO Model":** For this model, the DSO would be responsible for the physical coordination of all DER activities, and a key feature is that the T-D interface would be the information and coordination point with the TSO.
- **The "Market DSO Model":** This model is a simplification of the "Total TSO model" in that to participate in the market, DERs must be aggregated to a minimum size. This model is actually comprised of two scenarios because the DSO can serve as either 1) a coordinator for multiple DER aggregators, or 2) an aggregator itself. For both scenarios, a single resource is provided at each T&D interface to the TSO.

Key features and characteristics of each of the models are summarized below.

The "Total TSO Model"

Under this model, the DSO would have little or no role in distribution-level market services because monitoring, dispatching, and controlling would all be done at the TSO (CAISO) level. DERs down to a relatively small size would be fully integrated and dispatched by the TSO. DERs would be represented at their actual locations and the TSO's control would extend to the distribution circuit. Of all the scenarios that can be imagined, this it is the least feasible due to the significant technical and regulatory challenges. First and foremost, the technical challenge of installing monitoring and controlling equipment on a significant portion of the smaller DER systems, and then dispatching both T&D assets in response to the distribution systems, would likely be complex and more susceptible to smaller disturbances. On the regulatory side, it would require cooperation between FERC and state regulators, which could be a challenge. Because the TSO/ISO wholesale markets are under federal jurisdiction, while the retail, local distribution systems are under state jurisdiction, an unprecedented amount of coordination would be required. In addition, control by the TSO/ISO might tend to favor large, central solutions for economic (participant fees, transmission access charges, etc.) and historic reasons, although they would likely not be able to ignore the organic growth of DERs.

The "Minimal DSO Model"

This model differs from the Total TSO model in that control and visibility to the distribution system ends at the T-D interface, which is also where it is begins for the DSO. From the TSO perspective, for dispatch purposes the DERs are assumed to be at the T-D interface, rather than modeling the distribution circuits and physical locations of the DERs. The DSO would be responsible for the physical coordination of all DER activities, especially those that impact the distribution system or require response to TSO dispatches. The DSO would provide distribution services including interconnection to the distribution system and coordinating wholesale market participation. The DSO could also end up sourcing distribution grid services from the same wholesale market-participant DERs as under the TSO model. An important requirement of this model is that the DSO will need to have real-time communication and operating procedures with the TSO, as well as with the DER providers in the DSO's LDA, to ensure reliable operation of the distribution system. Because the TSO will not have visibility beyond the T-D interface, it will not know how its dispatched of DER are affecting the distribution system conditions. In that case, it would be up to the DSO to monitor, manage, and respond accordingly to the conditions.

The "Market DSO Model"

This model is a simplification of the Total TSO model in that, to participate in the market, DERs must be aggregated to a minimum size. For example, a minimum requirement of 10 MW could be required for participation in the economic dispatch or wholesale market. This model is actually two sub-models because it includes two scenarios. The DSO can serve as either: 1) a coordinator for multiple DER aggregators, or 2) an aggregator itself. For both scenarios, as with the Minimal DSO model, a single resource is provided at each T-D interface to the TSO. For both cases, it would be the DSO's responsibility to coordinate the responses of the DER aggregators and/or the individual DERs.

For the first sub-model scenario, the "DSO as coordinator of DER aggregators", the coordination function is complicated by multiple aggregators on the same LDA. Each aggregator would be independently submitting bids to and responding to dispatches from the wholesale market, which would all need to be coordinated by the DSO.

For the second sub-model scenario, the "DSO as aggregator of DERs", the DSO role is simpler. Under this scenario, the DSO's role for the distribution system is analogous to the role of the ISO for the transmission system. The DSO would also serve as the scheduling coordinator for the TSO market and, upon receiving a TSO dispatch, would decide which local DERs could best respond to the need. In this case "best" would imply most economically and without having a detrimental impact on the distribution system. The DSO would also balance the LDA supply-demand by importing or exporting as needed across the T&D substation. This model is the simplest model in regard to the interactions and coordination required between the DSO, TSO and DERs for a given LDA. However, it does not allow DERs to participate directly in the wholesale spot market, so the process would need to be very transparent to ensure regulatory non-discrimination requirements are satisfied.

2.2.2 Delineating the role of DSO versus utilities

Key challenges in defining the governance structure of the DSO include avoidance of too much market power, appropriate accountability for distribution grid reliability, and integration with existing governance structures. NY REV, for example, has designated utilities to serve as the DSOs (or Distribution Service Platforms—DSPs—in REV terminology). Other experts, notably John Wellinghoff, the former chairmen of the Federal Energy Regulatory Commission (FERC), argues that despite the advantages of utilities serving as DSOs, only a DSO that is completely independent from the utility can guard adequately against market power and ensure economic efficiency. DNV GL's references [4] contain a full discussion of the appropriateness of different DSO governance structures given the stage of industry evolution and the prevailing market or utility structure (i.e. vertically integrated or wholly or partially deregulated).

Arguments in favor of incumbent utilities as DSOs include:

- **Close connection between utility and DSO operations.** The system planning and operations responsibilities of the DSO are the responsibility of the utilities under the current model, such that an independent DSO could result in extra cost and organizational redundancy.
- **Streamlining of DSO creation and regulation.** Incumbent utilities serving as DSOs could initially be regulated under the current framework; the regulatory status of a new, independent entity would need to be determined.

- **Utilities are well positioned to facilitate immediate DER growth.** Utilities' incumbent knowledge of their own distribution systems and in-house expertise on resource planning, operations, and customer engagement would be assets in launching a transition to a DSO model. Economies of scale in utility DER investment could aid initial market development. They are also most aware of the portions of their distribution systems that are experiencing problems and can predict what portions may be an issue in the near future (via requests for interconnections, etc.).
- **An independent DSO may not entirely mitigate market power.** A utility that was motivated to exercise market power could potentially still do so through preferential operation of the distribution system, data manipulation, or influencing the DER market through its investment decisions.
- **Utilities could serve as DSOs initially, before a transition to an independent DSO.** The utility's performance as DSO would be periodically evaluated, and as DSO markets and operations become more established, it may be pertinent to transition to an independent DSO model. However, establishing an independent DSO from the outset could save costs relative to transitioning from a utility DSO.

Arguments in favor of independent DSOs include:

- **Smoother state-wide coordination and standardization.** Incumbent utilities serving as DSOs would create a patchwork that could encumber the establishment of uniform market practices across the state.
- **Avoidance of market power.** Utilities' monopoly status would create the opportunity to exert undue influence in a DSO market, resulting from the utilities' commercial interest in DER and customer load management combined with its control over access to the distribution network and dispatch of DER. A utility serving as DSO may see a financial incentive to maintain barriers to DER market penetration, such as inadequate data provision, tariffs that do not fully value DER, and cumbersome interconnection requirements.
- **Potential for less status-quo bias and greater promotion of innovation.** Under an independent DSO and market-based DER system, ideally there would be an emphasis on the best cost, most reliable and safe product or service to meet the distribution or transmission system need, rather than first choosing the most readily available utility-owned resource. Emphasizing the actual system need versus a specific technology or service should also promote innovation.

Utilities functioning as DSOs raise the question of whether they should be permitted to own DERs. Prohibiting utilities from owning DERs would mitigate concerns about market domination. However, even in a market environment, utility ownership of DER may be beneficial under certain circumstances. Utility-owned DER co-located with distribution system assets may be a cost-effective way to support system reliability, for example. In these circumstances, which would likely need regulatory approval, utility procurement of the DER would follow an RFO process.

Jon Wellinghoff has consistently advocated for an independent DSO model. For example, in comments to the New York Department of Public Service [4], Wellinghoff and co-authors state that "[j]ust as traditional management of the grid by vertically integrated utilities was inadequate to support the changing needs of the transmission grid, we posit that management of the New York distribution system by utilities alone will not be sufficient to sustain a resilient, clean, least cost, and innovative grid." The conflict of interest inherent in the utilities owning and controlling access to the distribution system, they argue, is too great to enable efficient DER deployment.

If the utilities continue to own the distribution infrastructure and are separate from an independent DSO, there is a question as to whether the utilities should be responsible for distribution engineering analysis, DER interconnection studies and procedures, DER hosting capacity analysis, distribution grid design, and switching/outage restoration and distribution maintenance. One concern is that the utilities' planning functions will be biased in favor of their own rate-based investments in distribution assets. This may be mitigated if the utility performs these functions as part of a larger planning process for which another entity (the DSO or TSO) is primarily responsible. Likewise, non-discrimination concerns exist regarding operational functions may be mitigated by expanding existing regulatory mechanisms [4].

2.3 Coordination with ISO and interaction with wholesale market

One of the primary roles of the DSO will likely be to coordinate the interface between the transmission and distribution systems, and to ensure that a DER that is committed to providing transmission-level services and can deliver those services through the distribution system. This includes ensuring that a DER does not have conflicting commitments to provide both transmission-level and distribution-level services. The DSO will need to coordinate the operational, though not necessarily financial, aspects of transactions between distribution-level actors (e.g. DER aggregators, municipal utilities) and the bulk system [5].

A DER that is operated to shave load peaks for distribution system upgrade deferral will reduce bulk-system costs as well. Lower peak load in the wholesale market will result in lower utilization of less-efficient peaking units (primarily gas plants), lowering costs and improving air quality, and eventually avoiding construction of such units entirely. Further, peak-shaving at the distribution level will reduce transmission congestion into high-load areas, potentially avoiding construction of additional costly transmission capacity. These benefits depend on visibility and controllability of DER, which a DSO market would help incentivize. On the other hand, DER that is not dispatchable and transparent at the bulk system level would increase uncertainty at all time scales in ISO planning, from operations to investments, contributing to increased system costs.

Considerations in the relationship between the DSO and ISO include:

- Ensuring that DER providers are compensated according to the benefits they furnish to both the distribution system and bulk system. One way to accomplish this would be for DSOs to aggregate the activity of DER for bids into the wholesale market.
- Evaluate potential conflicts between ISO/DSO dispatch instructions.
- The potential for unforeseen consequences to ISO day-ahead and real-time processes. In planning DER integration into wholesale markets, attention must be paid to avoiding any potential unforeseen consequences at the wholesale level that could degrade system reliability or contribute to operational uncertainty.

Further, there are issues that must be addressed regarding the prioritization of dispatch instructions from the ISO and DSO:

- If DSO's are self-balancing, can they either reduce their flexibility needs from the ISO to zero, or provide flexibility services up to the ISO?

- Can distribution deferrals be reliable on the presence of potential conflicting dispatch instructions from the ISO?
- The limits of the DSO's responsibilities would need to be clearly specified and detailed.
- Which services could be market-based would need to be clearly identified, specifically, which could be supplied by DER.

2.3.1 Long-term impacts of DRP proceedings on bulk system balancing

Under the Distribution Resource Plan (DRP) guidance ruling, utilities are responsible for the distribution system planning functions, but increased transparency in the planning process is necessary, via such modes as stakeholder review and regulatory oversight. As noted in DNV GL's references, "[t]his oversight extends to the authorization of subsequent decisions regarding the use of DERs as alternatives to utility investment through rate cases and other rate-setting proceedings." [4]

DERs could provide flexibility and reliability services to the grid, reduce ancillary service needs, and meet dynamic reserve requirements. The DRP process would need to investigate and determine if an independent DSO is needed to ensure the planning process is transparent. In this role, the DRP could have a significant long-term impact on the investigation and assessment of the feasibility for a DSO model to work in California. However, given that the regulatory environment generally moves more slowly than market developments, especially regarding the deployment of DERs and the DSO model, it will be an on-going challenge for the DRP to evolve and keep up.

2.3.2 Short-term considerations for system balancing

There are a number of critical short-term issues that should be considered and pursued to understand the potential of a DSO model that can successfully fulfill the system balancing function. These are noted below.

- **Demonstration projects:** Due to the complexity of operation, performing demonstration projects in a somewhat isolated environment or portion of the grid will be one of the best ways to evaluate and assess a DSO system. A microgrid environment could provide a good test-bed environment. Pilot projects such as the ones recently approved in New York are good examples of this method. In support of the NYISO DER Roadmap, three pilot projects involving front-of-the meter batteries, solar and +storage, and curtailable load configurations will be tested. Demonstrating the potential for these products to service both the retail and wholesale markets is a critical objective for these projects. (see Buffalo Niagara Medical Campus in Section 3).
- **Interconnection requirements:** Under a DSO model, the interconnection requirements will need to be updated to ensure reliable communication and control of the DERs. With high-penetration DERs, a major distribution system issue will be bi-directional power flow across the system, and DERs would be interconnected to allow dispatch or curtailments. As microgrids become more prevalent and capable of islanding, DSO operations will also need to coordinate micro-grid interconnections. In addition, there is the DSO-TSO interconnection via the T&D interface. The DSO will need to coordinate all of the interconnections, making the distribution system operation much more complex than it is now.
- **Monitor NY REV activities:** New York State's Reforming the Energy Vision (REV) initiative intends to implement a DSO model, with utilities initially fulfilling the role of DSO. Monitoring the progress of

NY REV would give CPUC insight into the feasibility, potential challenges, and any unforeseen costs, risks, or benefits of the DSO model. The information provided above on the recently approved NYISO DER pilot studies is a perfect example of this work.

2.4 Costs and benefits from a ratepayer perspective

Although the primary role of the DSO would be to optimize deployment of DERs while maintaining the reliability and safety of the distribution system, a major emphasis of California's Distributed Resources Plan (DRP) is to "minimize overall system cost and maximize ratepayer benefits from investments in preferred resources." A few of the benefits, costs, and other impacts from a ratepayer perspective to be considered under a DSO model are discussed below.

