Pacific Northwest NATIONAL LABORATORY

PNNL-35204

Distribution Hosting Capacity Auction Design

Marginal Distribution Capacity Pricing Mechanism for Efficient Investment and Cost Allocation

October 2023

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

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Acronyms and Abbreviations

CAISO	California Independent System Operator
DER	Distributed Energy Resource
DR	Demand Response
DSO	Distribution System Operator
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
HVAC	Heating, Ventilation, and Air Conditioning
ISO	Independent System Operator
ISO-NE	ISO New England, Inc.
kV	Kilovolt
kVA	Kilovolt-ampere
kVAr	Kilovolt-ampere reactive
kW	Kilowatt
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operator
NYISO	New York System Operator
PJM	PJM Interconnection
PV	Photovoltaic
SPP	Southwest Power Pool
SVC	Static Var Compensator

Abstract

As electricity markets begin to shift from reliance on large, centralized power plants and towards distributed energy resources (DERs), there is a growing acknowledgement that more efficient planning, operations, and oversight is needed in the distribution system. This paper addresses one step in that direction by proposing an auction mechanism that uses a detailed distribution system planning model that allocates permits to end-used customers who request hosting capacity to install new devices at their location and network upgrade contracts to utilities or 3rd-party contractors who offer to upgrade system components. The resulting plan maximizes market surplus, defined as the maximization of the total benefit to consumers minus the cost of network upgrades. We apply a marginal pricing scheme to the auction's results such that the cost of each permit or contract is differentiated by time and location, based on the Lagrange multipliers of binding network constraints. These prices are shown to be no greater than the bid price of any awarded permit and no less than the offered cost of any awarded upgrade contract. Furthermore, the nonlinearity of power flows in the planning model results in an additional surplus that would be collected by the entity that hosts the auction, which could then be refunded to market participants or used to cover overhead costs of running the market. We provide four example auction results in a simple three-node distribution feeder to demonstrate the properties of the design. Results suggest that larger or more realistic case studies could be a promising next step.

1.0 Introduction

Many regional electricity market operators have developed capacity markets to help ensure reliable and secure electricity supply by incentivizing the availability of sufficient electricity generation capacity to meet peak demand. When resources cannot recover their fixed costs (e.g., investment, operations, and maintenance) through energy market revenue, capacity markets can provide supplementary revenue to ensure that there are sufficient supply resources to maintain system reliability. In short, capacity markets seek to ensure that the system maintains resource adequacy – enough supply resources to be able to serve at least the forecast peak demand plus a reserve margin.

Capacity markets could provide an important role in supporting expected growth in customer-owned distributed energy resources (DERs). DERs can include many resource types, such as rooftop solar photovoltaics (PV), energy storage from electric vehicles (EVs), and demand response (DR). In general, DERs differ from conventional generation resources in a number of ways:

- They are located on the low voltage distribution system, or possibly behind an energy consumer's usage meter.
- Individual DERs are small, measured in kW rather than MW.
- DERs may participate either in retail energy markets (e.g., through net energy metering programs), through wholesale markets (through DER aggregators), or, in some cases, both.

To date, there are few centralized mechanisms to efficiently coordinate DER investments in a centralized manner to a similar degree as is currently performed in the bulk transmission grid. Properly valued and coordinated resources can address a range of challenges on the distribution system, including local peak usage reduction, voltage regulation, and other ancillary services. Unlike conventional capacity markets that operate at the wholesale level and deal with large-scale generation capacity, a distribution hosting capacity auction could target localized distribution networks and address the challenges of managing electricity supply and demand at the distribution level. This could be accomplished by an organization such as various Distribution System Operator (DSO) proposals, a distribution utility, or by some third party that is given planning authority of a local distribution system (Hammerstrom et al., 2008; Hammerstrom et al., 2009).

The key goals of a distribution hosting capacity auction include:

- Distribution Grid Reliability: Ensuring the reliability and stability of electricity supply at the distribution level, especially during periods of peak demand.
- Grid Congestion Management: Identifying the least costly infrastructure upgrades that are able to maintain reliable distribution system operations by managing appropriate voltage and power flow.
- Demand-Side Participation and Flexibility: Encouraging consumer participation in electricity markets through flexible DERs like rooftop PV panels, battery storage, EV charging, and DR programs that provide additional capacity and support to the grid.
- Grid Decarbonization: Promoting the integration of decentralized and clean energy resources into the grid, thereby supporting sustainability and reducing carbon emissions.

- Enhancing Grid Resilience: Strengthening the resilience of the distribution grid against potential disruptions or contingencies by leveraging the capabilities of DERs.
- Resource Portfolio Optimization: Consideration of many planning criteria and a broad set of resources so that the most efficient combination of investments can be determined.
- Efficient Pricing and Cost Allocation: Ensure that all investments receive sufficient revenue to be profitable, no consumers are charged more than the benefits they receive, and prices that can inform future decisions.
- Transparent Forward Planning: Creating a marketplace for potential new energy demands (e.g., new homes or installation of solar PV, EV, or demand response equipment) to find transparent information on the availability and cost of interconnecting to the distribution system.

Meeting all of the above goals may require coordination and harmonization across federal, state, and local regulatory authorities and other stakeholders. Towards that end, this paper proposes an auction mechanism that can coordinate distribution network planning decisions and create transparent economic incentives to help harmonize efficient decisions amongst distribution utilities, end-use consumers, and regulatory authorities. The proposed auction does not provide an all-in-one solution to the above goals, but it nonetheless addresses pricing and cost allocation for planning decisions. In particular, the auction is designed to award “installation rights” to consumers who request to install new sources of energy demand (or similarly, devices to shift or reduce energy usage) and to award “upgrade contracts” to utility companies who offer a menu of infrastructure upgrades that may be necessary to support additional energy usage. We examine how such a distribution hosting capacity auction could encourage active participation from end-users, support efficient investment in new infrastructure, recover fixed investment costs, and enable more efficient distribution system planning.

The paper proceeds as follows. The remainder of Section 0 motivates and describes potential benefits of a distribution hosting capacity auction. Section 1.3 proposes the distribution capacity mechanism design, including the generic feeder capacity auction formulation and marginal capacity pricing. Section 3.0 provides numerical examples of the distribution hosting capacity auction design with various proposed installation requests— combinations of rooftop PV panels, EV chargers, and demand response controllers. Section 4.4 discusses our results of the numerical examples and their significance.

1.1 Demand-Side Participation and Flexibility

Operation of the electric grid is becoming more complex and challenging due to the increasing amounts of weather-dependent renewable energy sources, aging transmission and distribution infrastructure, and integration of new technologies. DERs such as rooftop PV panels, EV chargers, and DR resources, offer the opportunity to bring considerable value to grid operations and may offer grid operators an important new source of flexibility for managing grid economics and reliability, especially during periods of peak load, price spikes, extreme weather events, and during large fluctuations in renewable generation output (Holmberg and Omar, 2018). DERs have the potential to improve overall system efficiency, reliability, and resilience and will be increasingly important as the power grid evolves from centralized, dispatchable forms of generation to more variable and distributed forms (Bothwell and Hobbs, 2017). However, the combination of energy, ancillary services, and capacity market incentives have not resulted in a significant amount of demand response participation in electricity markets to date (Nolan and O’Malley, 2015). One explanation for this is that the regulatory incentives of distribution utilities emphasize large capital investment with guaranteed returns over cheaper non-wires solutions like storage or demand response (Kaufman, et al., 2011; Shen, et al., 2014). Our proposed auction design would allow end-use customers to actively participate in the distribution planning process so that a wider selection of resources can be considered.

Current practices may impose a severe limitation on the amount of demand-side participation to support efficient grid investments, for example, by limiting the technology types solicited for resource acquisitions (Kahrl, 2021). Likewise, interconnection of new DERs commonly relies on an interconnection queue that evaluates new requests sequentially. This interconnection queue process is simple to execute, allocates upgrade costs according to cost causation, and provides a locational signal that penalizes projects that require more expensive upgrades; however, the price signals may be fairly coarse and could result in a prohibitively high cost allocation to a single DER project that triggers the need for network upgrades (Horowitz, et al., 2021). Interconnection queues can often result in long delays for applicants and insufficient network upgrades. Inefficiencies in the interconnection queue process can cause many projects to be canceled when they would have otherwise been economical. Considering multiple projects simultaneously, instead of in sequence, would only further increase the number of financially viable projects.

National regulations and other policies have been announced to encourage DER integration in wholesale markets. FERC Order 2222 requires wholesale market operators to allow participation of DERs in wholesale energy, ancillary service, and capacity markets to the greatest extent feasible, often through third-party aggregators who are able to aggregate resources into large enough quantities to impact the wholesale market. Some market operators (called Independent System Operators, or ISOs) have adopted various approaches to DER participation that predate Order 2222. For example, CAISO's monthly resource adequacy supply plans utilize DR capacity from third-party non-utility DR providers who contract and sell capacity obligations to load serving entities, where most of this capacity is procured through CAISO's Demand Response Auction Mechanism. Although significant levels of demand response has not materialized in ISO markets to date, broader participation from third-party aggregators can be expected to increase demand-side resource participation in wholesale markets as ISOs complete and implement their Order 2222 compliance plans.

