Distributed Utility 2.0

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April 30, 2019

The original incarnation of the distributed utility ("distributed utility 1.0") dates back more than two decades.[1] This notion, of an electric distribution utility that would plan for, invest in, and operate distribution-level resources for the benefit of its customers, was an idea ahead of its time.

More recently, a combination of technological innovation, customer choice, big data, rising retail rates, resiliency concerns, and state policy are driving the electricity industry toward new a distributed utility paradigm — "distributed utility 2.0." This new paradigm has far-reaching implications for the planning, operation, and pricing of the electric distribution grid that are still not fully explored.

This paper provides a long-term vision for future distribution utilities and the distribution grid, focusing on three areas: (1) planning and interconnection; (2) operations and market services; and (3) rate design. The vision presented in this paper is not intended to be *the* vision but rather *one* possible vision. The paper aims to generate discussion rather than to prescribe solutions.

The paper is organized around the three areas described above. For each area, we provide historical perspective and a vision for a distributed utility 2.0 paradigm in which active distributed energy resources become an integral part of electricity systems.

Transitions to more active distribution systems will likely be gradual, often incremental, and uneven among jurisdictions. The conclusions offer thoughts on near-term steps that could enable progress toward long-term visions. As part of these transitions, it is important to bear in mind the promise of a more active demand side: more competitive electricity markets, greater customer choice, lower environmental impact, more flexible operations, higher reliability, and enhanced resiliency.

Definitions

As with any changing industry, terminology surrounding distributed energy is often ambiguous. For clarity, this paper begins with a few key definitions.

The term **'distributed utility'** is used broadly in this paper to refer to any electric distribution utility that manages distributed energy resources on its distribution network. In the future this will, at some level, include all distribution utilities. Distributed utilities can be municipal utilities, cooperative utilities, investor-owned vertically integrated utilities, investor-owned default service providers, or investor-owned "wires only" transmission and distribution utilities. Differences among utilities have important implications for the distributed utility's roles in planning and investment, operations and markets, and rate design, as discussed below.

'Distributed energy resources' refer broadly to resources that are located within the distribution system, including: behind-the meter generation and energy storage; generation and energy storage

[1] See for instance, Roger Pupp, 1996, *Distributed Utility Penetration Study*, EPRI-TR-106265, Palo Alto: EPRI.

connected to the primary distribution system; and automated and controllable loads. **'Customer-sited resources'** refer explicitly to resources that are located behind a customer meter. **'Distribution-level resources'** refer to resources that are connected to the primary distribution system. In discussing distributed energy resources, it is often more precise and accurate to distinguish between resources that can export to the distribution system (generation, storage) and demand response.

'Distributed energy customers' refers to customers that install distributed generation, distributed storage, and/or demand response capabilities. **'Self-generating customers'** refers more narrowly to customers that have the ability to supply all or part of their own energy needs through generation or storage. **'Wholesale customers'** refers to customers that buy and sell power at wholesale rates.

'Local distribution area' refers to a distribution network behind a sub-transmission-level meter. Each local distribution area is an interface between an independent system operator, which operates the high voltage transmission system, and distribution system operators, which operate lower voltage distribution systems.

Planning and Interconnection

Historical Perspective

What currently falls under the broad rubric of "distributed energy resources" was historically a collection of individual utility programs: energy efficiency and demand response programs operated by utilities or third-parties and often mandated by state lawmakers and regulators; a subset of long-term offtake contracts with qualifying cogeneration facilities under the Public Utilities Regulatory Policy Act (PURPA); and distributed generation supported by net energy metering (NEM) programs.

Despite the complexity of regulatory rules around these programs, they were typically discrete and largely separate from utility procurement and investment processes. Program size was driven primarily by a mixture of legislation and regulation: targets and budgets for energy efficiency and demand response programs, avoided costs for PURPA contracts, and caps on NEM programs. Cost-effectiveness evaluation frameworks for these programs were often based on a relatively coarse (temporal, spatial) measure of utility avoided costs. Subject to program limits, utilities were required to interconnect eligible generating resources.