2.4.1 Benefits

Based on DNV GL's research and experience, potential benefits of the relationship between the DSO and ISO could ideally include:

- **Increased distribution grid reliability and resiliency.** Visible, dispatchable DER could align with the increased use of advanced distribution-level sensors and control devices to improve voltage regulation, fault detection, and outage recovery. Access to DSO market data could enable the utility to better incorporate DER activity into grid operations and planning, which could ideally increase grid reliability and resiliency. In contrast, continued organic growth in customer-owned, behind the meter systems without operational information and telemetry data for those systems, could decrease grid reliability and stability.
- **Reduced electricity prices.** Assuming the DSO model results in increased economic efficiency, electricity prices to consumers will decrease. This should be the result of the combined effect of reduced wholesale prices, primarily due to peak load reduction, efficient DER operations, and deferred distribution as well as potentially transmission network upgrades.
- **Protection against high network charges resulting from utility revenue erosion.** If DER deployment continues in the absence of a framework to actively integrate it, utility revenue may decrease to the point that utilities would have to raise rates significantly to maintain their existing levels of service and system responsibilities. This would likely have the most impact on low-income customers who are unable to afford DER.
- **Increased control over energy use and costs.** Ratepayers will be newly able to actively manage their energy consumption patterns and will have greater choice in the use of DERs to maximize their value, including providing grid services. Ideally, the market would incentivize consumer engagement through pricing mechanisms designed to nudge consumer choices into alignment with efficient operation of the distribution-level and bulk-level systems. Although DER customers would need to provide information and potentially control to the DSO, they could benefit from the increased telemetry and system control themselves both monetarily and more visibility into their system's performance.
- **Avoid NIMBY opposition to new transmission lines and power plants.** Increased penetration and efficient use of DERs could help avoid the need for construction of new transmission lines and large power plants, which often draws opposition from ratepayers in local

communities. Going further, ideally the DSO would be able to motivate the market to offer more DER options to meet ratepayer-customer needs while also improving grid reliability, safety, and operation.

- **Standardized DER products and services.** An independent DSO could potentially also facilitate the standardization of products, services, and costs, ensuring more consistent products that would make it easier for market participants to make comparisons. However, the amount of standardization would likely be limited as the needs for every circuit and service area are unique and would likely require some customization of most services and products.

2.4.2 Costs

Ratepayer costs are much more difficult to define because there are a multitude of complex and different costs and regulatory issues under both the current and DSO system, many more than can be discussed and detailed in this report. There are not just monetary costs, but also privacy and control costs. However, a few of the primary cost considerations are discussed below.

- **Start-up and infrastructure costs**. Regardless of the exact DSO model, it will take substantial investments to build out and characterize all of the key aspects of a DSO model, such as market and operation rules, economic models, control centers, monitoring, control and communication systems. Since no DSO has been implemented at scale, it is unknown how much the start-up costs would be to develop a DSO system.
- **Inequity of customer-owned/leased DER devices.** Customers may choose to purchase DERs outright. These are most typically solar (PV), batteries, and EVs. This transaction would entail an initial lump-sum cost followed by benefits that accrue over time and would favor higher-income customers who can afford the up-front investment. Other models, such as leasing DER equipment from a provider, could help make DERs available to more of the population. Utilities, regulatory bodies, and the DSO should consider how best to equitably serve low-income customers under a DSO model.
- **Program administrative costs.** Ratepayers would ultimately bear the administrative cost of implementing a DSO model, including the increased measurement and verification needs as well as improved metering and communications systems. However, ideally these increased costs would be offset by more realistic pricing of the DER production to reflect temporal and locational value, versus a more general time of use metering approach. Customers would also incur a non-monetary cost in the form of having to cede some privacy and control of their DER system to the DSO.
- **Reliability costs.** Some DERs do not have the reliability, flexibility, and certainty of a dispatchable, fossil-fueled power plant, so back-up/reserve costs incurred by the utility or DSO would be added to the ratepayer costs.
- **Valuation and compensation.** There is much debate around, and many regulatory issues related to how to accurately value and pay for DER services and products, especially for non-dispatchable technologies, and given the locational and temporal grid variations that are the result of DER penetration.

2.4.3 Other Challenges

Additional factors that could impact ratepayers and adoption of the DSO model include:

Uncertainty surrounding customer acceptance and participation. As previously mentioned, the monitoring and control role of the DSO would require the intrusive installation of metering and control devices on the customer's DER, and many customers may resist the intrusion. Furthermore, having to deal with yet another entity such as a DSO in addition to a DER provider and utility might be difficult to explain to the typical residential customer, and therefore serve as a barrier to acceptance.

Split incentives. DER services may be subject to the "landlord-tenant problem," in which a building owner may be reluctant to invest in DER, since only the tenants, who pay the electricity bills, would reap the benefits. DER pricing plans would need to address this scenario.

Reliability/Resiliency concerns. With climate change and every successive year getting warmer and fires burning more frequently and fiercely in California, reliability and resiliency will remain a critical issue for California utilities and ISO. In at least one area, market conditions created by greenhouse gas and renewable goals created conditions in which economic decisions were made to close two gas plants, but "must-run" orders were issued by CAISO to keep these uneconomic plants running to maintain system reliability. The addition of yet another entity such as a DSO might actually decrease reliability and resiliency by adding one more layer to the system.

Security/Hacking. Regardless of configuration for the DSO model, the data needed will require additional sensor-monitoring points. Every additional point could be another opportunity to hack into the grid's information and control systems. Utilities have very strict data security requirements placed on them by FERC, and any additional threat vectors will be very heavily scrutinized.

Utility business model. Under DSO models where capital investments could be shifted to third parties, it is unclear how utilities would continue to operate. The DSO would duplicate much of the utility's existing administration, and the utilities' role would be greatly diminished. If utilities were to administer the DSO, the utilities' business model would need to be shifted away from earning a profit on capital investments and be incentivized to operate an efficient DSO market.

Governance. It is unclear how a new, independent entity would be regulated if the DSO is not the regulated utilities. If ISO takes on more DER management activities, it is unclear how to delineate the roles of the local regulator versus FERC.

3 CASE STUDIES AND PROGRESS TOWARDS DSO MODELS

A review of global system operators and utilities shows that most are aware of the growing penetration of DERs, and their potential to impact the grid. DNV GL has not, however, found a jurisdiction where there is currently a competitive open DSO market for DERs to provide capacity or grid services. Domestically, to better integrate DERs, several jurisdictions, such as those within New York and California, are conducting pilot projects to assess the operational and commercial barriers for DERs to participate in the wholesale and distribution markets. The results of these pilots will start to become available in 2019.

In Europe, the concept of DERs providing bulk energy supply or flexibility is still in its infancy. Although there are virtual power plants that aggregate different DERs, the DERs primarily serve other commercial purposes. Even though some local administrators or incumbent vertically integrated utilities may use DERs to provide high levels of self-supply and independence, they do not control the DERs or have a market-based mechanism to procure services from them. The only simulation of a market-based DSO we found is a study conducted by DNV GL for the Swiss Federal Office of Energy that was considering procuring DERs services in a local flexibility market. Since the domestic pilot projects are very similar to the demonstrations that are already being conducted in California, the following summary focuses on the Switzerland study which is most resemble a market-based DSO model.

In the sections below, DNV GL has summarized several studies and pilot projects regarding the integration of DERs to provide energy or ancillary services for the grid. Key takeaways from these studies include:

- DERs can provide energy and grid services under the current market constructs: through utility RFP procurements or aggregated bids to the wholesale market. DERs participating in the wholesale market is a relatively new concept; however, there are pilot projects under way to demonstrate the cost-benefit and clarify market participation rules.
- DERs procured in an open DSO market can be a cost-effective solution for grid services under specific conditions and locations. As DER costs fall and technologies improve, the cost-effectiveness of DERs in comparison to traditional alternatives will continue to improve, and thus be effective in a competitive market model.
- Education on the cost-effectiveness of DERs providing grid services for utilities and continued funding of technology development are key features in a developing a DER market and aging grid.
- The regulatory and market frameworks needed to be overhauled to enable efficient DER participation in the wholesale and distribution market. These tend to be the key barriers for DERs to participate in the wholesale market and for DSO implementation.

3.1 Switzerland - Activation of Local Market DERs for Flexibility Services

In 2015, the Swiss Federal Office of Energy conducted a cost-benefit analysis of using a traffic light model in the Swiss electricity distribution grid. [8] The traffic light model, a novel concept first considered by Germany,[73] enables the use of DERs by distributed network operators[74] to alleviate local network congestion. In the traffic light model, the traffic light with "yellow" or "red" light would indicate potential congestion in a DSO network, e.g., voltages issues, or thermal readings on transformers in excess of rated limits. The purpose of the traffic light scheme is to avoid infrastructure investment to address these issues, by leveraging an alternative option to maintain grid stability.

During the yellow phases, the DSO contracts local or regional flexible resources in its own technology-neutral, competitive market platform (the flexibility market) to compensate for bottlenecks in the distribution grid. In the red phases, where it is no longer possible to resolve the bottlenecks by local flexible resources, the DSO intervenes with grid-stabilizing measures in the operation of the system markets.

A prerequisite for this concept is the implementation of suitably accurate and networked sensors in the distribution grids, to enable the DSO to assess the grid conditions. In addition, this concept raises several regulatory prerequisites that must be in place before implementation:

1. The expected size of the flexibility market (number of suppliers) must be sufficient to guarantee competition.
2. There must be a complete unbundling of grid operations and generation operations to avoid conflicts of interest of the DSO.
3. The traffic light model should be the most cost-effective, technical solution for the cost of bottleneck management.

This study focuses on addressing the cost-effectiveness pre-requisite (#3 above). The analysis benchmarks the costs and benefits of the traffic light model in two ways to ensure reliable operation of the grid: (1) conventional grid expansion, and (2) expansion with controllable local grid stations. The study conducted simulations of costs and benefits under different DER growth scenarios, network configurations (rural, semi-urban, urban), and smart grid technology setups and investments. For the traffic light model, it is assumed that a complete rollout with smart meters would have taken place by 2035, so that only the remaining IT and communications technology would be added to the traffic light model for cost aggregation.

DNV GL's simulation results show that there is a need for a traffic light model only after 2020, in a scenario with ambitious expansion of renewable energy. In rural distribution grids, which are characterized by comparatively low load and high decentralized feed-in energy from renewables, the traffic light model proves to be unsuitable: the traffic light changes between green and red phases as DERs respond to market price signals and stop producing when congestion happens. In fact, it has negative consequence because there is no marginal cost in PV generation. In the traffic light model, PV systems would not react at all if the prices are positive, and as soon as the critical price limit falls below, they would all switch off at the same time.

By contrast, the traffic light model can resolve bottleneck situations in urban distribution grids where there are high-load grid conditions and medium to high penetration of communications and IT technologies. With sufficient number of flexible loads, demand side management is more cost-effective under the traffic light model because demand is price sensitive. In addition, there are indirect benefits of the traffic light model because the information about grid status provided in the traffic light model is valuable to DSOs for other purposes.

From the regulatory perspective, these issues are observed:

- Bottlenecks tend to occur in the lower voltage levels due to the expansion of PV and wind; the distribution grid operator as a single buyer faces only a very limited number of potential providers of flexibility. If there are not enough providers, there is risk of collusion due to the proximity.
- The organization of a decentralized market for flexibility is another important point. The large number of distribution grid operators operating on low and medium voltage in Switzerland makes individual operation of a flexibility market seem cumbersome. On the other hand, the distribution grid operator is the only one who has grid-relevant data that needs to be communicated to the

market in near real-time. Accordingly, an interface of central flexible market operators and DSO would have to be administered.

- A traffic light model requires extensive unbundling of grid operation from the power supply. If this is not ensured, there could be disincentives for the distribution system operator to favor flexibilities from the connected supply area by intentionally causing yellow traffic light phases. Without strict firewalls, the coverage area could access proprietary information about the condition of the grid and the levels of other flexible resources available. Such extensive unbundling seems unlikely in the fragmented grid operator structure in Switzerland.
- From a regulatory standpoint, the question arises as to how it can be ensured that the flex market is the cost-effective alternative to congestion management. While the costs of building conventional grid, expansion are easily predictable and the price for procuring contracted system service is known, the scope and costs of the traffic light model is largely unknown. This is because the cost of the traffic light model would depend on the number of flexibility events, the supply of flexible resources and the ultimate market price for the flexibility services.

3.2 New York ISO DER Pilots

New York Independent System Operator will be conducting pilot projects to demonstrate DER capabilities and wholesale market integration. The pilots would help modify market design and improve operational coordination processes among different stakeholders. According to a press release from July 2018 [10], the DER aggregation project includes:

- Front-of-the-meter batteries to demonstrate coordination of multiple DERs to be effectively dispatched by the NYISO or Con Edison depending on system needs or conditions;
- Front-of-the-meter batteries co-located with solar to evaluate the ability of such aggregated resources to provide both wholesale and retail services, and
- High-rise buildings with curtailable (readily adjustable) energy load to evaluate the capability of building management systems to provide ancillary services.

The current market rules do not support these types of projects, so the demonstration testing will be performed in an environment separate from NYISO's production market. The demonstration testing is expected to begin in the first half of 2019.