While compliance with Order 2222 is likely to encourage DER participation in regional ISO markets, improvements to local distribution interconnection policies may also be needed. An auction for hosting capacity on local distribution feeders could provide consumers with a transparent mechanism to gauge interconnection costs when they want to decide whether to install new devices — such as solar PV panels, EV chargers, or DR controls — that may have a significant effect on voltage and power flow in the distribution system. In some cases, installation of these devices may help alleviate distribution system conditions, and market mechanisms can encourage new demand-side participation by allowing consumers to receive financial compensation when their participation benefits the distribution grid. Examples in Section 3.0 demonstrate this advantage of the proposed capacity auction.

Aside from the proposed distribution hosting capacity auction, additional market mechanisms may also be necessary to manage real-time distribution system operations. Transactive systems — which allow the coordination of bids and offers for DERs and demand-side resources through a market interaction approach — could be administered by a DSO to achieve more efficient real-time operations (GridWise, 2019; Tarufelli, 2022; and Widergren et al., 2022). Our proposed auction mechanism is therefore designed to enable beneficial coordination with transactive systems by onboarding active participants into the transactive system, for example, by registering and verifying resource capabilities. Section 4.0 includes additional discussion about how the proposed distribution hosting capacity auction could be integrated with existing planning and operations processes in distribution systems.

1.2 Resource Portfolio Optimization

As mentioned above, current practices often use a queue-based interconnection process that evaluates interconnection requests sequentially. On one hand, this creates a “free rider” problem since requests that do not violate network constraints can be approved and allocated at only a minimum processing cost. On the other hand, when a request would violate network constraints, it also follows a cost-causation principle that allocates the full cost of an upgrade to whichever project is at the top of the interconnection queue. This cost allocation rule is simple to implement but can result in very large cost allocations to single projects, and fairness concerns could be raised if two similar projects receive vastly different cost allocations merely due to their position in the queue. If both projects were proposed within the same planning cycle, they should arguably pay similar amounts for upgrade costs.

One of the key benefits of the proposed distribution feeder capacity market is that multiple interconnection requests can be considered together and served by efficiently selecting network upgrades from a diverse set of potential solutions. System needs often vary by time and location such that multiple technologies are often needed, and in principle, transparent market pricing schemes can help inform whether a novel technology is likely to meet system needs more efficiently. Auction designs that allow broad participation and consider multiple system needs can often deliver more benefits to social welfare through economies of scale, so part of the task of auction design is to identify the broadest set of participants and system needs that should be coordinated through a single auction.

Distribution system operators consider many planning criteria before deciding which infrastructure investments should be pursued. Power flow and voltages must be maintained within the engineering limits of the devices that support the distribution network. Supply disturbances must be backed up with reliable generation and possibly network reconfiguration schemes. Distribution utilities must be prepared for extreme weather events such as hurricanes or wildfires. They could perhaps play future roles in supporting grid decarbonization or other policy goals. Today, these wide-ranging goals are often considered in isolation. A better approach would be to consider them through an integrated planning model that allows load growth and system upgrades to be considered on a level playing field that rationalizes investment decisions and provides transparency into the costs, benefits, and tradeoffs involved in the planning process. Co-optimization achieves this goal.

The primary metric for economic performance in terms of costs and benefits is based on total costs for investing and operating the distribution system. This includes the annual costs of investing in new infrastructures and necessary flexible asset upgrades, fuel costs, and all other operating and maintenance expenses. When consideration other goals or metrics is desired, it is usually desirable to translate those goals into the same units as the economic costs and benefits (e.g., dollars) so that appropriate tradeoffs can be optimized by the market mechanism. For example, a distribution utility that desires backup generation should have an idea of the cost per MW that they would be willing to pay for higher backup capability. Section 4.0 discusses in more detail how the proposed auction mechanism can be leveraged to support a broad set of goals.

1.3 Comparison to ISO Capacity Markets

While the proposed distribution hosting capacity auction takes some inspiration from existing capacity market designs in ISO markets, it includes some important differences. We describe various aspects of the two market designs and note their similarities and differences.

Capacity auctions in ISO markets can be used to support regulatory policies and price caps while potentially reducing uncertainty and risk for consumers (Newbery, 2016). Existing ISO markets have developed frameworks to compensate resources for capacity and their contribution to resource adequacy goals, in addition to revenue from the energy and ancillary services markets. Resources that are cleared in the capacity market provide an obligation to offer their capacity into the energy market. Because these resources are paid for their availability rather than energy production, generators could receive capacity market payments even when they are not needed; that is, they can receive a steady revenue stream in return for their availability. For example, in wholesale electricity markets:

> *Capacity represents a commitment of power from generators and other resources to deliver when needed, particularly in case of a grid emergency. A shopping mall, for example, builds enough parking spaces to be filled at its busiest time – Black Friday. The spaces are there when needed, but they may not be used all year round. Capacity, as it relates to electricity, means there are adequate resources on the grid to ensure that the demand for electricity can be met at all times. –PJM (PJM, 2023a)*

At the wholesale level, capacity markets are administered through auctions that occur annually (or increasingly, seasonally (PJM, 2022; MISO, 2022)), often in alignment with annual or seasonal resource adequacy assessments. The forward period of capacity market is typically about 3 years, which is meant to ensure relatively reliable load projections and to provide enough lead time for permitting, financing, and constructing new capacity resources when needed. Resources that clear the auction are paid a fixed amount per megawatt of capacity, and in return, they are obligated to offer their cleared capacity into the ISO's energy markets. Capacity payments are not conditioned on whether or not the resource is also cleared in the energy market, and capacity resources receive additional market revenue for any energy provided in the energy markets. Capacity market participation typically encompasses a broad area of technology types and broad, regional or state-wide geographic areas. Table 1.1 below summarizes the capacity markets, or equivalent/similar resource adequacy constructs, used in each ISO market.

Table 1.1. ISO Capacity Markets and Resource Adequacy Programs

ISO	Capacity Market or equivalent	Frequency	Forward Period
PJM (2023b)	Reliability Pricing Model (RPM) - Base Residual Model	Annual	3 years
	RPM - Incremental Auctions	Monthly	1 year
ISO-NE (2023)	Forward Capacity Market	Annual	3 years
NYISO (2023)	Installed Capacity Market	Annual	3 years
CAISO* (CPUC, 2023)	Resource Adequacy	Annual	3 years
MISO* (2023)	Planning Resource Auction	Annual	3 years
SPP* (2022)	Resource Adequacy Program	Annual	6 years

ISO	Capacity Market or equivalent	Frequency	Forward Period
ERCOT* (2023)	Seasonal Assessment of Resource Adequacy	Seasonal (winter/summer)	1 year

*ISO does not have a capacity market mechanism

In contrast to the capacity market (and resource adequacy) constructs used in ISOs, our proposed distribution hosting capacity auction does not award supply capacity but instead awards upgrade contracts for infrastructure that improves the ability of the distribution network to serve load. Unlike the ISO capacity market, our proposed framework also awards installation permits that confer the right to install new equipment that has the potential to stress the distribution network. This right is transferrable and does not necessarily require the permit owner to proceed with their installation. Rather, a permit holder may elect to resell their permit to another end user, perhaps incurring a locational hosting capacity conversion rate, or they may redeem the permit in a future hosting capacity auction to receive a payment for the unused capacity, perhaps at a profit.

Ideally, all new interconnection requests are first cleared by the hosting capacity auction. Consumers who are awarded a permit and opt to install are then guaranteed reliable service for their additional load (or a reliable sink for power injection if they are installing solar PV panels or other distributed energy sources). The distribution hosting capacity auction is intended to be run in parallel with (or to replace) existing distribution system planning activities and will improve the efficiency of such planning processes by opening up a wider menu of resources to help alleviate distribution system congestion or other operational issues. Table 1.2 below summarizes some of the key differences between the two types of capacity markets.

Table 1.2. Distribution Hosting Capacity Auction vs. ISO Capacity Markets

Attribute	Distribution Hosting Capacity Auction	ISO Capacity Market
Frequency	Aligned with distribution system planning procedures	Seasonal/Annual
Forward Period	3-10 years	3-6 years
Supply Obligation	Network upgrade contracts	Energy market participation
Consumer Benefit	Installation permits	Reliable energy supply
Geographic Area	Single distribution feeder or network	Regional/state-wide

The proposed distribution hosting capacity auction may also be able to support implementation of transactive energy systems. There are two main roles that it could support:

1) Resources cleared by the distribution hosting capacity auction could be automatically registered for participation in a transactive energy market, analogously to requirements for cleared capacity resources to participate in ISO energy markets.
2) Network upgrade contracts and installation permits can also be traded in the transactive system to allow efficient reallocation of awards between runs of the distribution hosting capacity auction.