In the 2010s, a confluence of technology, policy, and demographic trends have driven a reconsideration of utility programs and planning for what were increasingly seen as a holistic category of resources — distributed energy resources. In proceedings like New York's Reforming the Energy Vision (REV) and California's Distribution Resources Plan (DRP), utilities were required to expand the scope of their distribution planning to enable higher penetration of distributed energy resources and procure distributed energy resources that could cost-effectively defer or avoid investments in distribution infrastructure, often as part of or in parallel with efforts to modernize the grid. Regulators in Oregon, California, and Hawaii began to require utilities to incorporate distributed resources in their bulk procurement and investment planning as resources rather than simply as fixed load modifiers. Improvements in data collection and management began to create new possibilities for utility forecasting and planning.

The growing popularity of distributed solar and battery storage revived interest in customer choice. Falling costs for these resources raised the prospect that customers could adopt distribution-level generating resources outside of utility programs, leading to a competitive “grid edge” and a potentially large number of resources interconnecting to distribution systems.

Anticipating, or in some cases in response to, utility efforts to slow interconnection, regulators began to reform and refine interconnection policies for the distribution grid, requiring clear timelines for interconnection and rules for allocating the costs of any upgrades triggered by new resources. In states like California, Minnesota, and New York, regulators required utilities to regularly undertake and publish hosting capacity analyses, providing customers and third parties with information on where the distribution system could accommodate new resources without upgrades. However, efforts to reform interconnection rules stopped short of requiring non-discriminatory access to the distribution system.

Developments in distribution planning and interconnection led regulators in some states to begin to order distribution utilities to develop more formal, open distribution planning processes. Again, however, requirements for transparency and process stopped short of resembling those for ISO transmission planning.

This general trend, toward more integrated, transparent distribution planning and open access interconnection, is set to continue, enabled by continued improvements in technology and customers’ growing desire for choice. Questions remain about the scope of integrated distribution planning, how distribution open access could be implemented, and linkages between distribution planning and operations and retail rates.

Vision

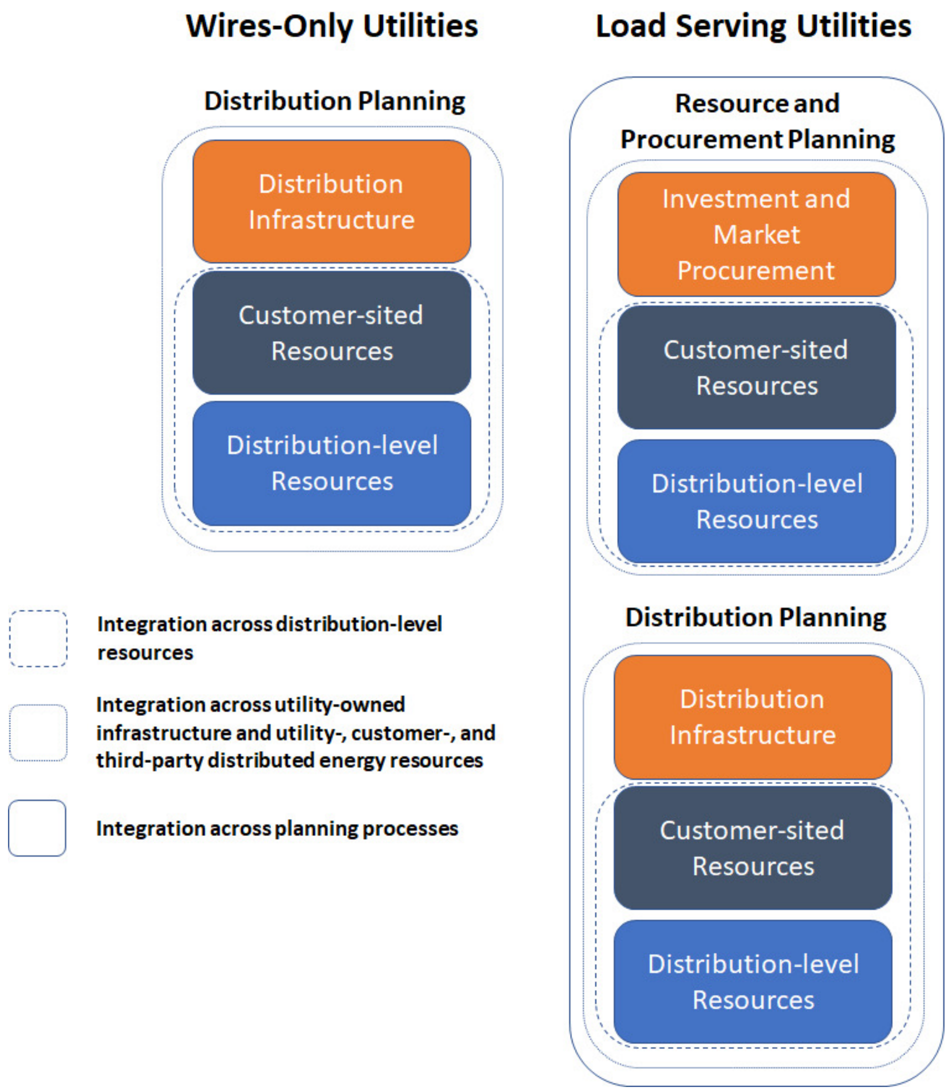
Distributed utility 2.0 is an integrated distribution service planner and open access provider.