3.3 New York Virtual Power Plant Pilot Program

In New York, Con Edison developed a Virtual Power Plant pilot program along with SunPower and Sunverge Energy. This project is designed to demonstrate how aggregated fleets of solar and energy storage assets in hundreds of residential dwellings can collectively provide network benefits to the grid, resiliency services to customers, monetization value to Con Edison, and results that will inform future rate design and development of distribution-level markets. At this time, the pilot has encountered delays due to permitting issues with Fire Department of New York (FDNY). Project costs and benefits are not yet available.

3.4 NY REV – Buffalo Niagara Medical Campus DSP Test-bed

New York's Reforming the Energy Vision program, or REV, is a comprehensive energy strategy for New York State. REV is intended to, in part, develop new energy products and services to protect the environment. One of REV's demonstration projects, which was approved as of June 2016, is being conducted at the Buffalo Niagara Medical Campus (BNMC). This project, with a team comprising National Grid, BNMC, and Opus One (a software engineering company), is intended to develop, deploy, and test a new distribution-level energy market solution. As noted in National Grid's filing [9], the purpose of this project is to develop and test solutions based on a local, small-scale, but centralized DSP that would communicate with network-connected points of control (POC) associated with BNMC DERs. The POC would be hosted on a server at a customer's site with communications capabilities to control DER assets based on events on the electric power system and contractual agreements in place with the local DSP provider.

The proposed local DSP would communicate the electric distribution system needs of the local substation and feeders and send dynamic pricing signals to the POCs. The POCs would communicate with the DSP as to the availability of BNMC DERs to respond to local electric system needs and the willingness to accept pricing signals. Within the "market" of the BNMC, the Project will evaluate what price signals and/or other revenue opportunities motivate BNMC member institutions with DER capabilities to provide the DSP with local electric distribution system services at the POC level, and what revenue opportunities would encourage additional DER investment. Based on the most recent quarterly report available online (Q1 2018) the project has achieved the following milestones: technology development, design, DSP user acceptance testing, POC user acceptance testing, and proof of concept go-live, among others. The project is scheduled to complete in Q2 2019.

3.5 LADWP DERIS Study

The Los Angeles Department of Water and Power (LADWP) examined an approach-model in their Distributed Energy Resource Integration Study (DERIS) [4]. This scenario assumed a fully-managed DER portfolio with centralized control of the process (management, planning, deployment, etc.). The study used the key characteristics of LADWP's system to create an optimal DER portfolio, with the key goal to produce an economic benefit to the ratepayers. Results of the study are shown graphically in Figure B-3, which illustrates a much smoother shape for the "managed DER" scenario on the right, in comparison with the "unmanaged DER" scenario on the left. To reach the high level of DER penetration, the scenario assumes that customer incentives would be offered, and that special tariffs would incentivize customers to allow their DER systems to be managed by LADWP. Additionally, implementing this scenario would require large investments in distribution system management systems, DER management systems, and SCADA systems to gather the data necessary for monitoring and management.

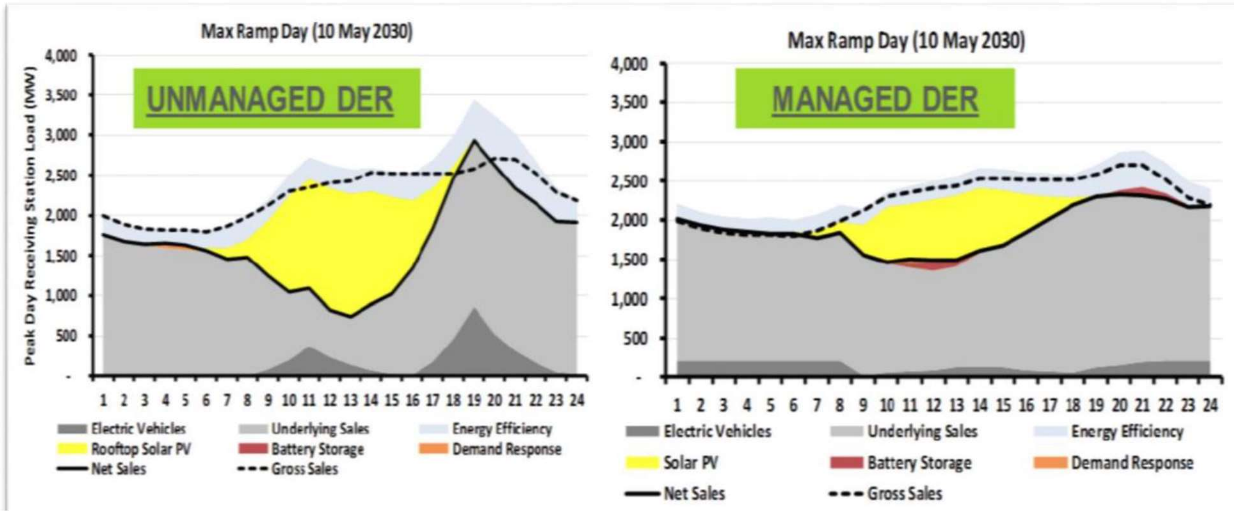

Figure B- 3 Example of Fully Managed DER Simulation for LADWP

To achieve this, LADWP is considering three business models for implementing DER aggregation in the LADWP service territory. The three models considered were:

1. LADWP acting as DER aggregator and provides energy, capacity, and/or distribution deferral services through coordination and control of the DER aggregation for the benefit of its ratepayers.
2. A third-party act as aggregator and offers services through a competitive solicitation to LADWP. This report describes how a competitive solicitation might be structured to ensure that the risk of engaging with a third-party is minimized.
3. Hybrid model where a third-party aggregator presents the value proposition to the customer, may own the customer-side equipment, managed installation and customer services. The distribution system monitoring, billing and other responsibilities related to customer compensation continue to be managed by LADWP

LADWP is currently studying the cost-benefit of these options, as well as the potential for lower penetration scenarios. The results will impact LADWP's implementation and resource plans.

3.6 ARPA-E NODES

the Advanced Research Projects Agency-Energy (ARPA-E), is a segment of the United States Department of Energy which aims to provide funding for "high-potential, high-impact energy technologies that are too early for private-sector investment" with the goal of "radically improving US economic prosperity, national security, and environmental well-being" through energy research projects. The ARPA-E NODES, or Network Optimized Distributed Energy Systems, Program is working to enable renewable penetration at the 50% level or greater by developing transformational grid control methods that optimize use of flexible load and DER.

Twelve different projects are currently funded in this program; DNV GL itself is supporting one program titled "Enabling the Internet of Energy through Network Optimized Distributed Energy Resources." It is in its second year of work on this project, which is focused on the development and testing of the Internet of Energy (IoEn) platform for the automated scheduling, aggregating, dispatching, and performance validating of network optimized DERs and controllable load. The IoEn platform is intended to simultaneously manage both system level regulation and distribution level support functions to facilitate large-scale integration of distributed generation onto the grid. The platform is intended to demonstrate the ability of customer-sited DERs to provide grid frequency regulation and distribution reliability functions with minimal impact to their local behind-the-meter demand management applications. The IoEn will be demonstrated and tested at Group NIRE's utility-connected microgrid test facility in Lubbock, Texas, where it will be integrated with local utility monitoring, control and data acquisition systems. By increasing the number of local devices able to connect and contribute to the IoEn, this project aims to enable to increase of renewables penetration which maintaining high levels of grid performance.

4 CONCLUSIONS

As stated in the Introduction, the intent of this paper is not to advocate for adoption of a Distribution System Operator (DSO) model or independent DSO, it is instead to describe the concept, contrast it against the current utility-drive RFO system, and to use several model examples and the associated discussion to illustrate the concept, and look at how a market-based DSO construct might work and what capabilities would be necessary. The DSO is one of many prominent ideas currently being discussed, explored, and tested in California and other jurisdictions to address the increased penetration of DERs and their impact on all aspects of the T&D grids. The concept of a market driven DER DSO is an extraordinarily complex, continually evolving, and multi-disciplinary model that is still being explored and developed as the electricity markets continue their organic evolution to incorporate DERs. There are still many uncertainties related to DSO models, especially related to their costs, benefits and technology capabilities. Demonstrations projects are being conducted in small scale or isolated environment to assist with understanding some of these questions; so far, these projects are yielding mixed results. The DSO concept has never been deployed at scale. As regulators consider DSO models, the complex elements of the DSO model may be better addressed within the existing framework of workshops, pilot projects, and research efforts associated with the Customer Choice Project, Grid Modernization technology planning, the EPIC program, and/or other CPUC or CEC programs. Although the goal and purpose of a market-based DER DSO model would be to ensure optimized and efficient distributed resources planning, distribution market operations, and distribution market opportunities for DERs, the primary purpose of any investment in the electricity system must be a focus on its ability to provide safe, reliable, affordable, and clean electricity.

Additional issues and recommendations to be considered for future research efforts include:

- The electricity market will continue to evolve towards decarbonization, electrification, and incorporation of the menagerie of DERs. Change will not come overnight, and the smaller-scale (T-D interface, feeder line, etc.) incremental changes offer great opportunities for pilot studies and lessons learned that can be applied to smart evolution of the larger ecosystem and active load shape management. There are still many uncertainties related to the DSO concept. The CPUC should continue demonstration projects to assess the value of DERs on a locational and time of day basis. This would contribute to evaluating the cost and benefits of a DSO model. Pilot projects can also be devised to test out potential operational and market rules, and how the technologies can meet these requirements.

- In addition to administration and regulation, valuation, especially temporal and locational, and compensation for DER-based resources are important issue. The capacity of DERs to forego or delay upgrades to over-loaded transmission or distribution lines is an essential part of the valuation.
- Because the DSO concept is developing so quickly, a more detailed report on this research effort would be better suited as a monthly or quarterly newsletter versus a static report.
- The definition of DERs is also an issue. DERs are a true menagerie of options and configurations, so it may not be sufficient to discuss the whole basket of DERs but instead break these down further into groups by technology, capability, location, size, etc. for further discussions about their integration.
- The taxonomy used to discuss DERs and DSOs is evolving on a daily basis. Creating an authoritative list of definitions, terms, concepts, and configurations as used for California applications could help ensure consistency in discussions and could help focus the system evolution.
- A variety of system modeling efforts are underway that would allow more detailed system cost and impact assessments to be performed. These efforts should be catalogued and monitored to identify tools that can be used to better assess concepts like the DSO model. CPUC should continue to monitor DER pilot projects in other jurisdictions and study their lessons learned.
- It is important to consider role of utilities in a DSO model to ensure a sustainable business model for utilities that are obligated to serve.

5 WORKS CITED

[1] State of New York Public Service Commission, "CASE 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.Order Adopting a Ratemaking and Utility Revenue Model Policy Framework.," 2016.

[2] Reforming the Energy Vision (REV) Working Group 1: DSPP Markets, "Staff Report on the work of the DSPP Markets Committee," 2014.

[3] P. De Martini, L. Kristov and L. Schwartz, "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation, and Oversight," Lawrence Berkeley National Laboratory, 2015.

[4] J. Wellinghoff, K. Hamilton and J. Cramer, *Comments on Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Case No. 14-M-0101,* 2014.

[5] L. Kristov and P. De Martini, *21st Century Electric Distribution System Operations,* 2014.

[6] DNV GL, "Cost-benefit Analysis of a Traffic Light Model Solution for the Electricty Market of Switzerland," Swiss Federal Office of Energy (BFE), Ittigen, Switzerland, 2015.

[7] New York Independent System Operator, "NYISO Announces Distributed Energy Resource Pilot Projects," 26 7 2018. [Online]. Available: https://home.nyiso.com/press/press-release-nyiso-announces-distributed-energy-resource-pilot-projects/. [Accessed 3 8 2018].

[8] National Grid, "REV - Demonstration Projects - BNMC DSP Engagement Tool," 17 June 2016. [Online]. Available: www.dps.ny.gov/REVDemos.

[9] D. Erickson, "Market Architectures for Managing Distributed Energy Resources," E3R Consulting, Philadelphia, 2018.

[10] State of New York Department of Public Service, "Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Developing the REV market in New York: DPS staff straw proposal on Track One issues," 2014.

[11] F. Rahimi and S. Mokhtari, "A New Distribution System Operator Construct," Open Access Technology International, Inc., Minneapolis, MN, 2014.

1 INTRODUCTION

The intent of this paper is not to advocate for adoption of a Distribution System Operator (DSO) model or independent DSO, it is instead to describe the concept, contrast it against the current utility-driven Request for Offers (RFO) system, and to use several model examples and the associated discussion to illustrate the concept, and look at how a market-based DSO construct might work and what capabilities would be necessary. The DSO is one of many prominent ideas currently being discussed, explored, and tested in California and other jurisdictions to address the increased penetration of DERs and their impact on all aspects of the Transmission and Distribution grids. The concept of a market driven DER DSO is an extraordinarily complex, continually evolving, and multi-disciplinary model that is still being explored and developed as the electricity markets continue their organic evolution to incorporate DERs. This paper provides high-level ideas and concepts rather than extensive details which are provided in a multitude of other sources, including the few that are cited here.