Regarding the second item above, this transferability of rights is important for the successful implementation of the proposed auction design. Trading of upgrade contracts and installation permits would allow the auction, which is a planning model, to be run well before end users may have decided to invest in new solar PV panels or other devices considered in the auction. Speculators may therefore try to buy such permits ahead of time at a low cost in order to resell to consumers at a later date, or, if no one is willing to buy, then the permits can be sold back to the auction at less cost than additional network upgrades. On the network upgrade side, a utility or 3rd-party contractor (or a forward-looking startup) could take advantage of economies of scale and decide to overbuild its supply obligation. This additional capacity, having not been cleared in the market, could either be offered at lower costs in subsequent markets or the rights to offer this additional capacity could be transferred to another entity.[1]

2.0 Distribution Hosting Capacity Auction

The purpose of a feeder capacity auction is to directly identify and fund cost-effective investments to serve the needs of end users on the distribution feeder. Rather than supplementing the revenues of supply resources (i.e., generation capacity) as in ISO capacity markets, the distribution hosting capacity auction is designed to pay for network upgrades (i.e., feeder capacity) and allocate installation permits to new end use loads. Once a cost-effective set of feeder investments is identified, the rights to the increased feeder capacity are allocated to the auction participants whose bid values exceeded the cost of the increased feeder capacity. Those participants would be given the right to increase their power consumption (or production) at the hours specified in their award, to sell their right to another entity who would like to increase power consumption (or production) at the same location and specified hours, or if they have not already installed their equipment, they may resell their right during a subsequent auction.

2.1 Generic Feeder Capacity Auction Formulation

Below, we formulate a generic feeder capacity auction that is largely based on the DistFlow model for optimal capacitor placement (Baran and Wu, 1989). The objective function maximizes total value of new consumption minus the cost of required feeder upgrades. New consumption p_i is the nominal planned energy consumption (for example, a positive kW amount for installation of an EV charger or a negative amount for a solar panel installation). Each consumption request p_i is submitted with a bid value V_i that represents the maximum that the user is willing to pay (or, if negative, the amount they must be paid) if their request is awarded. Typically, p_i will be a positive variable so that a positive V_i indicates a benefit to the end-user while a negative V_i indicates a cost or inconvenience to the end-user (e.g., the amount they would like to be paid to participate in a DR program). Feeder upgrades u_j have arbitrary units (e.g., could be in kW, kVAr, kVA, kV, or unitless) to represent any generic upgrade that the distribution utility might pursue, and each upgrade is submitted with a cost offer C_j that represents the all-included cost of the upgrade.

$$\max_{p_i,u_i} \sum_i V_i p_i - \sum_j C_j u_j \qquad (1)$$

Energy consumption at each location is equal to the existing consumption profile P_{nt} at location n plus the additional capacity p_i times the new consumption profile P_{it} for all new consumption profiles at location n. The consumption profile P_{it} is a dimensionless value (per nominal kW, p_i) that represents the amount of energy that the planned installation i consumes in each period t, which is a positive number for energy consumption or a negative number for energy production

[1] Note that overbuilding upgrade contracts may require the market entity to keep two parallel system models: one using the "cleared" network upgrades and another of the actual installed infrastructure.

(e.g., solar installation). Utility-owned energy supply (e.g., DERs), if any, is included in p_{nt}^{supply} and also contributes to power balance.

$$p_{nt} = P_{nt} + \sum_{i \in \mathcal{I}_n} P_{it}\, p_i - p_{nt}^{\text{supply}} \qquad [\lambda_{nt}^{\text{P}}] \tag{2}$$

Changes in reactive power consumption profile Q_{nt}, if any, are calculated similarly. For example, reactive power may be affected by an industrial customer that installs an induction motor (inductive load) or a data center that installs new computer equipment (capacitive load), and are given by the new reactive power profile parameter Q_{it}, which is a relative value in kVAr/kW since it is multiplied by the nominal kW capacity p_i. Increases or decreases in reactive power injection due to system upgrades are also included, such as by installing capacitor banks with reactance X_j or by a dynamic reactive power source q_{jt}, such as a static VAR compensator (SVC).

$$q_{nt} = Q_{nt} + \sum_{i \in \mathcal{I}_n} Q_{it}\, p_i - \sum_{j \in \mathcal{J}_n} (X_j u_j) v_{nt}^2 - q_{nt}^{\text{supply}} \qquad [\lambda_{nt}^{\text{Q}}] \tag{3}$$

The amount of real power supplied by the distribution operator at a node n and period t is given by p_{nt}^{supply}. It has a lower bound of P_n^{LB} and a possible change due to upgrade of $P_j^{\text{dec}} u_j$ (both typically zero). The upper bound is P_n^{UB}, which will typically represent the power capacity of the feeder's interconnection, and an upgrade quantity $P_j^{\text{inc}} u_j$. Unless the distribution operator owns DERs within the feeder, the supply will only be positive at the feeder's root node. Reactive power supply q_{jt}^{supply} at node n has a lower (capacitive) limit of Q_n^{LB} plus any inductive upgrade $Q_j^{\text{ind}} u_j$, and it has an upper limit of Q_n^{UB} plus any capacitive upgrade $Q_j^{\text{cap}} u_j$.

$$-p_{nt}^{\text{supply}} \leq P_n^{\text{LB}} + \sum_{j \in \mathcal{J}_n^{\text{node}}} P_j^{\text{dec}} u_j \qquad [\mu_{nm}^{\text{Pdec}}] \tag{4}$$

$$p_{nt}^{\text{supply}} \leq P_n^{\text{UB}} + \sum_{j \in \mathcal{J}_n^{\text{node}}} P_j^{\text{inc}} u_j \qquad [\mu_{nm}^{\text{Pinc}}] \tag{5}$$

$$-q_{nt}^{\text{supply}} \leq Q_n^{\text{LB}} + \sum_{j \in \mathcal{J}_n^{\text{node}}} Q_j^{\text{ind}} u_j \qquad [\mu_{nm}^{\text{Qind}}] \tag{6}$$

$$q_{jt}^{\text{supply}} \leq Q_n^{\text{UB}} + \sum_{j \in \mathcal{J}_n^{\text{node}}} Q_j^{\text{cap}} u_j \qquad [\mu_{nm}^{\text{Qcap}}] \tag{7}$$

Real and reactive power flows on the feeder are calculated for each line using the Baran and Wu (1989) DistFlow model. Each line is specified by the from and to buses n and m, respectively, resistance R_{nm}, reactance X_{nm}, voltage magnitude v_n, current c_{nmt}, and real and reactive power flows p_{nmt}^{flow} and q_{nmt}^{flow}. The DistFlow model determines the real and reactive power loss on each line and the voltage at each bus. It assumes a radial network.

$$p_{nmt}^{\text{flow}} = p_{mt} + R_{nm}(c_{mnt})^2 + \sum_{l} p_{mlt}^{\text{flow}} \qquad [\phi_{nmt}^{\text{Pflow}}] \tag{8}$$

$$q_{nmt}^{\text{flow}} = q_{mt} + X_{nm}(c_{mnt})^2 + \sum_{l} q_{mlt}^{\text{flow}} \qquad [\phi_{nmt}^{\text{Qflow}}] \tag{9}$$

$$v_n^2 - v_m^2 = 2\left(R_{nm}p_{nmt}^{\text{flow}} + X_{nm}q_{nmt}^{\text{flow}}\right) - (R_{nm}^2 + X_{nm}^2)(c_{mnt})^2 \qquad [\phi_{nmt}^{\text{Vdrop}}] \tag{10}$$

$$v_n^2(c_{nm})^2 = \left(p_{nmt}^{\text{flow}}\right)^2 + \left(q_{nmt}^{\text{flow}}\right)^2 \qquad [\phi_{nmt}^{\text{Ohm}}] \tag{11}$$

Power flow and voltages are constrained to be within their design limits in each interval t in the auction period. The set $j \in \mathcal{J}_{nm}^{\text{line}}$ designates that upgrade j improves the design limits of line nm. Most commonly, this would be used to model an improvement in the MVA rating of the feeder's substation. It would also be possible to use these constraints to model a reconductoring of the feeder's distribution lines, but note that changes to a line's parameters (resistance and reactance) are not reflected in this auction formulation.

$$p_{nmt}^{\text{flow}} \leq P_{nm}^{\max} + \sum_{j \in \mathcal{J}_{nm}^{\text{line}}} P_j^{\text{inc}} u_j \qquad [\delta_{nmt}^{\text{Plim+}}] \tag{12}$$

$$-p_{nmt}^{\text{flow}} \leq P_{nm}^{\max} + \sum_{j \in \mathcal{J}_{nm}^{\text{line}}} P_j^{\text{inc}} u_j \qquad [\delta_{nmt}^{\text{Plim}-}] \tag{13}$$

$$q_{nmt}^{\text{flow}} \leq Q_{nm}^{\max} + \sum_{j \in \mathcal{J}_{nm}^{\text{line}}} Q_j^{\text{cap}} u_j \qquad [\delta_{nmt}^{\text{Qlim+}}] \tag{14}$$

$$-q_{nmt}^{\text{flow}} \leq Q_{nm}^{\max} + \sum_{j \in \mathcal{J}_{nm}^{\text{line}}} Q_j^{\text{ind}} u_j \qquad [\delta_{nmt}^{\text{Qlim}}] \tag{15}$$

$$\sqrt{\left(p_{nmt}^{\text{flow}}\right)^2 + \left(q_{nmt}^{\text{flow}}\right)^2} \leq S_{nm}^{\max} + \sum_{j \in \mathcal{J}_{nm}^{\text{line}}} S_j^{\text{inc}} u_j \qquad [\delta_{nmt}^{\text{Slim}}] \tag{16}$$

$$V_n^{\min} \leq v_n \leq V_n^{\max} \qquad [\delta_{nmt}^{\text{Vlim}}] \tag{17}$$