Distribution utilities integrate planning for distribution services and distribution infrastructure across multiple dimensions:

- Across multiple distributed energy resources, including customer-sited resources (behind-the-meter generation, behind-the-meter battery and thermal storage, EVs, demand response resources, energy efficiency) and distribution-level resources (generation and storage connected to the primary distribution system) that may be owned by customers, third parties, or utilities;
- Across distribution infrastructure and distributed energy resources, through non-wires procurement;
- Across planning processes, including distribution planning, procurement planning, and resource planning.

The scope of integrated planning varies across different kinds of utilities (Figure 1). Wires-only utilities integrate planning for multiple distributed energy resources into their distribution infrastructure plans. In addition to integration in distribution plans, default service providers and vertically-integrated utilities also integrate distributed energy resources into their procurement and resource planning.

Figure 1. The Scope of Integrated Planning Differs for Wires-Only and Load-Serving Utilities

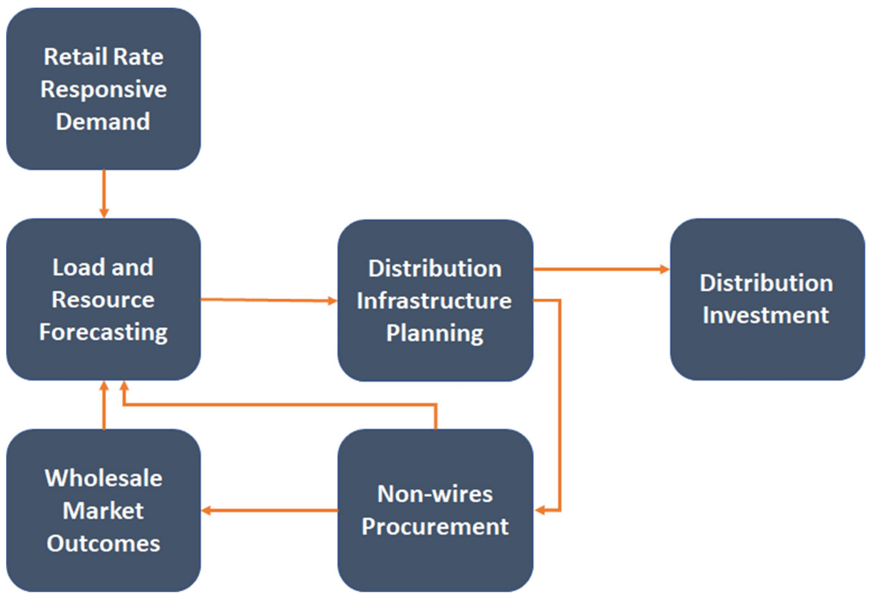


In distribution planning, distributed utility 2.0 regularly procures distributed energy resources to provide non-wires solutions to distribution infrastructure needs. Regulatory incentives enable utilities to earn a return on investment on non-wires solutions procurement that is comparable to what they earn on conventional distribution infrastructure investments. Utilities use integrated analysis tools with granular temporal and spatial resolution to procure a least-cost portfolio of non-wires resources, including energy efficiency, demand response, energy storage, and distributed generation.

Where it serves load, distributed utility 2.0 incorporates distributed energy resources into its investment and procurement planning as a potential resource. In valuing distributed energy resources, utilities incorporate their distribution system value, which links distribution planning with bulk system resource planning and procurement. Resource and procurement plans also capture the potential value of distributed energy resources in reducing a range of risks: load forecast, technology cost, fuel price, and regulatory compliance.