Although this paper examines the differences between the current utility-driven RFO and market-based DER DSO models, numerous possible intermediate options exist. In fact, wholesale market participation opportunities already exist for DERs within the current industry structure, and the use of RFOs to procure additional DERs for specific grid reliability needs is also being tested in multiple venues. There are still many uncertainties related to DSO models, especially related to their costs, benefits and technology capabilities. Demonstrations projects are being conducted in small scale or isolated environment to help understand some of these questions; so far, these projects are yielding mixed results. The DSO concept has never been deployed at scale. As regulators consider DSO models, the complex elements of the DSO model may be better addressed within the existing framework of workshops, pilot projects, and research efforts associated with the Customer Choice Project, Grid Modernization technology planning, Electric Program Investment Charge program (EPIC program), and/or other CPUC or CEC venues. Although the goal and purpose of a market-based DER DSO model would be to ensure optimized and efficient distributed resources planning, distribution market operations, and distribution market opportunities for DERs, the primary purpose of any investment in the electricity system must be a focus on its ability to provide safe, reliable, affordable, and clean electricity.

Distributed energy resources (DER), such as solar, storage, electric vehicle, and flexible loads, are experiencing rapid technological advances and significant cost reduction, resulting in increasingly high penetration customer-side DERs. However, the electricity system was designed to move electricity one-way: from centralized generation to end-use customers. As such, the grid needs to evolve to support an increasingly distributed system in which bi-directional flow of energy becomes more prevalent.

Traditionally, transmission and distribution operators have had very limited visibility and control over DERs, as DER operations are obscured by the netted load shape. Due to this unpredictability from the perspective of grid operators, DERs have been treated in some cases as a grid liability, where the only goal was to minimize grid impact. To integrate DERs, interconnection rules are in place to ensure proper grid infrastructure is available to support the bi-directional nature of DERs, and time-of-use rates are used to incentivize the timing of import/export to match the system's demand. Demand response is one of the few DER resources that are considered a grid asset. However, with the reality of increasing penetration of DERs, grid operators must be prepared to consider new ways to integrate them. Rather than just minimizing negative grid impacts, grid operators can leverage the resources to improve system stability and reduce of infrastructure upgrade costs via applications such as upgrade deferral, demand response, voltage support, and power quality. This turns the perceived liability of DERs into a possible asset. Transmission system operators are starting to consider new operation rules to allow participation of DERs in the energy and ancillary services markets. Jurisdictions, such as New York and California, are already considering new ways to incentivize more efficient deployment of DERs, including rewarding DERs that can provide grid services where it is needed.

A Distributed System Operator (DSO) model is considered as a platform to facilitate such deployments. The purpose of this report is to describe the key features of a market-based system for distributed energy resource (DER) services, which is often referred to as a DSO model. Under the DSO model, a DSO market entity would control the flow of energy from DERs into the electricity market within a local distribution area. Ideally, a DSO would also facilitate the correct valuation and compensation of DER services, which are essential for effectively targeting the increasing number of locational and temporal load shape issues for transmission and distribution systems. This would allow customers with DERs to monetize the DER's grid value while providing more options and transparency for grid operators to ensure reliability.

In California, DSO functions are currently provided by the utilities, but as the market evolves into a high penetration DER scenario, the utilities' roles will inevitably evolve as well. Utilities, being the most knowledgeable about distribution planning and operations, are well suited to be the DSO administrator. However, it is important to note that utilities primarily have the obligation to serve and they are optimized for managing grid stability and operations to deliver energy to customers. They also are incentivized to earn a rate of return from capital investments, instead of procuring DER services. For a utility-administered DSO to be successful, regulators need to consider performance incentives that are not tied to capital investments. On the other hand, if a third-party is chosen as the DSO administrator, then extra costs related to organizational redundancy must be considered.

This paper will illustrate the key features of different DSO models and compare them to the current utility-driven request for offers (RFO) model (Section 2) and provide case studies as examples of how other jurisdictions are integrating DERs for energy and grid services (Section 3).

2 KEY FEATURES OF THE MARKET-BASED DER DSO MODEL

The goal and purpose of a market based DER DSO model would be to ensure distributed resources planning, distribution market operations, and operational coordination of DERs on an open and non-discriminatory basis to enable wholesale and distribution market opportunities for DERs. Current thinking is that a market-based DSO model for DERs have a market-based DSO model for DERs has the potential to improve the economic efficiency, controllability, and reliability of the distribution grid. The key features that DNV GL reviewed include:

- **DER-DSO services and products:** For both the DSO and RFO model, DNV GL will describe the services and products of the various system entities (e.g. ISO, DSO, utilities, etc.), and how they interact with each other. The section lists some of the market-based services and products which could be supplied by DERs.

- **Roles of DSOs, ISOs, and utilities:** DNV GL will delineate the role of DSOs versus ISOs and utilities, with focus on how the DSO could function to govern a market for distribution grid services as well as the limits of the DSO's responsibilities.
- **Coordination with other market entities:** DNV GL will assess DSO interactions with ISOs and wholesale markets, long term impacts on the DRP proceedings and bulk market, and short-term considerations for system balancing.
- **Costs and benefits from a ratepayer perspective:** DNV GL will outline the benefits, costs, valuation, and compensation of DERs.

2.1 DER-DSO Services and Products

Before discussing how a DSO can be implemented and leveraged, it is key to understand the two options, which are (1) the current RFO based system model and (2) the newer market based DER DSO model:

- **DER services under a utility driven RFO model** describes the system structure, entities/actors, and their roles under DSO model operation. A graphic of this system is provided in Figure B-1.

  DER services under a DSO Model describes the system structure, entities/actors, and their roles under DSO model operation. A graphic of this system is provided in Figure B-2. A side-by-side comparison of the entities and their primary roles and functions for the two models represented in Figures B-1 and B-2 are presented in Table B-1. Red text indicates where there are significant differences in the roles or functions.

Table B-1 Interactions of Electric System Entities Roles and Functions under RFO and DSO Models

Entity	Under RFO Model	Under DSO Model
ISO	**Utility:** Wholesale energy and ancillary services, Scheduling operations	**Utility:** Wholesale energy and ancillary services; Load projections, potentially modified by DER **DER Providers:** DSO market bids, dispatch signals, payment for distribution services **DSO:** Energy and ancillary services, demand modification bids
DSO	**NA:** DSO role served by Utility	**Utility:** Provision of and payment for DER market products, real-time network data, metering **ISO:** Wholesale energy and ancillary services, demand modification bids **DER Providers:** DER services, dispatch signals and payment for DER services **Customer:** Retail energy services
Utility	**ISO:** Wholesale energy and ancillary services, scheduling operations **Customer:** Electric service, reliability, payment of bill **DER Providers:** DER services, RFOs, dispatch signals and payment for services	**ISO:** Wholesale energy and ancillary services; Load projections, potentially modified by DER **Customer:** Electric service, reliability, payment of bill **DER Providers:** NA **DSO:** Provision of and payment for DER market products, real-time network data, metering
DER Providers	**DER Providers:** Wholesale market bids, dispatch signals and payment for wholesale services **Customer:** Payment for use of DER, ability to control and aggregate DER **ISO:** Wholesale market bids, dispatch signals and payment for wholesale services **Utility:** DER services, RFOs, dispatch signals and payment for services	**Customer:** Payment for use of DER, ability to control and aggregate DER **ISO:** Wholesale market bids, dispatch signals and payment for wholesale services **Utility: NA** **DSO:** DER services, dispatch signal and payment for DER services
Customers	**Utility:** Electric service, reliability, payment of bill **DER Providers:** Payment for use of DER, ability to control and aggregate DER	**Utility:** Electric service, reliability, payment of bill **DER Providers:** Payment for use of DER, ability to control and aggregate DER **DSO:** Retail energy services

2.1.1 DER services under a utility driven RFO model

Under a utility-driven RFO model, illustrated in Figure B-1, the relationship between the utility, customers, and the ISO would remain largely the same as in the DSO model, with the utility picking up the DSO functions. The key change is the increasing role of DER providers, who provide distribution grid services as incentivized or dispatched by the utility. Under this model, once the utility identifies a need for distribution grid services, it issues an RFO for service providers to bid on. For example, for a feeder that is approaching maximum load, DER may compete with conventional upgrade solutions. The successful bidder would enter into a contract with the utility to provide the service. Different ownership models may apply: the utility may own and control the DER itself (see Section 3: LADWP DERGIS), or it may interface with an aggregator that is responsible for controlling the DER in response to the utility's needs. The utility may also exert some control over customer sited DER through tariffs or dynamic pricing that incentivize customers to re-shape their consumption profiles. For example, California implemented NEM 2.0 to require all interconnected systems to go under Time of Use tariff in 2016.

The current utility driven RFO model is being tested and continues to evolve as DERs increase. Some of the advantages of the existing mode include:

- **No major regulatory or business model changes are required.** Utilities are already managing DER integration through various mechanisms: interconnection rule, tariffs, and RFP procurements. The system is familiar with all parties, including customers and DER providers. There is a system in place to update the rules and tariffs for continuing to improve DER management.
- **Avoid redundancy.** Utilities are already managing DERs with existing processes, staff, tools, and equipment. If an independent party is opted to administer a DSO, then significant redundancy will occur, at least in the short term.
- **Minimize market disruption.** The existing DER management model allows for incremental improvements and updates through various CPUC proceedings and process improvements. This model is already familiar to customers, DER providers and utilities. Any major changes, such as a move towards DSO implementation, would create significant uncertainty and potentially stifle DER growth in the short term.

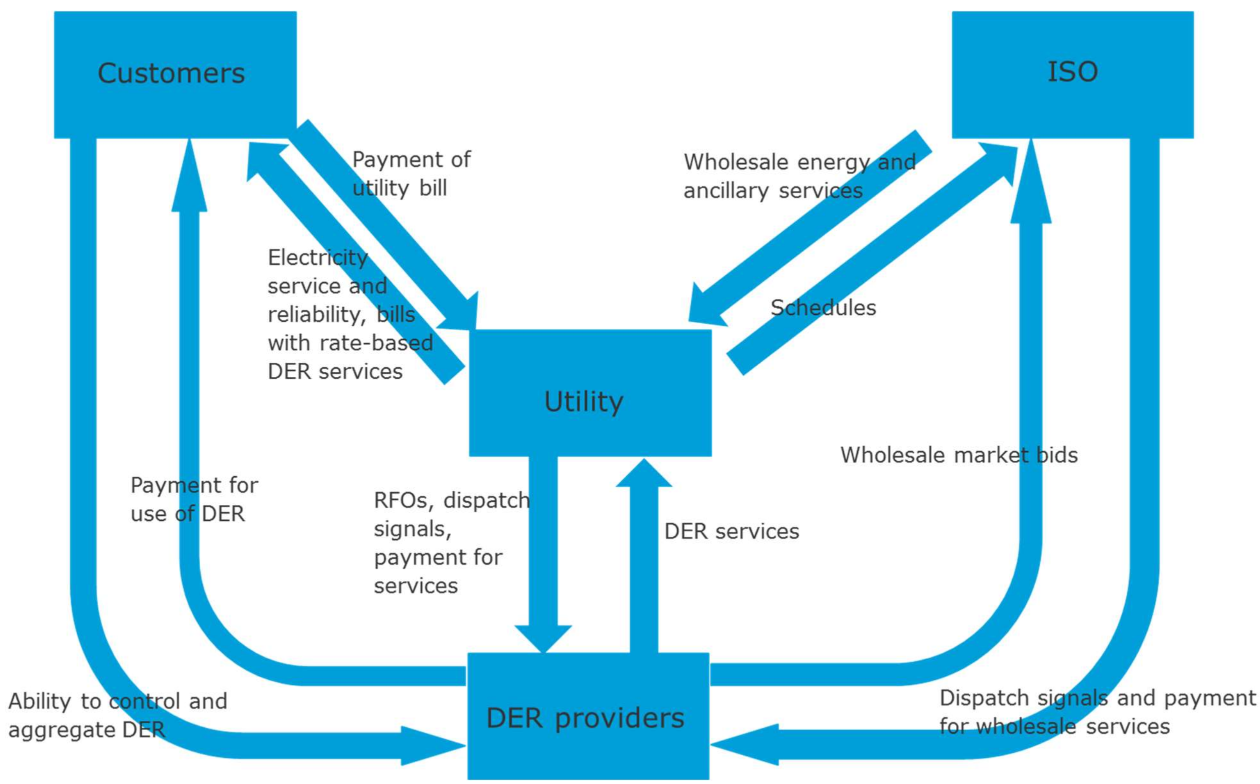

Figure B-1 DER Services Under a Utility-Driven RFO Model

Shortcomings of a utility driven RFO model

However, the incentive structure of a utility-driven RFO model, funded through cost-of-service ratemaking, is going through a paradigm shift because of the increased adoption and efficient use of DER. In DNV GL's research[1] and experience, the RFO model has these key shortcomings:

Lack of incentive to innovate: Utilities may take the approach of "if it's not broken, don't fix it." If a majority of their distribution system is not impacted by high penetration DER, and is not experiencing problems, then they may not see a need to make a systematic change (like a DSO) to their current operation approach until it becomes a bigger issue. In addition, customer-owned, behind-the-meter PV decreases their revenues and further complicates rate design and the regulatory process. They are also already heavily invested in Demand Response programs so may be hesitant to implement other DERs. The regulatory environment might also make it difficult for IOUs to recover expenditures needed to cover any innovation efforts, and even if they want to try something innovative, approval of that effort might take months or years. The litigious nature of utility rate cases is also a huge disincentive for innovation.