Each new consumption is bounded between zero and an upper limit. The specific formulation can easily vary depending on convenience; here, it is formulated with a nominal install capacity P_i^{nom} and a maximum installation quantity $N_i^{\max}$. The cleared number of installations n_i could alternatively be constrained to integer values so that only discrete changes are allowed. EV chargers cannot be partially installed, for example. This change would add nonconvex integer constraints to the market clearing model (in addition to the nonconvex nonlinear constraints (8)-(11)) and is therefore omitted from this illustrative formulation.

$$0 \leq p_i \leq P_i^{\text{nom}} n_i \tag{18}$$

$$0 \leq n_i \leq N_i^{\max} \tag{19}$$

Each network upgrade is also bounded between zero and an upper limit. Note that the investment variable u_i can also be made integer so that only discrete investments are allowed, but this would also result in additional nonconvexities in the market clearing model.

$$0 \leq u_j \leq U_j^{\max} \tag{20}$$

For ease of presentation, we assume the market is convex and therefore abides by the typical properties of convex markets. The solution of the above market formulation provides the optimal new consumption capacities p_i^* and network upgrades u_j^*. In particular, each consumer i is awarded a right to consume (or produce) $P_{it}\ p_i^*$ kW at its location n and time t, and the network operator or 3rd party contractor that offered upgrade j is awarded a contract if $u_j^* = 1$ such that the set of awarded contracts will increase the network capacities by $p_{nm}^{\mathrm{inc}*}$, $q_{nm}^{\mathrm{inc}*}$, $s_{nm}^{\mathrm{inc}*}$, $v_{nm}^{\mathrm{inc}*}$, and $v_{nm}^{\mathrm{dec}*}$.

The solution generates gross consumer benefits of $\sum_i V_i p_i^*$ and total investment cost of $\sum_j C_j u_j$. The auction system now needs a system for determining how to allocate the investment costs. We propose a marginal pricing method that sets the price of system upgrades at their marginal contribution to the overall market surplus gained and the price of installations at their marginal cost to reliably serve.

2.2 Marginal Distribution Capacity Pricing

Marginal prices are typically derived from the dual problem of the auction formulation, or if the auction formulation is nonlinear, then prices can instead be derived from the Karush-Kuhn-Tucker (KKT) conditions of a locally optimal solution. Since the DistFlow model introduces nonconvex AC power flow constraints, the market solution may only be locally optimal, and therefore, the resulting marginal prices may not be unique. A rigorous description of the KKT conditions is left for future work; the brief description of marginal prices is that, in principle, all market participants will pay or be paid the same amount per unit of the supplied commodity at a given time and location.

The resulting marginal prices are the Lagrange multipliers $\lambda_{nt}^{\mathrm{P}}$ and $\lambda_{nt}^{\mathrm{Q}}$ from the nodal power balance constraint and the multipliers $\delta_{nmt}^{\mathrm{Plim}+}$, $\delta_{nmt}^{\mathrm{Plim}-}$, $\delta_{nmt}^{\mathrm{Qlim}+}$, $\delta_{nmt}^{\mathrm{Qlim}-}$, and $\delta_{nmt}^{\mathrm{Slim}}$ for the branch power flow capacity constraints. The dual variable $\lambda_{nt}^{\mathrm{P}}$ is equal to the change in total market surplus per increase in real power consumption at node n and time t. The dual variable $\lambda_{nt}^{\mathrm{Q}}$ is equal to the change in market surplus per increase in reactive power consumption at node n and time t, is also used to value the effects of injecting (or withdrawing) reactive power to help regulate voltage. The dual variable $\delta_{nmt}^{\mathrm{Plim}+}$ ($\delta_{nmt}^{\mathrm{Plim}+}$) is equal to the value of increasing (or decreasing) the real power limit of a branch, typically the value of increasing the real power capacity of the substation at the T&D interface. The multipliers $\delta_{nmt}^{\mathrm{Qlim}+}$, $\delta_{nmt}^{\mathrm{Qlim}-}$, and $\delta_{nmt}^{\mathrm{Slim}}$ are similar but refer to the marginal value of increasing the reactive and apparent power capacity of a branch.

We assume that each consumer i is located at a single node n. For a consumer i located at node n, the decision to install p_i results in an increase in real power consumption of $P_{it}\ p_i$ and an increase in reactive power consumption of $Q_{it}\ p_i$ in each period t. To pay for the cost of upgrades, the consumer i is therefore allocated the following market settlement, where a positive result indicates the amount it will pay to the distribution operator.

$$Settlement_i = \sum_t \left(\lambda_{nt}^{\mathrm{P}} P_{it} + \lambda_{nt}^{\mathrm{Q}} Q_{it}\right) p_i$$

The market settlement for each upgrade j is computed similarly, with the exception that we do not assume each upgrade j must correspond to a single network node or branch location. An upgrade receives payment for improvements to the feeder's reactive power profile and for changes in the feeder's operational limits. The upgrades are financed by the following market settlement, where a negative result indicates the amount of money paid for the upgrade:

$$
\begin{aligned}
Settlement_j = & \sum_t \sum_{n \in \mathcal{N}_j} \left(\lambda_{nt}^{\mathrm{P}} P_j^{\mathrm{inc}} + \lambda_{nt}^{\mathrm{Q}} \left(Q_j^{\mathrm{cap}} - Q_j^{\mathrm{ind}} + X_j v_n^2 \right) \right) u_j \\
& + \sum_t \sum_{nm \in \mathcal{K}_j} \left(\left(\delta_{nmt}^{\mathrm{Plim+}} + \delta_{nmt}^{\mathrm{Plim-}} \right) P_j^{\mathrm{inc}} + \left(\delta_{nmt}^{\mathrm{Qlim+}} + \delta_{nmt}^{\mathrm{Qlim-}} \right) Q_j^{\mathrm{cap}} + \delta_{nmt}^{\mathrm{Slim}} S_j^{\mathrm{inc}} \right) u_j
\end{aligned}
$$

At this early stage of proposing the auction model, we refer to numerical example results in Section 3.0 to indicate this marginal pricing method's properties regarding the allocation of market surplus, revenue sufficiency, and incentives. Pending theoretical confirmation, we expect that the following properties can be established (largely following the typical network pricing analysis of Schweppe, et al., 1988):

- The market surplus (i.e., net benefit) generated by the auction is nonnegative.
- The amount of revenue collected by the auction is at least as much as the amount paid to auction participants.
- Under the assumptions of perfect competition, the installation permit and upgrade contract allocations maximize the net benefits (e.g., profits) of all auction participants at the given locationally and temporally dependent prices.

Theoretical guarantees of the above properties remain to be proven in future work. In each of the examples solved in Section 3.0, there is always at least enough payments collected from end-use customers to pay the amounts owed for upgrade contracts, i.e., all examples demonstrated revenue sufficiency. Two examples collected an excess of end-user payments compared the amounts owed for upgrade contracts; that is, they resulted in a settlement surplus. This settlement surplus can be allocated back to consumers, or to the distribution operator, or anything in between; that is, it is a policy decision by the entity that hosts the auction.

3.0 Numerical Examples

The issues raised in this paper are motivated by anticipated changes in the distribution operations, especially a transition from passive energy consumers to more active participation in the electric system. This transition is also referred to as expanding the "grid-edge." As more conventional generation is replaced by renewable resources, active participation by resources on the distribution side may be able to provide additional energy and flexibility to help maintain reliable electricity. The following examples anticipate these future changes in the system by illustrating how solar PV panels, EV chargers, and DR controllers might participate in the proposed distribution hosting capacity auction.

First, we model a distribution feeder topology that consists of one root substation where the T&D interface is located and three nodes labeled A, B, and C, respectively, as shown in the single line diagram in Figure 1. The physical attributes and engineering limits for the example feeder are provided in

Table 3.1 and Table 3.2, and a menu of proposed upgrades and their costs are shown in Table 3.2. The offered upgrades include a substation improvement that increases the capacity of the substation by 100 kVA, , or up to 10 capacitor banks at any node A, B, or C with each capacitor bank providing 10j Ω of reactance.