Bias toward capital expenditures and own expenditures: DER procured directly by utilities is treated as a capital expense, but a DER solution from a third-party provider would be treated as an operating expense. Utilities have an incentive to favor capital expenses over operating expenses, since operating expenses cut directly into earnings while capital expenses are engineered to allow recovery over time. At the same time, utilities have little incentive to increase efficiency in operating expenses, since a reduction in operating expenses will result in a downward adjustment of rates. In addition, a utility has both financial and institutional incentives to favor its own spending over third-party investments even when third parties may be better able to provide solutions to improve the economic efficiency, reliability, and environmental sustainability of the grid. A utility has an inherent financial interest in discouraging third party involvement, which is inconsistent with optimal investment and operation of the system as a whole.

Asymmetry of information: Utilities have superior knowledge of their distribution network, front-of-meter technologies, costs, and demand, making a traditional RFO process difficult for DER and other solution providers. Making all that information immediately available to DER providers on an open-source basis rather than a sequential, piecemeal RFO process, could help DER providers to identify distribution issues and allow them to propose solutions. On the other hand, DER providers have insight into behind-the meter operation that could be useful to the utilities, so sharing of the information would have benefits for both parties. However, data security and safety issues must be seriously considered, and an open exchange of information may not be possible.

2.1.2 DER services under a DSO model

The DSO concept is envisioned as a way to handle high levels of DER on a distribution system. Although the definition of DSO is still evolving, its main responsibility is to operate a distribution system in a market-efficient manner, specifically with regards to dealing DER integration for its local area. It would also be the interface between the transmission and distribution system for their customers. A detailed description of these roles can be found in a 2015 LBNL report about distribution systems in a high DER future. [4]

DSO (Distribution System Operator). DSO is responsible for the planning and operations of a distribution system within its local distribution area (LDA). Under different DSO sub-models, it could have different sets of functions., It could facilitate the interconnection and monitoring of DERs. It could serve as the interface between the ISO market and DERs under its LDA. It could facilitate an open-access market for DER services.

Utility. A utility can be a DSO; however, the traditional role of utility would be expanded from the RFO model to include monitoring DERs and controlling their entry to the distribution grid. It would facilitate transactions to allow DERs to provide energy and grid services in a continuous manner. Under the New York REV (Reforming the Energy Vision program), the DSO and the utility are the same organizations. This streamlines the organizational structure and operations, and provides a simpler transition from the current model, but raises concerns related to market power. Since utilities have proprietary information about the grid's needs and are incentivized to invest in rate-based capital expenditure, there is a conflict of interest for utilities to procure DERs services. However, if the utility and DSO are separate entities, all distribution operation needs would be competitively evaluated against other options in an open market platform, therefore, eliminating the aforementioned conflicts.

Independent System Operator (ISO) Under the DSO model, the ISO maintains its role as administrator of the wholesale market for energy and ancillary services. The DSO could bid load reduction services into the ISO market as a resource, allowing the ISO to co-optimize bulk power dispatch with DER load reduction and other ancillary services. The utility, if separate from the DSO, would still bid forecast load into the ISO market. Alternatively, if the utility and DSO are the same entity, it could bid pre-optimized load schedules into the ISO market.

DER Providers. A DER provider is an entity responsible for bidding DER services into the DSO market. The DER may be aggregations of small customer-sited devices or larger resources connected to the distribution grid, and the DER provider may own the devices outright or have financial agreements with the owners for control of the DER.

DER providers may also choose to bid directly into the wholesale market.

Customers. Customers will most likely continue to interact with the grid primarily through the utility, which will retain responsibility for billing and infrastructure maintenance. Customers will also have the opportunity to enter into agreements with DER providers to own, lease, or otherwise retain DER that the provider may control and bid into the DSO market.

Large customers with flexible loads, for example, may bid directly into the DSO (or ISO) market.

Figure B-2 below illustrates the function and interactions of the DSO, utilities, ISO, DER providers, and customers under the DSO model.

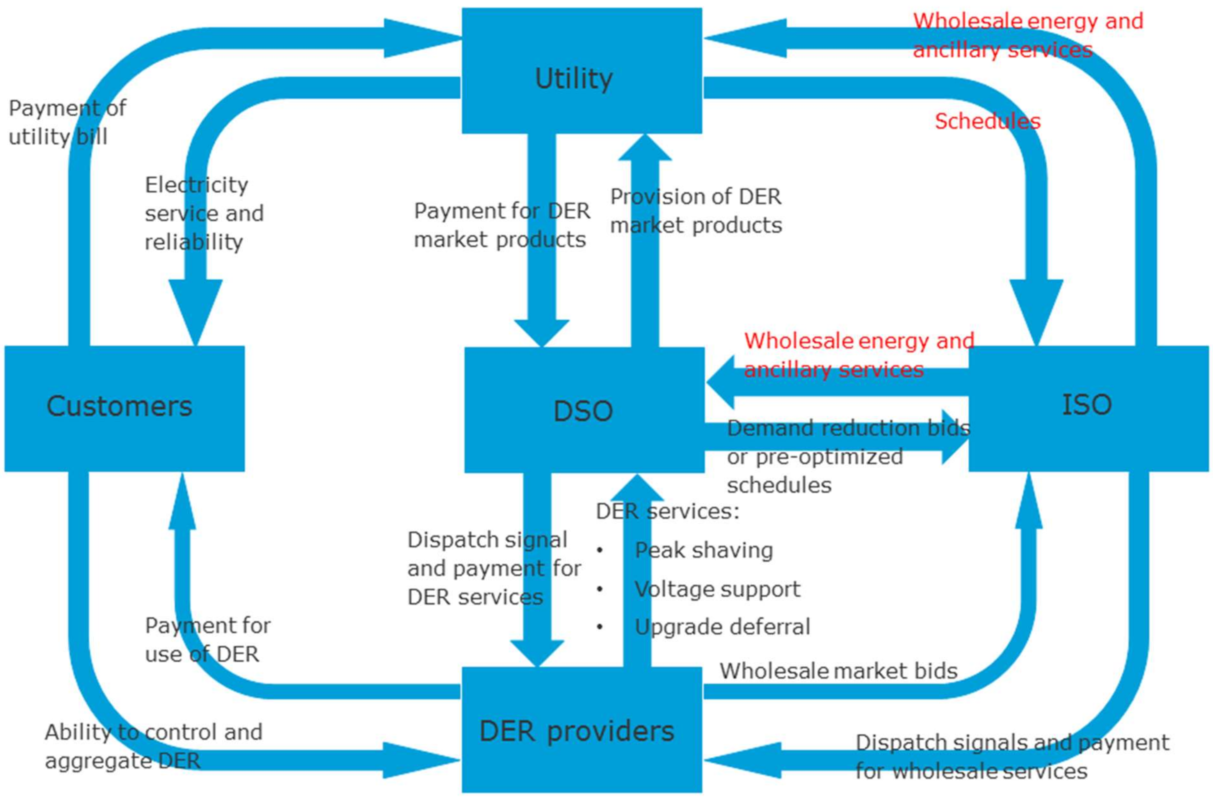

Figure B-2 DER Services Under a Distributed System Operator (DSO) Model

DSO market products and services

There is a wide array of market products and services that DER can provide, and the list will likely continue to increase as both controls and equipment technology advances. Rather than pre-define products to be traded in the DSO markets, NY REV, for example, takes the approach of allowing DER providers to define their own services and bid them into the markets. A similar approach is taken for the California DRP RFO process where, rather than specifying the desired service or technology, the need is defined such that a variety of technology solutions may be proposed. If the market product is sufficiently valuable, the DSO will procure it at greater volumes, other providers will enter the market, and competition will put downward pressure on prices. A non-comprehensive list of DER products that could be bought and sold in a DSO market is provided below, as adapted from reference material [2] and DNV GL experience.

Market products that the DSO would likely procure include:

- Base load modification/over-generation mitigation for local areas;
- Peak load reduction for local areas;
- Non-bulk ancillary services such as distribution-level voltage support, transient power; quality, and line loss reduction

- Bulk ancillary services for aggregation and bidding into the wholesale market;[72]
- Contingency services (reserved for emergency situations); and
- Transmission & Distribution (T&D) upgrade deferral.

Market products that would be sold on the DSO platform would likely include:

- Enhanced resiliency and emergency operational service;
- DER interconnection services;
- Smart technology, smart metering, and load management tools;
- Locational services: DSO determines optimal DER locations and solicits DER solutions from third parties (and potentially the utility);
- Pricing and billing services, including billing for DER aggregators and dynamic pricing;
- DER services such as sale of technology and maintenance contracts;
- Data and information services such as real-time customer usage data for in-home energy management and aggregated market data to inform market participants' decision-making;
- "Park and loan" energy storage services, where energy that cannot be delivered; and immediately can be stored for scheduled delivery at another time.

There are distinct differences in the types of product and services that would be bought or sold, with little overlap. However, if one DSO were to develop expertise in a specific procurement area, then the expertise in those procurement services could also likely be sold to other DSOs.

2.2 Roles of DSO, ISO, and Utilities

There are two key questions regarding DSO governance structure: the first is regarding the DSO's role with respect to the ISO, and the second is regarding its role with respect to the utilities. The DSO could be incorporated with the ISO, with the single entity dispatching the system down to the DER level, or the DSO could function as a separate organization that provides services similar to the ISO but at the distribution level. The role of DSO may be assumed by the incumbent utilities, or the DSO may be established as an independent organization. These contrasting governance structures are further defined, and arguments for and against them summarized, in the remainder of this section.

2.2.1 Delineating the role of DSO versus ISO

The role of the DSO in managing the distribution system is similar to the role that CAISO serves for the bulk market. A significant difference is that the DSO under most scenarios would typically not be a single statewide entity, but rather multiple entities serving a region, local distribution area (LDA), or transmission-distribution interface (T-D interface), or some combination of these. As such, to illustrate the possible DSO configurations and roles for a high penetration DER scenario, several DSO models from the LBNL/Caltech paper and slide deck [4] are discussed in detail below:

- **The "Total TSO Model":** Under this model, there is no DSO because all DSO functions would be performed by the TSO with DER monitoring and control extending into the distribution circuit.
- **The "Minimal DSO Model":** For this model, the DSO would be responsible for the physical coordination of all DER activities, and a key feature is that the T-D interface would be the information and coordination point with the TSO.
- **The "Market DSO Model":** This model is a simplification of the "Total TSO model" in that to participate in the market, DERs must be aggregated to a minimum size. This model is actually comprised of two scenarios because the DSO can serve as either 1) a coordinator for multiple DER aggregators, or 2) an aggregator itself. For both scenarios, a single resource is provided at each T&D interface to the TSO.

Key features and characteristics of each of the models are summarized below.

The "Total TSO Model"

Under this model, the DSO would have little or no role in distribution-level market services because monitoring, dispatching, and controlling would all be done at the TSO (CAISO) level. DERs down to a relatively small size would be fully integrated and dispatched by the TSO. DERs would be represented at their actual locations and the TSO's control would extend to the distribution circuit. Of all the scenarios that can be imagined, this it is the least feasible due to the significant technical and regulatory challenges. First and foremost, the technical challenge of installing monitoring and controlling equipment on a significant portion of the smaller DER systems, and then dispatching both T&D assets in response to the distribution systems, would likely be complex and more susceptible to smaller disturbances. On the regulatory side, it would require cooperation between FERC and state regulators, which could be a challenge. Because the TSO/ISO wholesale markets are under federal jurisdiction, while the retail, local distribution systems are under state jurisdiction, an unprecedented amount of coordination would be required. In addition, control by the TSO/ISO might tend to favor large, central solutions for economic (participant fees, transmission access charges, etc.) and historic reasons, although they would likely not be able to ignore the organic growth of DERs.

The "Minimal DSO Model"

This model differs from the Total TSO model in that control and visibility to the distribution system ends at the T-D interface, which is also where it is begins for the DSO. From the TSO perspective, for dispatch purposes the DERs are assumed to be at the T-D interface, rather than modeling the distribution circuits and physical locations of the DERs. The DSO would be responsible for the physical coordination of all DER activities, especially those that impact the distribution system or require response to TSO dispatches. The DSO would provide distribution services including interconnection to the distribution system and coordinating wholesale market participation. The DSO could also end up sourcing distribution grid services from the same wholesale market-participant DERs as under the TSO model. An important requirement of this model is that the DSO will need to have real-time communication and operating procedures with the TSO, as well as with the DER providers in the DSO's LDA, to ensure reliable operation of the distribution system. Because the TSO will not have visibility beyond the T-D interface, it will not know how its dispatched of DER are affecting the distribution system conditions. In that case, it would be up to the DSO to monitor, manage, and respond accordingly to the conditions.

The "Market DSO Model"

This model is a simplification of the Total TSO model in that, to participate in the market, DERs must be aggregated to a minimum size. For example, a minimum requirement of 10 MW could be required for participation in the economic dispatch or wholesale market. This model is actually two sub-models because it includes two scenarios. The DSO can serve as either: 1) a coordinator for multiple DER aggregators, or 2) an aggregator itself. For both scenarios, as with the Minimal DSO model, a single resource is provided at each T-D interface to the TSO. For both cases, it would be the DSO's responsibility to coordinate the responses of the DER aggregators and/or the individual DERs.

For the first sub-model scenario, the "DSO as coordinator of DER aggregators", the coordination function is complicated by multiple aggregators on the same LDA. Each aggregator would be independently submitting bids to and responding to dispatches from the wholesale market, which would all need to be coordinated by the DSO.

For the second sub-model scenario, the "DSO as aggregator of DERs", the DSO role is simpler. Under this scenario, the DSO's role for the distribution system is analogous to the role of the ISO for the transmission system. The DSO would also serve as the scheduling coordinator for the TSO market and, upon receiving a TSO dispatch, would decide which local DERs could best respond to the need. In this case "best" would imply most economically and without having a detrimental impact on the distribution system. The DSO would also balance the LDA supply-demand by importing or exporting as needed across the T&D substation. This model is the simplest model in regard to the interactions and coordination required between the DSO, TSO and DERs for a given LDA. However, it does not allow DERs to participate directly in the wholesale spot market, so the process would need to be very transparent to ensure regulatory non-discrimination requirements are satisfied.

2.2.2 Delineating the role of DSO versus utilities

Key challenges in defining the governance structure of the DSO include avoidance of too much market power, appropriate accountability for distribution grid reliability, and integration with existing governance structures. NY REV, for example, has designated utilities to serve as the DSOs (or Distribution Service Platforms—DSPs—in REV terminology). Other experts, notably John Wellinghoff, the former chairmen of the Federal Energy Regulatory Commission (FERC), argues that despite the advantages of utilities serving as DSOs, only a DSO that is completely independent from the utility can guard adequately against market power and ensure economic efficiency. DNV GL's references [4] contain a full discussion of the appropriateness of different DSO governance structures given the stage of industry evolution and the prevailing market or utility structure (i.e. vertically integrated or wholly or partially deregulated).

Arguments in favor of incumbent utilities as DSOs include:

- **Close connection between utility and DSO operations.** The system planning and operations responsibilities of the DSO are the responsibility of the utilities under the current model, such that an independent DSO could result in extra cost and organizational redundancy.
- **Streamlining of DSO creation and regulation.** Incumbent utilities serving as DSOs could initially be regulated under the current framework; the regulatory status of a new, independent entity would need to be determined.

- **Utilities are well positioned to facilitate immediate DER growth.** Utilities' incumbent knowledge of their own distribution systems and in-house expertise on resource planning, operations, and customer engagement would be assets in launching a transition to a DSO model. Economies of scale in utility DER investment could aid initial market development. They are also most aware of the portions of their distribution systems that are experiencing problems and can predict what portions may be an issue in the near future (via requests for interconnections, etc.).
- **An independent DSO may not entirely mitigate market power.** A utility that was motivated to exercise market power could potentially still do so through preferential operation of the distribution system, data manipulation, or influencing the DER market through its investment decisions.
- **Utilities could serve as DSOs initially, before a transition to an independent DSO.** The utility's performance as DSO would be periodically evaluated, and as DSO markets and operations become more established, it may be pertinent to transition to an independent DSO model. However, establishing an independent DSO from the outset could save costs relative to transitioning from a utility DSO.

Arguments in favor of independent DSOs include:

- **Smoother state-wide coordination and standardization.** Incumbent utilities serving as DSOs would create a patchwork that could encumber the establishment of uniform market practices across the state.
- **Avoidance of market power.** Utilities' monopoly status would create the opportunity to exert undue influence in a DSO market, resulting from the utilities' commercial interest in DER and customer load management combined with its control over access to the distribution network and dispatch of DER. A utility serving as DSO may see a financial incentive to maintain barriers to DER market penetration, such as inadequate data provision, tariffs that do not fully value DER, and cumbersome interconnection requirements.
- **Potential for less status-quo bias and greater promotion of innovation.** Under an independent DSO and market-based DER system, ideally there would be an emphasis on the best cost, most reliable and safe product or service to meet the distribution or transmission system need, rather than first choosing the most readily available utility-owned resource. Emphasizing the actual system need versus a specific technology or service should also promote innovation.

Utilities functioning as DSOs raise the question of whether they should be permitted to own DERs. Prohibiting utilities from owning DERs would mitigate concerns about market domination. However, even in a market environment, utility ownership of DER may be beneficial under certain circumstances. Utility-owned DER co-located with distribution system assets may be a cost-effective way to support system reliability, for example. In these circumstances, which would likely need regulatory approval, utility procurement of the DER would follow an RFO process.

Jon Wellinghoff has consistently advocated for an independent DSO model. For example, in comments to the New York Department of Public Service [4], Wellinghoff and co-authors state that "[j]ust as traditional management of the grid by vertically integrated utilities was inadequate to support the changing needs of the transmission grid, we posit that management of the New York distribution system by utilities alone will not be sufficient to sustain a resilient, clean, least cost, and innovative grid." The conflict of interest inherent in the utilities owning and controlling access to the distribution system, they argue, is too great to enable efficient DER deployment.

If the utilities continue to own the distribution infrastructure and are separate from an independent DSO, there is a question as to whether the utilities should be responsible for distribution engineering analysis, DER interconnection studies and procedures, DER hosting capacity analysis, distribution grid design, and switching/outage restoration and distribution maintenance. One concern is that the utilities' planning functions will be biased in favor of their own rate-based investments in distribution assets. This may be mitigated if the utility performs these functions as part of a larger planning process for which another entity (the DSO or TSO) is primarily responsible. Likewise, non-discrimination concerns exist regarding operational functions may be mitigated by expanding existing regulatory mechanisms [4].

2.3 Coordination with ISO and interaction with wholesale market

One of the primary roles of the DSO will likely be to coordinate the interface between the transmission and distribution systems, and to ensure that a DER that is committed to providing transmission-level services and can deliver those services through the distribution system. This includes ensuring that a DER does not have conflicting commitments to provide both transmission-level and distribution-level services. The DSO will need to coordinate the operational, though not necessarily financial, aspects of transactions between distribution-level actors (e.g. DER aggregators, municipal utilities) and the bulk system [5].

A DER that is operated to shave load peaks for distribution system upgrade deferral will reduce bulk-system costs as well. Lower peak load in the wholesale market will result in lower utilization of less-efficient peaking units (primarily gas plants), lowering costs and improving air quality, and eventually avoiding construction of such units entirely. Further, peak-shaving at the distribution level will reduce transmission congestion into high-load areas, potentially avoiding construction of additional costly transmission capacity. These benefits depend on visibility and controllability of DER, which a DSO market would help incentivize. On the other hand, DER that is not dispatchable and transparent at the bulk system level would increase uncertainty at all time scales in ISO planning, from operations to investments, contributing to increased system costs.

Considerations in the relationship between the DSO and ISO include:

- Ensuring that DER providers are compensated according to the benefits they furnish to both the distribution system and bulk system. One way to accomplish this would be for DSOs to aggregate the activity of DER for bids into the wholesale market.
- Evaluate potential conflicts between ISO/DSO dispatch instructions.
- The potential for unforeseen consequences to ISO day-ahead and real-time processes. In planning DER integration into wholesale markets, attention must be paid to avoiding any potential unforeseen consequences at the wholesale level that could degrade system reliability or contribute to operational uncertainty.

Further, there are issues that must be addressed regarding the prioritization of dispatch instructions from the ISO and DSO:

- If DSO's are self-balancing, can they either reduce their flexibility needs from the ISO to zero, or provide flexibility services up to the ISO?

- Can distribution deferrals be reliable on the presence of potential conflicting dispatch instructions from the ISO?
- The limits of the DSO's responsibilities would need to be clearly specified and detailed.
- Which services could be market-based would need to be clearly identified, specifically, which could be supplied by DER.

2.3.1 Long-term impacts of DRP proceedings on bulk system balancing

Under the Distribution Resource Plan (DRP) guidance ruling, utilities are responsible for the distribution system planning functions, but increased transparency in the planning process is necessary, via such modes as stakeholder review and regulatory oversight. As noted in DNV GL's references, "[t]his oversight extends to the authorization of subsequent decisions regarding the use of DERs as alternatives to utility investment through rate cases and other rate-setting proceedings." [4]

DERs could provide flexibility and reliability services to the grid, reduce ancillary service needs, and meet dynamic reserve requirements. The DRP process would need to investigate and determine if an independent DSO is needed to ensure the planning process is transparent. In this role, the DRP could have a significant long-term impact on the investigation and assessment of the feasibility for a DSO model to work in California. However, given that the regulatory environment generally moves more slowly than market developments, especially regarding the deployment of DERs and the DSO model, it will be an on-going challenge for the DRP to evolve and keep up.

2.3.2 Short-term considerations for system balancing

There are a number of critical short-term issues that should be considered and pursued to understand the potential of a DSO model that can successfully fulfill the system balancing function. These are noted below.

- **Demonstration projects:** Due to the complexity of operation, performing demonstration projects in a somewhat isolated environment or portion of the grid will be one of the best ways to evaluate and assess a DSO system. A microgrid environment could provide a good test-bed environment. Pilot projects such as the ones recently approved in New York are good examples of this method. In support of the NYISO DER Roadmap, three pilot projects involving front-of-the meter batteries, solar and +storage, and curtailable load configurations will be tested. Demonstrating the potential for these products to service both the retail and wholesale markets is a critical objective for these projects. (see Buffalo Niagara Medical Campus in Section 3).
- **Interconnection requirements:** Under a DSO model, the interconnection requirements will need to be updated to ensure reliable communication and control of the DERs. With high-penetration DERs, a major distribution system issue will be bi-directional power flow across the system, and DERs would be interconnected to allow dispatch or curtailments. As microgrids become more prevalent and capable of islanding, DSO operations will also need to coordinate micro-grid interconnections. In addition, there is the DSO-TSO interconnection via the T&D interface. The DSO will need to coordinate all of the interconnections, making the distribution system operation much more complex than it is now.
- **Monitor NY REV activities:** New York State's Reforming the Energy Vision (REV) initiative intends to implement a DSO model, with utilities initially fulfilling the role of DSO. Monitoring the progress of

NY REV would give CPUC insight into the feasibility, potential challenges, and any unforeseen costs, risks, or benefits of the DSO model. The information provided above on the recently approved NYISO DER pilot studies is a perfect example of this work.

2.4 Costs and benefits from a ratepayer perspective

Although the primary role of the DSO would be to optimize deployment of DERs while maintaining the reliability and safety of the distribution system, a major emphasis of California's Distributed Resources Plan (DRP) is to "minimize overall system cost and maximize ratepayer benefits from investments in preferred resources." A few of the benefits, costs, and other impacts from a ratepayer perspective to be considered under a DSO model are discussed below.

2.4.1 Benefits

Based on DNV GL's research and experience, potential benefits of the relationship between the DSO and ISO could ideally include:

- **Increased distribution grid reliability and resiliency.** Visible, dispatchable DER could align with the increased use of advanced distribution-level sensors and control devices to improve voltage regulation, fault detection, and outage recovery. Access to DSO market data could enable the utility to better incorporate DER activity into grid operations and planning, which could ideally increase grid reliability and resiliency. In contrast, continued organic growth in customer-owned, behind the meter systems without operational information and telemetry data for those systems, could decrease grid reliability and stability.
- **Reduced electricity prices.** Assuming the DSO model results in increased economic efficiency, electricity prices to consumers will decrease. This should be the result of the combined effect of reduced wholesale prices, primarily due to peak load reduction, efficient DER operations, and deferred distribution as well as potentially transmission network upgrades.
- **Protection against high network charges resulting from utility revenue erosion.** If DER deployment continues in the absence of a framework to actively integrate it, utility revenue may decrease to the point that utilities would have to raise rates significantly to maintain their existing levels of service and system responsibilities. This would likely have the most impact on low-income customers who are unable to afford DER.
- **Increased control over energy use and costs.** Ratepayers will be newly able to actively manage their energy consumption patterns and will have greater choice in the use of DERs to maximize their value, including providing grid services. Ideally, the market would incentivize consumer engagement through pricing mechanisms designed to nudge consumer choices into alignment with efficient operation of the distribution-level and bulk-level systems. Although DER customers would need to provide information and potentially control to the DSO, they could benefit from the increased telemetry and system control themselves both monetarily and more visibility into their system's performance.
- **Avoid NIMBY opposition to new transmission lines and power plants.** Increased penetration and efficient use of DERs could help avoid the need for construction of new transmission lines and large power plants, which often draws opposition from ratepayers in local

communities. Going further, ideally the DSO would be able to motivate the market to offer more DER options to meet ratepayer-customer needs while also improving grid reliability, safety, and operation.

- **Standardized DER products and services.** An independent DSO could potentially also facilitate the standardization of products, services, and costs, ensuring more consistent products that would make it easier for market participants to make comparisons. However, the amount of standardization would likely be limited as the needs for every circuit and service area are unique and would likely require some customization of most services and products.

2.4.2 Costs

Ratepayer costs are much more difficult to define because there are a multitude of complex and different costs and regulatory issues under both the current and DSO system, many more than can be discussed and detailed in this report. There are not just monetary costs, but also privacy and control costs. However, a few of the primary cost considerations are discussed below.

- **Start-up and infrastructure costs**. Regardless of the exact DSO model, it will take substantial investments to build out and characterize all of the key aspects of a DSO model, such as market and operation rules, economic models, control centers, monitoring, control and communication systems. Since no DSO has been implemented at scale, it is unknown how much the start-up costs would be to develop a DSO system.
- **Inequity of customer-owned/leased DER devices.** Customers may choose to purchase DERs outright. These are most typically solar (PV), batteries, and EVs. This transaction would entail an initial lump-sum cost followed by benefits that accrue over time and would favor higher-income customers who can afford the up-front investment. Other models, such as leasing DER equipment from a provider, could help make DERs available to more of the population. Utilities, regulatory bodies, and the DSO should consider how best to equitably serve low-income customers under a DSO model.
- **Program administrative costs.** Ratepayers would ultimately bear the administrative cost of implementing a DSO model, including the increased measurement and verification needs as well as improved metering and communications systems. However, ideally these increased costs would be offset by more realistic pricing of the DER production to reflect temporal and locational value, versus a more general time of use metering approach. Customers would also incur a non-monetary cost in the form of having to cede some privacy and control of their DER system to the DSO.
- **Reliability costs.** Some DERs do not have the reliability, flexibility, and certainty of a dispatchable, fossil-fueled power plant, so back-up/reserve costs incurred by the utility or DSO would be added to the ratepayer costs.
- **Valuation and compensation.** There is much debate around, and many regulatory issues related to how to accurately value and pay for DER services and products, especially for non-dispatchable technologies, and given the locational and temporal grid variations that are the result of DER penetration.