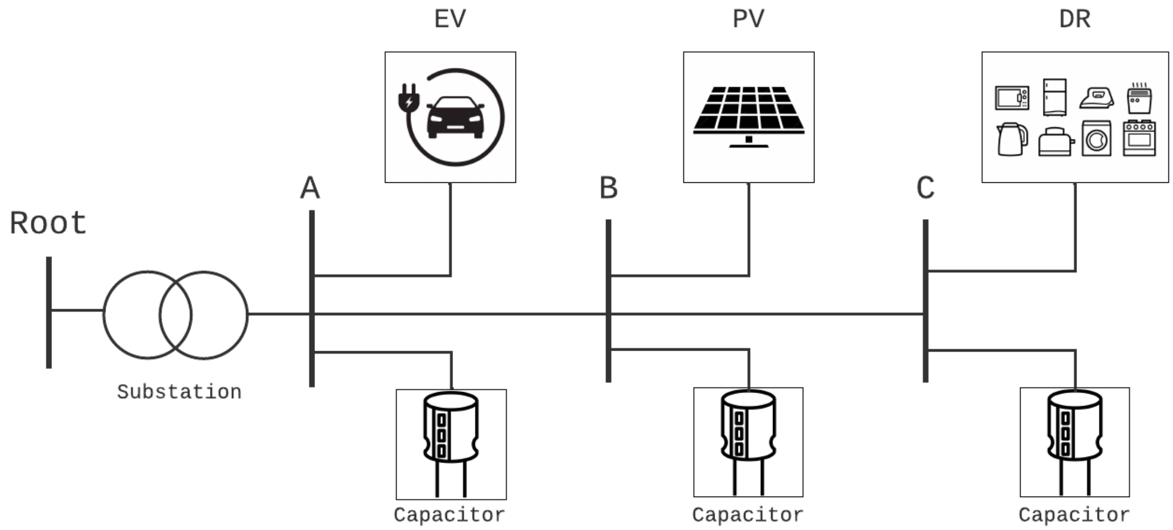

Figure 1. Single Line Diagram of a Sample Feeder in a Distribution Network

Table 3.1. Sample Feeder Node Attributes

Node	Morning (kW)	Daytime (kW)	Evening (kW)	Morning (kVAr)	Daytime (kVAr)	Evening (kVAr)	Vmin (p.u.)	Vmax (p.u.)
Root	0	0	0	0	0	0	0.95	1.05
A	500	1000	600	50	100	60	0.95	1.05
B	500	800	1200	50	80	120	0.95	1.05
C	500	800	1200	50	80	120	0.95	1.05

Table 3.2. Sample Feeder Branch Attributes

To	From	Resistance (Ω)	Reactance (Ω)	Pmax (kW)	Qmax (kVAr)	Smax (kVA)
Root	**A**	0	0	3200	3200	3200
A	**B**	0.00007	0.00001	3000	3000	3000
B	**C**	0.00007	0.00001	3000	3000	3000

Table 3.3. Upgrade Costs and Attributes

Resource	Node	Max upgrades	Upgrade cost	kW limit increase	kVAr limit increase	Capacitive Reactance (Ω) increase
Substation	Root	1	$4500	100	100	
Capacitor bank	A	10	$100			10j
Capacitor bank	B	10	$100			10j
Capacitor bank	C	10	$100			10j

The example distribution hosting capacity auction will allocate permits for new EV, PV, and DR installations. We include three operating periods (i.e., morning, daytime, and evening) to consider a range of operating conditions. Table 3.4 shows the resources attributes and their profiles during the three periods. The attributes of each permit type are based on the following assumptions:

- EV: 10 consumers request capacity to charge up to 22 kW at any time, which they each value at a net present value of $1000.
- PV: 10 consumers request to install solar PV panels that will inject up to 10 kW during daytime, and they each expect an NPV of $250 in utility bill reduction.
- DR: 10 consumers are willing to activate DR controllers that reduce their energy usage by 15 kW in the evening and then 30% and 50% less reduction during daytime and morning, respectively. They are willing to participate in the program this year if they receive at least $600.

The above permit types are for illustrative purposes only and may not be realistic. It can be expected that more detailed permit types will be developed as the auction design comes closer to implementation: EV permit classes for different types of charging policies; PV permit classes for differently facing panels or solar+PV systems; DR permit classes with varying interruption frequency and timing; and perhaps other permit classes for entirely different energy uses.

Table 3.4. Installation Attributes

Permit Type	Node	End users	Nominal capacity	Value	Morning profile	Daytime profile	Evening profile
EV	A	10	22 kW	$1000	1	1	1
PV	B	10	10 kW	$250	0	-1	0
DR	C	10	15 kW	-$600	-0.5	-0.7	-1

In the first three of the following examples, only one installation type is allowed to participate in the auction, allowing us to see the optimal planning decision when each type is considered independently. The fourth example shows the results when all installation permits are planned simultaneously, resulting in a more efficient set of upgrades and more benefits created by the auction.

3.1 Example 1: DR controller installations

In Example 1, we model a benchmark case with only DR controller installations allowed in the auction model. According to the attributes listed in Table 3.4, the assumed availability of DR is lowest in the morning, higher in the daytime, and highest in the evening, providing a maximum energy use reduction of 15 kW.

The optimal installation and upgrade decisions and the market clearing prices are shown in

Table 3.5 and Table 3.6. Example 1, DR Upgrade Contracts, Branches. The results show that no customers are willing to activate their DR controllers and no system upgrades are required. No installation permits or upgrade contracts are allocated, and the real and reactive capacity prices at each node and each branch are zero.

Table 3.5. Example 1, DR Installation and Upgrade Contracts, Nodes

Node	Permits	Contracts	Morn $/kW	Day $/kW	Eve $/kW	Morn $/kVAr	Day $/kVAr	Eve $/kVAr
Root	0	0	0	0	0	0	0	0
A	0	0	0	0	0	0	0	0
B	0	0	0	0	0	0	0	0
C	0	0	0	0	0	0	0	0

Table 3.6. Example 1, DR Upgrade Contracts, Branches

Fm	To	Contracts	Morn $/kW	Day $/kW	Eve $/kW	Morn $/kVAr	Day $/kVAr	Eve $/kVAr
Root	**A**	0	0	0	0	0	0	0
A	**B**	0	0	0	0	0	0	0
B	**C**	0	0	0	0	0	0	0

The summary financial settlements and resulting profits for each market participant are shown in Table 3.7**Error! Reference source not found.**. Since no installation permits or upgrade contracts are allocated, no financial settlement is required, and there are no profits generated by the market.

Table 3.7. Example 1, DR Auction Results

	Permits/Contracts (Size)	Settlement	Net Value
DR	0	$0	$0
Substation	0	$0	$0
Capacitor bank A	0	$0	$0
Capacitor bank B	0	$0	$0
Capacitor bank C	0	$0	$0
Settlement surplus	n/a	$0	$0
Total	0	$0	$0

This “do-nothing” solution is a legitimate and efficient market solution given this example’s assumptions. Aside from not allocating any new permits or contracts, this example shows that the current distribution network is sufficient to serve the baseline load with no upgrades. In addition, the example illustrates the current status quo where very little energy is provided by demand response. Later, Example 4 will show that this trend can be reversed by co-optimizing DR with other customer needs that would otherwise be more expensive to serve.

3.2 Example 2: Rooftop PV panel installations

Next, in Example 2, we only allow rooftop solar PV installations to be permitted by the market. It is assumed that each PV panel installation permit requests a rated output of 10kW, that they only inject energy during the daytime, and that each customer is willing to pay $250 for a PV permit.

The optimal installation and upgrade decisions and the market clearing prices are shown in

Table 3.8 and Table 3.9. The results show that the existing network has sufficient capacity to service all 10 customer requests for solar PV installation, so no upgrade contracts are required.

Capacity prices are $0 in each time period at each node and each branch, so the permits are allocated at no cost to the consumers.

Table 3.8. Example 2, PV Installation and Upgrade Contracts, Nodes

Node	Permits	Contracts	Morn $/kW	Day $/kW	Eve $/kW	Morn $/kVAr	Day $/kVAr	Eve $/kVAr
Root	0	0	0	0	0	0	0	0
A	0	0	0	0	0	0	0	0
B	10	0	0	0	0	0	0	0
C	0	0	0	0	0	0	0	0

Table 3.9. Example 2, PV Upgrade Contracts, Branches

Fm	To	Contracts	Morn $/kW	Day $/kW	Eve $/kW	Morn $/kVAr	Day $/kVAr	Eve $/kVAr
Root	**A**	0	0	0	0	0	0	0
A	**B**	0	0	0	0	0	0	0
B	**C**	0	0	0	0	0	0	0

The summary financial settlements and resulting profits for each market participant are shown in Table 3.10. Since no distribution upgrades are needed, the customers pay $0 for their permits, and allocating the installation permits generates a net benefit of $2500.

Table 3.10. Example 2, PV Auction Results

	Permits/Contracts (Size)	Settlement	Net Value
PV	10 (100 kW)	$0	$2500
Substation	0	$0	$0
Capacitor bank A	0	$0	$0
Capacitor bank B	0	$0	$0
Capacitor bank C	0	$0	$0
Settlement surplus	n/a	$0	$0
Total	10/0	$0	$2500

Like Example 1, Example 2 also illustrates the current status quo where customers are typically able to install solar PV without disrupting the distribution network. Because solar PV injects power at locations that are primarily loads, the net effect reduces the amount of power flowing into the distribution network. However, larger amounts of solar PV installations has the potential to reverse the direction of power flow and could exacerbate voltage issues in the distribution system. Although the issue does not occur in these examples, future case studies may study this potential issue more closely.