2.4.3 Other Challenges

Additional factors that could impact ratepayers and adoption of the DSO model include:

Uncertainty surrounding customer acceptance and participation. As previously mentioned, the monitoring and control role of the DSO would require the intrusive installation of metering and control devices on the customer's DER, and many customers may resist the intrusion. Furthermore, having to deal with yet another entity such as a DSO in addition to a DER provider and utility might be difficult to explain to the typical residential customer, and therefore serve as a barrier to acceptance.

Split incentives. DER services may be subject to the "landlord-tenant problem," in which a building owner may be reluctant to invest in DER, since only the tenants, who pay the electricity bills, would reap the benefits. DER pricing plans would need to address this scenario.

Reliability/Resiliency concerns. With climate change and every successive year getting warmer and fires burning more frequently and fiercely in California, reliability and resiliency will remain a critical issue for California utilities and ISO. In at least one area, market conditions created by greenhouse gas and renewable goals created conditions in which economic decisions were made to close two gas plants, but "must-run" orders were issued by CAISO to keep these uneconomic plants running to maintain system reliability. The addition of yet another entity such as a DSO might actually decrease reliability and resiliency by adding one more layer to the system.

Security/Hacking. Regardless of configuration for the DSO model, the data needed will require additional sensor-monitoring points. Every additional point could be another opportunity to hack into the grid's information and control systems. Utilities have very strict data security requirements placed on them by FERC, and any additional threat vectors will be very heavily scrutinized.

Utility business model. Under DSO models where capital investments could be shifted to third parties, it is unclear how utilities would continue to operate. The DSO would duplicate much of the utility's existing administration, and the utilities' role would be greatly diminished. If utilities were to administer the DSO, the utilities' business model would need to be shifted away from earning a profit on capital investments and be incentivized to operate an efficient DSO market.

Governance. It is unclear how a new, independent entity would be regulated if the DSO is not the regulated utilities. If ISO takes on more DER management activities, it is unclear how to delineate the roles of the local regulator versus FERC.

3 CASE STUDIES AND PROGRESS TOWARDS DSO MODELS

A review of global system operators and utilities shows that most are aware of the growing penetration of DERs, and their potential to impact the grid. DNV GL has not, however, found a jurisdiction where there is currently a competitive open DSO market for DERs to provide capacity or grid services. Domestically, to better integrate DERs, several jurisdictions, such as those within New York and California, are conducting pilot projects to assess the operational and commercial barriers for DERs to participate in the wholesale and distribution markets. The results of these pilots will start to become available in 2019.

In Europe, the concept of DERs providing bulk energy supply or flexibility is still in its infancy. Although there are virtual power plants that aggregate different DERs, the DERs primarily serve other commercial purposes. Even though some local administrators or incumbent vertically integrated utilities may use DERs to provide high levels of self-supply and independence, they do not control the DERs or have a market-based mechanism to procure services from them. The only simulation of a market-based DSO we found is a study conducted by DNV GL for the Swiss Federal Office of Energy that was considering procuring DERs services in a local flexibility market. Since the domestic pilot projects are very similar to the demonstrations that are already being conducted in California, the following summary focuses on the Switzerland study which is most resemble a market-based DSO model.

In the sections below, DNV GL has summarized several studies and pilot projects regarding the integration of DERs to provide energy or ancillary services for the grid. Key takeaways from these studies include:

- DERs can provide energy and grid services under the current market constructs: through utility RFP procurements or aggregated bids to the wholesale market. DERs participating in the wholesale market is a relatively new concept; however, there are pilot projects under way to demonstrate the cost-benefit and clarify market participation rules.
- DERs procured in an open DSO market can be a cost-effective solution for grid services under specific conditions and locations. As DER costs fall and technologies improve, the cost-effectiveness of DERs in comparison to traditional alternatives will continue to improve, and thus be effective in a competitive market model.
- Education on the cost-effectiveness of DERs providing grid services for utilities and continued funding of technology development are key features in a developing a DER market and aging grid.
- The regulatory and market frameworks needed to be overhauled to enable efficient DER participation in the wholesale and distribution market. These tend to be the key barriers for DERs to participate in the wholesale market and for DSO implementation.

3.1 Switzerland - Activation of Local Market DERs for Flexibility Services

In 2015, the Swiss Federal Office of Energy conducted a cost-benefit analysis of using a traffic light model in the Swiss electricity distribution grid. [8] The traffic light model, a novel concept first considered by Germany,[73] enables the use of DERs by distributed network operators[74] to alleviate local network congestion. In the traffic light model, the traffic light with "yellow" or "red" light would indicate potential congestion in a DSO network, e.g., voltages issues, or thermal readings on transformers in excess of rated limits. The purpose of the traffic light scheme is to avoid infrastructure investment to address these issues, by leveraging an alternative option to maintain grid stability.

During the yellow phases, the DSO contracts local or regional flexible resources in its own technology-neutral, competitive market platform (the flexibility market) to compensate for bottlenecks in the distribution grid. In the red phases, where it is no longer possible to resolve the bottlenecks by local flexible resources, the DSO intervenes with grid-stabilizing measures in the operation of the system markets.

A prerequisite for this concept is the implementation of suitably accurate and networked sensors in the distribution grids, to enable the DSO to assess the grid conditions. In addition, this concept raises several regulatory prerequisites that must be in place before implementation:

1. The expected size of the flexibility market (number of suppliers) must be sufficient to guarantee competition.
2. There must be a complete unbundling of grid operations and generation operations to avoid conflicts of interest of the DSO.
3. The traffic light model should be the most cost-effective, technical solution for the cost of bottleneck management.

This study focuses on addressing the cost-effectiveness pre-requisite (#3 above). The analysis benchmarks the costs and benefits of the traffic light model in two ways to ensure reliable operation of the grid: (1) conventional grid expansion, and (2) expansion with controllable local grid stations. The study conducted simulations of costs and benefits under different DER growth scenarios, network configurations (rural, semi-urban, urban), and smart grid technology setups and investments. For the traffic light model, it is assumed that a complete rollout with smart meters would have taken place by 2035, so that only the remaining IT and communications technology would be added to the traffic light model for cost aggregation.

DNV GL's simulation results show that there is a need for a traffic light model only after 2020, in a scenario with ambitious expansion of renewable energy. In rural distribution grids, which are characterized by comparatively low load and high decentralized feed-in energy from renewables, the traffic light model proves to be unsuitable: the traffic light changes between green and red phases as DERs respond to market price signals and stop producing when congestion happens. In fact, it has negative consequence because there is no marginal cost in PV generation. In the traffic light model, PV systems would not react at all if the prices are positive, and as soon as the critical price limit falls below, they would all switch off at the same time.

By contrast, the traffic light model can resolve bottleneck situations in urban distribution grids where there are high-load grid conditions and medium to high penetration of communications and IT technologies. With sufficient number of flexible loads, demand side management is more cost-effective under the traffic light model because demand is price sensitive. In addition, there are indirect benefits of the traffic light model because the information about grid status provided in the traffic light model is valuable to DSOs for other purposes.

From the regulatory perspective, these issues are observed:

- Bottlenecks tend to occur in the lower voltage levels due to the expansion of PV and wind; the distribution grid operator as a single buyer faces only a very limited number of potential providers of flexibility. If there are not enough providers, there is risk of collusion due to the proximity.
- The organization of a decentralized market for flexibility is another important point. The large number of distribution grid operators operating on low and medium voltage in Switzerland makes individual operation of a flexibility market seem cumbersome. On the other hand, the distribution grid operator is the only one who has grid-relevant data that needs to be communicated to the

market in near real-time. Accordingly, an interface of central flexible market operators and DSO would have to be administered.

- A traffic light model requires extensive unbundling of grid operation from the power supply. If this is not ensured, there could be disincentives for the distribution system operator to favor flexibilities from the connected supply area by intentionally causing yellow traffic light phases. Without strict firewalls, the coverage area could access proprietary information about the condition of the grid and the levels of other flexible resources available. Such extensive unbundling seems unlikely in the fragmented grid operator structure in Switzerland.
- From a regulatory standpoint, the question arises as to how it can be ensured that the flex market is the cost-effective alternative to congestion management. While the costs of building conventional grid, expansion are easily predictable and the price for procuring contracted system service is known, the scope and costs of the traffic light model is largely unknown. This is because the cost of the traffic light model would depend on the number of flexibility events, the supply of flexible resources and the ultimate market price for the flexibility services.

3.2 New York ISO DER Pilots

New York Independent System Operator will be conducting pilot projects to demonstrate DER capabilities and wholesale market integration. The pilots would help modify market design and improve operational coordination processes among different stakeholders. According to a press release from July 2018 [10], the DER aggregation project includes:

- Front-of-the-meter batteries to demonstrate coordination of multiple DERs to be effectively dispatched by the NYISO or Con Edison depending on system needs or conditions;
- Front-of-the-meter batteries co-located with solar to evaluate the ability of such aggregated resources to provide both wholesale and retail services, and
- High-rise buildings with curtailable (readily adjustable) energy load to evaluate the capability of building management systems to provide ancillary services.

The current market rules do not support these types of projects, so the demonstration testing will be performed in an environment separate from NYISO's production market. The demonstration testing is expected to begin in the first half of 2019.

3.3 New York Virtual Power Plant Pilot Program

In New York, Con Edison developed a Virtual Power Plant pilot program along with SunPower and Sunverge Energy. This project is designed to demonstrate how aggregated fleets of solar and energy storage assets in hundreds of residential dwellings can collectively provide network benefits to the grid, resiliency services to customers, monetization value to Con Edison, and results that will inform future rate design and development of distribution-level markets. At this time, the pilot has encountered delays due to permitting issues with Fire Department of New York (FDNY). Project costs and benefits are not yet available.

3.4 NY REV – Buffalo Niagara Medical Campus DSP Test-bed

New York's Reforming the Energy Vision program, or REV, is a comprehensive energy strategy for New York State. REV is intended to, in part, develop new energy products and services to protect the environment. One of REV's demonstration projects, which was approved as of June 2016, is being conducted at the Buffalo Niagara Medical Campus (BNMC). This project, with a team comprising National Grid, BNMC, and Opus One (a software engineering company), is intended to develop, deploy, and test a new distribution-level energy market solution. As noted in National Grid's filing [9], the purpose of this project is to develop and test solutions based on a local, small-scale, but centralized DSP that would communicate with network-connected points of control (POC) associated with BNMC DERs. The POC would be hosted on a server at a customer's site with communications capabilities to control DER assets based on events on the electric power system and contractual agreements in place with the local DSP provider.

The proposed local DSP would communicate the electric distribution system needs of the local substation and feeders and send dynamic pricing signals to the POCs. The POCs would communicate with the DSP as to the availability of BNMC DERs to respond to local electric system needs and the willingness to accept pricing signals. Within the "market" of the BNMC, the Project will evaluate what price signals and/or other revenue opportunities motivate BNMC member institutions with DER capabilities to provide the DSP with local electric distribution system services at the POC level, and what revenue opportunities would encourage additional DER investment. Based on the most recent quarterly report available online (Q1 2018) the project has achieved the following milestones: technology development, design, DSP user acceptance testing, POC user acceptance testing, and proof of concept go-live, among others. The project is scheduled to complete in Q2 2019.

3.5 LADWP DERIS Study

The Los Angeles Department of Water and Power (LADWP) examined an approach-model in their Distributed Energy Resource Integration Study (DERIS) [4]. This scenario assumed a fully-managed DER portfolio with centralized control of the process (management, planning, deployment, etc.). The study used the key characteristics of LADWP's system to create an optimal DER portfolio, with the key goal to produce an economic benefit to the ratepayers. Results of the study are shown graphically in Figure B-3, which illustrates a much smoother shape for the "managed DER" scenario on the right, in comparison with the "unmanaged DER" scenario on the left. To reach the high level of DER penetration, the scenario assumes that customer incentives would be offered, and that special tariffs would incentivize customers to allow their DER systems to be managed by LADWP. Additionally, implementing this scenario would require large investments in distribution system management systems, DER management systems, and SCADA systems to gather the data necessary for monitoring and management.