3.3 Example 3: EV charger installations

In the previous two examples, the existing distribution network is sufficient to serve the baseline demand and to support the requested PV installations without any upgrades. The following example illustrates a case where network upgrades are needed in order to support installation of EV chargers, and they incur significant cost. For simplicity, we assume that each customer requests 22kW of reliable service to charge their EV at any time of day. This assumed behavior of the permit class provides maximum convenience to the customer. Future case studies may examine the possibility of service quality differentiation – e.g., potentially "cheaper" EV permit classes that allow varying degrees of managed charging by the distribution utility.

The optimal installation and upgrade decisions and the market clearing prices are shown in

Table 3.11 and Table 3.12. The results allocate 7.69 EV charger installation permits (a total of 169kW of charger capacity) and award construction contracts for a substation upgrade and capacitor bank upgrades to support the allocated EV chargers. Unlike the solar PV installations in Example 2, the EV chargers in this example would overload the distribution system if all permits were granted. Instead, only 7 of the 10 customers are allocated an installation permit, and one customer is only allocated a partial permit, which may need to be rounded to a whole number according to some policy described by the auction rules.[1] Prices for the EV charger permits based on the evening capacity price for real power, which is set at $45.45/kW at node A, where the EV chargers are requested. Real power capacity prices at nodes B and C are higher due to network losses. Because the capacitor bank upgrades provide reactive power (equal to $X_j v_n^2$), their contracts are paid based on the capacity prices for the reactive power delivered by the capacitor banks, $10.40/kVAr at node B and $10.89/kVAr at node C. Like for real power, the marginal reactive power capacity prices become lower closer to the root node due to the reduction in reactive power losses. The reactive power price at node A is consequently too low to support capacitor bank upgrades. Lastly, the substation upgrade increases the capacity of the Root-A branch and is paid $45.45/kW for increased real power capacity and $8.61/kVAr for increased reactive power capacity.

Table 3.11. Example 3, EV Installation and Upgrade Contracts, Nodes

Node	Permits	Contracts	Morn $/kW	Day $/kW	Eve $/kW	Morn $/kVAr	Day $/kVAr	Eve $/kVAr
Root	0	0	0	0	0	0	0	0
A	7.69	0	0	0	$45.45	0	0	$8.61
B	0	10	0	0	$51.00	0	0	$10.40
C	0	10	0	0	$54.16	0	0	$10.89

Table 3.12. Example 3, EV Upgrade Contracts, Branches

Fm	To	Contracts	Morn $/kW	Day $/kW	Eve $/kW	Morn $/kVAr	Day $/kVAr	Eve $/kVAr
Root	**A**	1	0	0	$45.45	0	0	$8.61
A	**B**	0	0	0	$51.00	0	0	$10.40
B	**C**	0	0	0	$54.16	0	0	$10.89

The summary financial settlements and resulting profits for each market participant are shown in Table 3.13. The pricing results cause all of the surplus generated by the market to be allocated to the firm (distribution utility or 3rd-party contractor) performing the network upgrades, and the consumers are required to pay the maximum amount that they are willing to pay. EV charger requests set the marginal prices in the auction and therefore pay their full willingness to pay (the

[1] It may be difficult to handle partial allocations in a theoretically satisfactory way, as these partial allocations are the result of omitted integer constraints that complicate the pricing of the auction results. However, the magnitude of this issue may disappear as the size of the market grows larger. It may be sufficient to either allocate the partial permit (which can be "completed" in a later auction) or not allocate the partial permit (which may require the market entity to find additional funds to pay for all upgrade contracts).

price $45.45/kW is equal to the bid price divided by evening capacity: $1000/22kW). That is, the marginal pricing policy sets the price so that each of the 10 EV charging permit requestees are indifferent to whether they are one of the 7 selected to purchase a charging permit or one of the 3 who do not.[1] The substation upgrade receives a profit surplus of $907.45, the capacitor banks at node B receive a profit surplus of $45.21, and the capacitor banks at node C receive a profit surplus of $55.7. Although this results in no profit or surplus to consumers, the outcome is still economically rational: no one is charged more than they are willing to pay and there are no available upgrades that would support the installation requests at a lower cost.

Table 3.13 Example 3, EV Auction Results

	Permits/Contracts (Size)	Settlement	Net Value
EV	7.7 (169 kW)	-$7690.47	$0
Substation	1 (100 kW, 100kVAr)	$5407.45	$907.45
Capacitor bank A	0	$0	$0
Capacitor bank B	10 (100 Ω)	$1045.21	$45.21
Capacitor bank C	10 (100 Ω)	$1055.77	$55.77
Settlement surplus	n/a	$182.03	$182.03
Total	7.7/21	$0	$1190.47

3.4 Example 4: Co-optimized DR, PV, and EV charger installations

The previous three examples illustrated how DR controllers, PV panels, and EV chargers could participate the auction independently. This following example allows all installation requests to be considered simultaneously to demonstrate how co-optimization results in more efficient investment decisions that improve the total economic surplus created by the market.

The optimal installation and upgrade decisions and the market clearing prices are shown in Table 3.14 Example 4, Co-optimized Installation and Upgrade Contracts, Nodes and Table 3.15. Example 4, Co-optimized Upgrade Contracts, Branches. The results allocate all thirty installation requests, totaling 220 kV of EV chargers, 100 kW of solar PV panels, and 150 kW of DR. To support the installation permits, 9.36 permits for capacitor bank upgrades at node C are awarded. Compared to Example 3, the real and reactive power capacity prices are now slightly lower.

Table 3.14 Example 4, Co-optimized Installation and Upgrade Contracts, Nodes

Node	Permits	Contracts	Morn $/kW	Day $/kW	Eve $/kW	Morn $/kVAr	Day $/kVAr	Eve $/kVAr
Root	0	0	0	0	0	0	0	0
A	10	0	0	0	$40.36	0	0	$8.39
B	10	0	0	0	$45.17	0	0	$9.93
C	10	9.36	0	0	$47.73	0	0	$10.32

[1] In the example, all 10 EV charger requestees submit identical bids. In reality, slight differences in the bid prices and differences in charger location would become the “tiebreaker”.

Table 3.15. Example 4, Co-optimized Upgrade Contracts, Branches

Fm	To	Cont.	Morn $/kW	Day $/kW	Eve $/kW	Morn $/kVAr	Day $/kVAr	Eve $/kVAr
Root	**A**	0	0	0	$40.36	0	0	$8.39
A	**B**	0	0	0	$45.17	0	0	$9.93
B	**C**	0	0	0	$47.73	0	0	$10.32

The summary financial settlements and resulting net value for each market participant are shown in Table 3.16 below. In comparison with Example 3, we see that the DR programs are a more economic solution to supporting the requested EV chargers and consequently they have replaced the previous substation and capacitor bank B upgrades. This also increases the available distribution hosting capacity enough so that all EV charger permits can be allocated. The settlement from the EV charger permits is used to pay the customers who have agreed to activate their DR controllers, the cost of the capacitor banks at node C, and a small surplus that is collected by the market entity. The solar PV permits do not pay anything because their output occurs in the middle of the day when the capacity prices are $0 (i.e., there are no binding limits). Each customer class receives more benefit from the auction than their bid, so each received a positive net value. The capacitor bank contract is paid at the offered cost.

Table 3.16. Example 4, Combined Auction Results

	Permits/Contracts (Size)	Settlement	Net Value
EV	10 (220 kW)	-$8879.24	$1120.76
PV	10 (100 kW)	$0	$2500
DR	10 (150 kW)	$7159.14	$1159.14
Substation	0	$0	$0
Capacitor bank A	0	$0	$0
Capacitor bank B	0	$0	$0
Capacitor bank C	9.36 (93.61 Ω)	$936.05	$0
Settlement surplus	n/a	$784.05	$784.05
Total	30/9.36	$0	$5563.95

Significantly fewer system upgrades are needed when all customer requests are considered simultaneously. Instead of a substation upgrade and 20 capacitor banks at two nodes, the new investment plan only requires 9.36 capacitor banks (93.61j Ω) to be installed at node C (as noted previously, the handling of partial allocations may be more difficult theoretically than in practice). The capacitor bank upgrade contract pays at the cost of the upgrade.

This final example results in significant profits allocated to the customers. Each EV charger permit is charged $887.92, $112.08 less than they were willing to pay. Each PV install permit is awarded at no cost, providing each of those customers with their full $250 benefit from the installation. Finally, the DR permits are each paid $715.91, which is $115.91 greater than the $600 that they requested for activating their DR controllers. Importantly, these economic gains are apparently only possible when the customers are able to participate in the auction simultaneously.

4.0 Discussion

The proposed distribution hosting capacity auction creates a new paradigm for efficient distribution network planning decisions. Broad participation from wider groups of consumers allows this market design to generate larger benefits, significantly more than when customer requests are considered by individual technology type. In fact, the total surplus created in Example 4 is greater than the surplus created in all of the other examples combined.

A summary of the economic benefits and settlement surplus are shown in Table 4.1. Surplus below. One result from the use of marginal prices is a small settlement surplus that is collected by the market entity. So far, we have not addressed the question of what determines the allocation of this extra economic surplus. Settlement surplus could be allocated back to market participants or retained by the market entity to pay for the overhead costs of running the market. A third option could be to introduce a secondary market to allocate rights to the surplus, which would be analogous to financial transmission rights allocated by ISOs. A more detailed consideration of the surplus allocation may be an avenue for future work but may ultimately become a practical or political decision to satisfy stakeholders.

Table 4.1. Surplus Allocation Summary

	Example 1	**Example 2**	**Example 3**	**Example 4**
Installation type	DR	PV	EV	DR, PV, EV
Consumer surplus	0	$2,500	0	$4,779.90
Producer surplus	0	0	$1,008.43	0
Settlement surplus	0	0	$182.03	$784.05
Total benefits	0	$2,500	$1,190.47	$5,563.95

Example 4 generates the most economic benefits, which are coincidentally entirely allocated to the consumers. This result is by no means guaranteed in other cases, but it is worth examining why the economic benefits fall where they do. In our case, the “consumer” and “producer” categories are somewhat misleading; they are really categories for end-use customers of the distribution system versus a distribution utility (or 3rd-party contractor) that is builds, maintains, and upgrades the distribution network. One of the key lessons from Example 4 is that the proposed market identifies complementary requests from different consumer types such that fulfilling one consumer request makes it easier for the distribution system to support another request. That is, some groups of projects may be uneconomic when considered individually but provide more benefits than costs when considered together. Consumers themselves may often be able to identify a “crowd solution” that is cheaper and generates more economic benefit than when distribution planning decisions are made independently from consumer participation (Keen, et al., 2022). Hence, the proposed market design naturally fits within the transactive energy paradigm.

4.1 Market Transparency

Market transparency requires that existing and potential market participants have convenient access to market pricing information and can easily understand whether their bids and offers are likely to be profitable. Consumers who understand the approximate timing of their requested installation types should be able to gauge how expensive it will be to serve their load or to host their generation capacity. Distribution utilities or third party contractors should be able to examine the market results and understand why their projects were or were not selected over others. The proposed auction design naturally supports this goal since prices are posted publicly and can be derived from the physical limitations of the network.

Our proposed approach applies the same pricing principles as used to derive Locational Marginal Prices (LMPs) in ISO markets, which are generally considered transparent. In contrast to traditional capacity markets, this results in capacity prices that are differentiated by location and by time. In particular, the examples assume three time periods and three nodal locations where end users connect to the distribution grid. A real-world implementation of the proposed market design could be extended to include separate pricing information for each individual distribution network node and each time period or scenario considered in a network planning model. Market transparency requires making these prices available to consumers so that they may be able to judge whether they are likely to benefit from participating in the market by simply looking at the prevailing prices from the last few auction results. Customers wanting to reduce their utility bills may be able to do so by offering DR capacity in the auction that shifts their load out of the high-priced time periods.

There is an inherent tradeoff between the complexity or granularity of the prices and the ease of consumer participation. Regarding locational prices, it could be easier to understand prices that have been aggregated, perhaps a single price for all houses on the same block, in the same neighborhood, or even all locations under the same feeder. Theoretically, single-location pricing will always be the most efficient design, and more aggregation will degrade market efficiency. A real-world implementation would therefore need to consider the practicality and fairness of sending hyper-specific prices to each utility customer, or whether there may be gains from price aggregation that are difficult to model analytically. For example, discussion amongst neighbors may improve price discovery and efficient market entry, but this process could be hampered if each end user receives individualized hosting capacity prices.

Similarly, a market designer would need to consider the amount of temporal granularity to include in the prices. This may depend in large part on the model that the distribution utility uses for planning purposes. We have assumed that the model considers morning, daytime, and evening conditions. These are essentially three independent scenarios in the planning model, and a real-world distribution hosting capacity auction implementation would be free to consider any scenarios the market entity believes is appropriate. However, as more scenarios are considered, there could be difficulty in communicating why some scenarios are priced and others are not, or why a particular installation permit's price depends on one scenario but not another. In the examples provided here, we found that the distribution network pricing was relatively simple since the network was only constrained in the evening. The auction allocates solar PV installation permits at zero cost because solar power generation has no effect on network constraints that are only binding in the evening scenario. The auction also allocates permits for EV chargers and DR. The auction therefore identifies an economic complementarity between these two permit types since DR was able to reduce feeder loads when they became stressed due to new EV chargers.

4.2 Extensions for Additional Products

Another advantage of the proposed distribution hosting capacity auction design is that it is easily extensible to novel products to address consumer preferences and the specific needs of distribution networks. This section notes a few plausible extensions that address the following:

Bi-directional flows

Our examples implicitly assume that power flows in the distribution network are unidirectional from the T&D interconnection to load, but the potential for broader DER integration may change this status quo. Products that consider distribution hosting capacity with bi-directional flows could become necessary to ensure that energy from DERs is delivered to the transmission grid without sacrificing reliability. For example, the proposed auction would identify if a substation upgrade or service to new loads would be required before large amounts of solar PV can be safely installed.

Reliability service level

The above auction formulation and examples assumed that loads are always served at a high reliability level and that demand response capacity is always available. A more generalized framework could allow loads to specify different reliability levels (i.e., hours of curtailment per year) and demand response to specify different dispatch frequencies. Lower reliability load service and higher frequency demand response are two sides of the same coin and effectively provide the same service. Customers who sign up for lower reliability service would have their service curtailed more often, but they would be given a discount via their payment from the auction. These differentiated service levels could be implemented in the auction formulation by adding constraints on the number of hours that a load is served or a demand response resource is dispatched. To avoid equity concerns, this scheme could entail a basic high reliability service for HVAC and refrigeration loads and a menu of reliability options for other loads (e.g., lighting, water heater, appliances). By differentiating the value of different loads, this option would provide an important source of load flexibility to distribution grid operators.

Load shifting

Load flexibility may also require not merely curtailment, but also compensatory load increases in other hours. This consideration could affect not only demand response – e.g., additional heating/cooling if an HVAC system is curtailed – but also the design of EV charger permits. In the example's assumed EV charger permits, EV charging is a "premium" product that allows customers to charge their EV at any time of day. A "managed" EV charging permit could be more economical and would specify that the utility can throttle the EV charging rate during specified hours so long as a guaranteed amount of energy is provided by the end of the charging period. In either case, DR or EV charging, consideration of load shifting can be implemented by adding energy constraints that guarantee a minimum energy level over multiple periods; for example, the energy provided by DR may sum to zero over the course of a day, or the energy provided to an EV charger would sum to the EV's battery capacity. This option would also provide load flexibility to grid operators, but it may offer more convenience to end users who could be assured of energy delivery (rather than curtailment) within specific time ranges.

Network weatherization

Areas that are susceptible to extreme weather may desire to include options for weatherizing the distribution network against possible disasters. For example, network reinforcement to protect against ice storms, snowfall, flooding, high winds, hurricanes, wildfires, or extreme heat may be desirable if the cost of the weatherization upgrade is less than the risk-adjusted damage cost. The market entity in our proposed design may either develop a methodology to estimate a network weatherization demand curve, or perhaps state or local regulatory authorities may require specific weatherization. The proposed auction would ensure that the upgrades meet the requirements at the least cost to consumers.

Extreme weather backup service

As it may not be possible to maintain 100% reliability of the distribution system, the proposed auction design could be extended to plan for energy use during distribution or transmission system outages. Customer-owned solar PV panels, portable backup generators, and other DERs may be able to safely operate to provide a small amount basic service to some customers. Depending on how this emergency service is planned, it may require close supervision by the distribution utility to ensure safety. It could also be used to allocate portable backup generators that would be distributed after severe weather events and could be shared among neighbors. Some customers may request backup service while others may offer a share of an existing generator.

Microgrid operation

Lastly, the proposed auction may also be modified to support microgrid operations. This modification would entail including additional scenarios in the planning model that ensure reliable microgrid operations. As both typical and microgrid operations would be considered simultaneously, this form of planning may be more efficient than when microgrid operations are considered independently.

4.3 Integration with Existing Distribution Planning Processes

As with any policy change, the proposed distribution hosting capacity auction would need to be integrated into existing processes and some consideration given to how to transition from the status quo to the proposed system. This section describes, in very broad terms, how some of the changes required by our proposal would fit into existing processes. We describe a process to initially allocate unused capacity, the inapplicability of the auction to regular maintenance costs, and possible institutional changes that may be needed to support the auction function.

Distribution systems today are typically overbuilt for various reasons; for example, the utility company may need to plan for significant 3-10 year uncertainties or may compensate geographic uncertainty about heterogeneously dispersed load types (e.g., EV chargers) with homogenously dispersed capacity upgrades (Keen, et al., 2022). That is, many distribution systems today may have unused capacity that was built into the network in anticipation of future load growth, which raises a question: how should this excess capacity be treated in the proposed distribution hosting capacity auction?