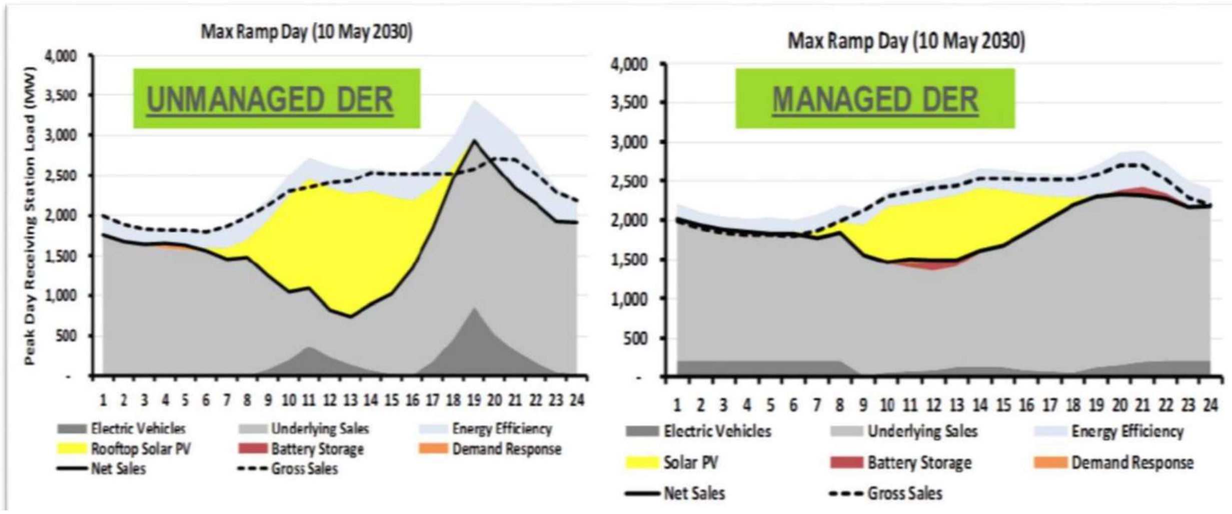

Figure B- 3 Example of Fully Managed DER Simulation for LADWP

To achieve this, LADWP is considering three business models for implementing DER aggregation in the LADWP service territory. The three models considered were:

1. LADWP acting as DER aggregator and provides energy, capacity, and/or distribution deferral services through coordination and control of the DER aggregation for the benefit of its ratepayers.
2. A third-party act as aggregator and offers services through a competitive solicitation to LADWP. This report describes how a competitive solicitation might be structured to ensure that the risk of engaging with a third-party is minimized.
3. Hybrid model where a third-party aggregator presents the value proposition to the customer, may own the customer-side equipment, managed installation and customer services. The distribution system monitoring, billing and other responsibilities related to customer compensation continue to be managed by LADWP

LADWP is currently studying the cost-benefit of these options, as well as the potential for lower penetration scenarios. The results will impact LADWP's implementation and resource plans.

3.6 ARPA-E NODES

the Advanced Research Projects Agency-Energy (ARPA-E), is a segment of the United States Department of Energy which aims to provide funding for "high-potential, high-impact energy technologies that are too early for private-sector investment" with the goal of "radically improving US economic prosperity, national security, and environmental well-being" through energy research projects. The ARPA-E NODES, or Network Optimized Distributed Energy Systems, Program is working to enable renewable penetration at the 50% level or greater by developing transformational grid control methods that optimize use of flexible load and DER.

Twelve different projects are currently funded in this program; DNV GL itself is supporting one program titled "Enabling the Internet of Energy through Network Optimized Distributed Energy Resources." It is in its second year of work on this project, which is focused on the development and testing of the Internet of Energy (IoEn) platform for the automated scheduling, aggregating, dispatching, and performance validating of network optimized DERs and controllable load. The IoEn platform is intended to simultaneously manage both system level regulation and distribution level support functions to facilitate large-scale integration of distributed generation onto the grid. The platform is intended to demonstrate the ability of customer-sited DERs to provide grid frequency regulation and distribution reliability functions with minimal impact to their local behind-the-meter demand management applications. The IoEn will be demonstrated and tested at Group NIRE's utility-connected microgrid test facility in Lubbock, Texas, where it will be integrated with local utility monitoring, control and data acquisition systems. By increasing the number of local devices able to connect and contribute to the IoEn, this project aims to enable to increase of renewables penetration which maintaining high levels of grid performance.

4 CONCLUSIONS

As stated in the Introduction, the intent of this paper is not to advocate for adoption of a Distribution System Operator (DSO) model or independent DSO, it is instead to describe the concept, contrast it against the current utility-drive RFO system, and to use several model examples and the associated discussion to illustrate the concept, and look at how a market-based DSO construct might work and what capabilities would be necessary. The DSO is one of many prominent ideas currently being discussed, explored, and tested in California and other jurisdictions to address the increased penetration of DERs and their impact on all aspects of the T&D grids. The concept of a market driven DER DSO is an extraordinarily complex, continually evolving, and multi-disciplinary model that is still being explored and developed as the electricity markets continue their organic evolution to incorporate DERs. There are still many uncertainties related to DSO models, especially related to their costs, benefits and technology capabilities. Demonstrations projects are being conducted in small scale or isolated environment to assist with understanding some of these questions; so far, these projects are yielding mixed results. The DSO concept has never been deployed at scale. As regulators consider DSO models, the complex elements of the DSO model may be better addressed within the existing framework of workshops, pilot projects, and research efforts associated with the Customer Choice Project, Grid Modernization technology planning, the EPIC program, and/or other CPUC or CEC programs. Although the goal and purpose of a market-based DER DSO model would be to ensure optimized and efficient distributed resources planning, distribution market operations, and distribution market opportunities for DERs, the primary purpose of any investment in the electricity system must be a focus on its ability to provide safe, reliable, affordable, and clean electricity.

Additional issues and recommendations to be considered for future research efforts include:

- The electricity market will continue to evolve towards decarbonization, electrification, and incorporation of the menagerie of DERs. Change will not come overnight, and the smaller-scale (T-D interface, feeder line, etc.) incremental changes offer great opportunities for pilot studies and lessons learned that can be applied to smart evolution of the larger ecosystem and active load shape management. There are still many uncertainties related to the DSO concept. The CPUC should continue demonstration projects to assess the value of DERs on a locational and time of day basis. This would contribute to evaluating the cost and benefits of a DSO model. Pilot projects can also be devised to test out potential operational and market rules, and how the technologies can meet these requirements.

- In addition to administration and regulation, valuation, especially temporal and locational, and compensation for DER-based resources are important issue. The capacity of DERs to forego or delay upgrades to over-loaded transmission or distribution lines is an essential part of the valuation.
- Because the DSO concept is developing so quickly, a more detailed report on this research effort would be better suited as a monthly or quarterly newsletter versus a static report.
- The definition of DERs is also an issue. DERs are a true menagerie of options and configurations, so it may not be sufficient to discuss the whole basket of DERs but instead break these down further into groups by technology, capability, location, size, etc. for further discussions about their integration.
- The taxonomy used to discuss DERs and DSOs is evolving on a daily basis. Creating an authoritative list of definitions, terms, concepts, and configurations as used for California applications could help ensure consistency in discussions and could help focus the system evolution.
- A variety of system modeling efforts are underway that would allow more detailed system cost and impact assessments to be performed. These efforts should be catalogued and monitored to identify tools that can be used to better assess concepts like the DSO model. CPUC should continue to monitor DER pilot projects in other jurisdictions and study their lessons learned.
- It is important to consider role of utilities in a DSO model to ensure a sustainable business model for utilities that are obligated to serve.

5 WORKS CITED

[1] State of New York Public Service Commission, "CASE 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.Order Adopting a Ratemaking and Utility Revenue Model Policy Framework.," 2016.

[2] Reforming the Energy Vision (REV) Working Group 1: DSPP Markets, "Staff Report on the work of the DSPP Markets Committee," 2014.

[3] P. De Martini, L. Kristov and L. Schwartz, "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation, and Oversight," Lawrence Berkeley National Laboratory, 2015.

[4] J. Wellinghoff, K. Hamilton and J. Cramer, *Comments on Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Case No. 14-M-0101,* 2014.

[5] L. Kristov and P. De Martini, *21st Century Electric Distribution System Operations,* 2014.

[6] DNV GL, "Cost-benefit Analysis of a Traffic Light Model Solution for the Electricty Market of Switzerland," Swiss Federal Office of Energy (BFE), Ittigen, Switzerland, 2015.

[7] New York Independent System Operator, "NYISO Announces Distributed Energy Resource Pilot Projects," 26 7 2018. [Online]. Available: https://home.nyiso.com/press/press-release-nyiso-announces-distributed-energy-resource-pilot-projects/. [Accessed 3 8 2018].

[8] National Grid, "REV - Demonstration Projects - BNMC DSP Engagement Tool," 17 June 2016. [Online]. Available: www.dps.ny.gov/REVDemos.

[9] D. Erickson, "Market Architectures for Managing Distributed Energy Resources," E3R Consulting, Philadelphia, 2018.

[10] State of New York Department of Public Service, "Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Developing the REV market in New York: DPS staff straw proposal on Track One issues," 2014.

[11] F. Rahimi and S. Mokhtari, "A New Distribution System Operator Construct," Open Access Technology International, Inc., Minneapolis, MN, 2014.

About DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 14,000 professionals are dedicated to helping our customers make the world safer, smarter, and greener.

APPENDIX C

Appendix C
List of New and Outstanding Issues

A. Distributed Energy Resources (DERs) are being deployed in large numbers without sufficient planning to fully integrate them with grid operations. Unstructured DER growth increases grid volatility, which results in the need for more extensive grid upgrades.

B. Electric vehicles and chargers will have a major impact on the electric grid.

C. Environmental and Social Justice (ESJ) communities as defined in the CPUC's ESJ Action Plan do not have equal access to DERs, which impacts rate equity.

D. Distribution planning processes do not sufficiently: (a) engage the communities where grid infrastructure would be installed; or (b) gather feedback about local development and DER siting plans to adequately forecast grid needs.

E. Investor Owned Utilities (IOUs) have insufficient incentive to support DER deployment.

F. Distribution planning under the Distribution Resources Plans (DRP) proceeding (R.14-08-013) is narrowly focused on capturing distribution deferral value via the Distribution Investment Deferral Framework.

G. DER value streams remain untapped (e.g., energy and ancillary services, greenhouse gas costs/credits, and resiliency).

H. As grid defection becomes more cost effective, it could become more common, which would increase costs for those that remain connected.

I. The IOUs are not yet capable of dispatching aggregators or individual, behind-the-meter DERs to provide grid services using smart inverter advanced functionality except on a limited, pilot-level basis.

J. IOU Grid Modernization Plans may be inadequate to facilitate widespread DER integration.

K. IOU General Rate Cases do not include the same level of cost detail for planned investments included in annual DIDF filings. The two filing processes are not sufficiently aligned.

L. DRP Data Portal data need to be validated and the hosted tools and scope of data updated to make them sufficiently useful to support DER provider and community planner needs.

APPENDIX D

Appendix D

DRP Retrospective Notes

January 2020

DRP Retrospective Workshop Notes
1/08/2020

On January 8, 2020 Gridworks convened key stakeholders in California's Distribution Resource Planning initiative to develop focused recommendations on whether and how to move forward with Distribution Resource Planning in California. Meeting participants (listed below) engaged in a facilitated conversation to develop the following recommendations. Not all participants endorsed all recommendations.

What have been the key successes of DRP that need to be nurtured? What's the best way to do so?

- The DRP has successfully provided California a compelling vision for the future of the distribution grid and DER. To nurture that vision, it should be updated to consider how the insights and tools emerging from DRP should be used to support new state priorities (e.g., resilience, electrification).

- The Integration Capacity Analysis has been a success. To complete and further its utility:
    - The results should be validated;
    - The results should be technologically neutral;
    - The tool should be deployed to better support interconnection, as developed by the Rule 21 WG2.

- Increased data access from the various DRP tools and reports is a success. Data currently publicly available should remain so.
    - The value of the transparency made possible by through make public key data would increase if there were more applications.

- Linking the results of the DRP to the sourcing efforts of the IDER has been a success. This link should be strengthened and maintained.

- The DRP has successfully maintained a focus on value, working to identify which DER save money and which ones do not. This focus should be nurtured.

What priorities do participants have for DRP going forward and what is the best way to pursue them?

- Storage has been the most successful technology furthered by DRP. Going forward, successful integration of EE, DR and diverse portfolios would provide further value.

- A stronger connection between the insights of the Grid Needs Assessment and funding requests in the GRC would provide value.

- A gap persists in the 1-3 year horizon for DER sourcing to provide distribution deferral. Closing this gap through new sourcing mechanisms or technological solutions may provide additional value.

- Critical thought is needed on how DRP applies to emerging grid resilience priorities.

- The various ongoing pilots and demonstrations should be concluded and the results should be organized into actionable takeaways. Emphasis was placed on the IDER Incentives pilot.

- The processes and proceedings used to nurture DRP successes and support new priorities should reduce regulatory burden for participating parties. One solution may be to determine new procedural homes for priorities identified here, while closing the DRP proceeding itself.

Participants:

- Peter Klauer (CAISO)
- Rob Peterson (CPUC)
- Josh Honeycutt (CPUC)
- Tim Drew (Pub Adv., CPUC)
- Steve Schumacher (Pub Adv., CPUC)
- Rene Podho (Pub Adv.,CPUC)
- Jaime Fein (EDF)
- Gabe Petlin (Energy Division)
- Simon Baker (Energy Division)
- Mike Florio (Gridworks)
- Matthew Tisdale (Gridworks)
- Tony Brunello (Gridworks)
- Hector Tavera (Gridworks)

GRIDWORKS

- Mac Roche (Gridworks)
- Patrick Donaldson (Horizon water Development)
- Sky Stanfield (IREC)
- Samuel Saddik (PG&E)
- Bill Peter (PG&E)
- Lisa Wan (PG&E)
- Tyson Lagerbauer (SCE)
- Diana Gallegos (SCE)
- Fernando (SDG&E)
- Alan Dulgeroff (SDG&E)
- Michael Norbeck (Sunrun)
- Audrey Le (Sunrun)
- Lorenzo Kristov (Independent consultant)