Excess hosting capacity – that is, capacity that has not yet been allocated via the distribution hosting capacity auction – is presumably currently owned by the distribution utility. This status quo can be easily integrated into the proposed auction system by performing an initial allocation of permits to the distribution utility or to a 3rd party designated by the utility. Assuming these initial permits are held by the utility, the permits can be sold in later auctions, allowing the utility to recover its costs from network construction. This initial allocation could be as simple as translating the utility's planning assumptions into permits (i.e., a kW or kVAR amount at each network location), or the utility may opt to define some other kind of optimal permit allocation. The utility could then offer these permits into future auctions at a price equal to the regulated interconnection costs that they would normally charge today.

Regular maintenance of the distribution network may need to be handled differently than the allocation of permits and construction contracts described above. Once completed, many infrastructure projects require maintenance to ensure that equipment continues to meet its performance specifications. Equipment needs to be replaced once it has met the end of its useful life. However, should a holder of a distribution hosting capacity permit be required to pay for replacement? Similarly, should a permit holder be required to pay for maintenance of the capacity that was already purchased? These considerations lean in favor of applying the proposed auction concept to *new* hosting capacity while treating regular maintenance and replacement the same as what is done today. In other words, regular maintenance costs may still need to be allocated evenly across end-users on a pro rata basis (which could be either per kW, per kWh, or a mix of the two).

A few options could be considered to incorporate more maintenance and replacement costs into the auction. For example, upgrade contracts could be specified such that the contractor is responsible for maintaining installed equipment for a term of, perhaps, 20 years, with the understanding that they may be able to contract maintenance to the distribution utility for cheaper than they could maintain the equipment themselves. Installation permits, similarly, could alternatively be designed with and "end date" that coincides with the expected useful life of network upgrades, allowing future replacement costs to be funded by the sale of new permits.

Consideration should also be given to the institutional structures required to operate the proposed auction and integrate it with current distribution utility operations. We anticipate two main institutional changes towards implementing the proposed auction design. First, our proposed market design may be implemented by and replace the current planning process of an existing distribution utility. Alternatively, a new market entity could be developed to host the proposed auction, and the results of the auction would then be passed along to the existing distribution utility. A short outline of each path is discussed below and is depicted in Figure 2.

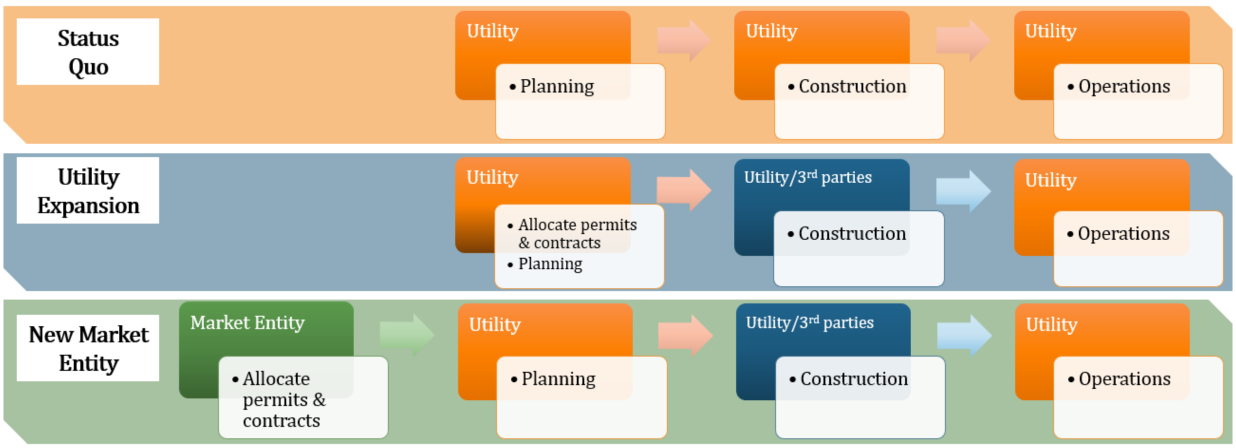

Figure 2. Implementation Pathways

In the status quo, all planning, construction, and operations decisions are made by the distribution utility. This is likely to result in inefficiencies since end-use customers may have few opportunities to participate in the planning process and there may be limited exploration of cheaper third-party options to construct network upgrades.

In the "utility expansion" option, the distribution utility is tasked with running the proposed network capacity auction. This opens up new opportunities for consumer involvement and possible construction contracts awarded to 3rd party contractors. However, there is a significant expansion in the distribution utility's responsibilities, which it may not have the personnel or expertise to accomplish.

The "new market entity" option is the last option depicted in Figure 2. Rather than relying on the distribution utility to perform this new function, it is managed by a new entity that is only tasked with allocating permits and construction contracts via the proposed auction. This entity could be created as non-profit corporation with similar governance as the ISOs, a municipal agency run for public benefit, or a for-profit corporation. Such an entity would hold the auction, allocate permits and contracts, then pass this information along to the distribution utility. The utility would then perform its planning function similarly as it does today, albeit they would primarily check that the auction results are acceptable. Then, the utility would construct necessary upgrades, possibly coordinating with 3rd-party contractors and finally, would operate the distribution system on a day-to-day basis.

These and possibly other pathways to real-world implementation should also be discussed and explored in detail. We leave this task to future work.

4.4 Policy and Equity Support

Having described the proposed auction's formulation, properties, possible extensions, and a path to real-world application, we conclude this discussion section with initial thoughts on why policymakers may want to implement the distribution hosting capacity auction. Many states and municipalities have announced or implemented renewable portfolio standards (RPS) or other similar polices that require energy providers to procure some percentage of their energy from renewable or other clean energy sources. Under the framework proposed above, records of local DER installations would be automatically generated and become available to help verify whether RPS requirements have been met. The auction design would also increase the pool of potential RPS-compliant projects since it engages end users, distribution utilities, and 3rd parties alike to contribute to the distribution network planning process.

With a few small modifications, the auction can also help implement an RPS or similar policy. The auction formulation can be modified to include constraints on the amount or percentage of energy served by different technologies. Of course, any such modification would require careful thought since it may reduce the benefits provided by the auction and could induce revenue insufficiency (i.e., more payments allocated than received). Potential solutions could include minimum offer price rules, higher overhead and administrative fees, or access to public funds.

In addition to helping meet specific policy goals, the proposed auction may also help support broader public initiatives such as encouraging equity among consumers and supporting underserved communities. As proposed, the auction framework allows all end-users of electricity to directly participate in how their energy delivery is planned. End-users who can supply a cheaper alternative to expensive network upgrades would be encouraged to do so and could receive payment for their services. We also compare the proposed auction to existing queue-based approach that assesses projects one-by-one and can result in lengthy project delays and huge cost allocations to whichever project tips past the existing network capacity. By making the interconnection process more efficient, the auction framework could make community-owned solar or similar projects more economically viable by ensuring a more equitable cost allocation. This level playing field could be enjoyed by as many end-users that participate in the auction.

5.0 Conclusion

This whitepaper proposes a distribution hosting capacity auction that applies concepts from transactive energy to improve distribution network planning decisions. The cornerstone of the market design is an auction that allocates permits for end-use customers to modify their usage profile (e.g., by installing PV panels, EV chargers, or DR controllers), and construction contracts for utilities or 3rd party companies to upgrade network components.

The result of the auction is a set of planning decisions that efficiently maintain network reliability and support the requests of end-use customers. Our examples show various properties of the marginal pricing scheme used by the auction: requests that do not interfere with network constraints are allocated at zero cost, requests are denied if they cost more to serve than the consumer benefits, and all consumer requests and potential network upgrades are considered simultaneously so that the most efficient planning decisions can be made (e.g., by supporting customer requests with complementary requests instead of costly upgrades). Numerical results indicate that the auction prices may be supporting prices, that is, the auction's results satisfy individual value and profit maximization conditions for participants, but theoretical confirmation of this result remains to be proven as we continue to develop the market design.

Finally, the whitepaper discusses various modifications to the proposed market design that address broader conditions and preferences that may be relevant to distribution systems and end-users. These conditions and preferences include bi-directional network flow, load flexibility, variable reliability service levels, network weatherization, backup service, and microgrid operations. While discussion of these aspects is brief, further development may be an import area for future work and would help build the case for implementing the proposed distribution hosting capacity auction. Towards that goal, the shorter-term next steps should include performing a larger scale case study to supplement the illustrative examples contained here. Further case studies could be used to examine if proposed auction, with minor modifications, can help identify and support cost effective plans to satisfy regional, state, or local renewable portfolio standards or other similar policy mandates. The proposed auction also provides a bottom-up approach to distribution network planning, which may allow more equitable consumer engagement.

6.0 Acknowledgements

This project was supported by the Department of Energy, Office of Electricity, Grid Controls and Communications Program. We would also like to thank Abhishek Somani, Brittany Tarufelli, Jesse Holzer, and Hayden Reeve for their valuable insights and guidance during the development of this whitepaper.

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