For infrastructure planning, utility load and distributed energy resource forecasting tools use customer interval meter data, have high spatial and temporal granularity, and incorporate machine learning algorithms. Long-term load and resource forecasting for infrastructure planning integrates retail rate-responsive demand (see Rate Design) and wholesale market outcomes (see Operations and Markets) and captures potential feedbacks from non-wires procurement through coordinated and iterative planning processes (Figure 2). Wholesale markets affect the net costs and the value proposition of non-wires resources, and to a lesser extent non-wires procurement may affect wholesale markets; non-wires procurement impacts load and resource forecasts.

Figure 2. Integrated Load and Resource Forecasting and Distribution Infrastructure Planning



For investor-owned and potentially municipal utilities, distribution utility 2.0 plans for an open access distribution network under an open access distribution tariff (OADT). The OADT provides rules for non-discriminatory access to the distribution system, including how any reliability-related upgrade costs triggered by interconnecting resources are to be allocated. However, it does not require, nor does it guarantee, that these resources will be fully deliverable or fully dispatched. Resource owners and aggregators absorb deliverability, dispatchability, and other market risks. As part of their distribution plans, utilities make "economic" investments that reduce congestion on the distribution system based on benefit-cost analysis.

Like their role for the transmission network, open access tariffs at the distribution level provide clear, documented rules on access and interconnection, roles and responsibilities, operational processes, settlement and billing, and market oversight and dispute resolution (Table 1). Through these rules, OADTs create an important link between utility investment planning and the reliable, least-cost operation of the distribution system.

Table 1. Core Questions for Designing Open Access Distribution Tariffs

Access and interconnection	• What kinds of resources are eligible to access the distribution system on a non-discriminatory basis?

	• What kinds of entities are eligible to schedule resources on the distribution system and what kinds of certification do they require? • What are credit requirements for market schedulers and retail providers and how will compliance be reviewed and enforced? • What standards and testing requirements must new resources meet to interconnect to the distribution system? (Specific requirements described in a separate pro forma interconnection agreement) • How much must new resources pay to interconnect, and what is the basis for this payment?
Roles and responsibilities	• What are the rules of conduct for participants and scheduling coordinators? • What are rules and standards of performance for distribution system operators? • What are rules governing the relationship between distribution utilities and distribution system operators?
Operations	• What market (bid-based, tariff-based) products does the distribution utility offer? • What are forecasting requirements and standards of performance for market participants and the distribution system operator? • What are the procedures for scheduling and dispatch? • What are models and estimators are used by the distribution system operator? • What is the relationship between the distribution system operator and the ISO? • What procedures must the distribution system operator follow during emergencies and how do emergencies affect commercial settlement? • What market information does the distribution system operator make public? • In bid-based markets, are market participants' bids mitigated and if so on what basis and how?
Settlement and billing	• What are settlement principles? • How do the distribution utility and distribution system operator settle accounts for market participants? • What fees and charges are market participants obligated to pay to the distribution utility and distribution system operator?
Market oversight and dispute resolution	• Which organization settles disputes between market participants and distribution utilities and distribution system operators, and through what process? • Which organization is responsible for market monitoring and oversight?

To support its OADT, distributed utility 2.0 undertakes a regular, formal, transparent distribution planning process, overseen by state regulators.

Operations and Markets

Historical Perspective

Distribution utilities have not historically been "system operators" in the same sense that this term is used for the high-voltage transmission system. Historically, distribution utilities interconnected distributed resources on a case-by-case basis and only changed the operation of these resources when needed to maintain reliability. Distributed generation was typically embedded within utility load forecasts and often net metered. Distribution utilities curtailed interruptible load and shifted load through demand response programs, but demand response was more widely used in wholesale capacity markets than as a resource in distribution systems.

The design and management of the electric distribution system mirrored this model of the distribution utility as passive manager rather than active coordinator. Distribution systems were designed for one-way power flow; utilities had limited visibility into voltage and flow conditions and equipment status below a substation level; and utilities used dedicated equipment rather than distributed resources to manage distribution voltages and loading.

More significant changes in this paradigm began in the 2010s, driven by a mix of policy and technological change. Often in parallel with proceedings to modernize the distribution grid, some state regulatory commissions directed utilities to take proactive steps to integrate distributed energy resources, requiring more visibility and active control over these resources. In New York, regulators ordered utilities to develop plans for distributed system platforms that would, *inter alia*, better align the operation and compensation of distributed energy resources. Regulatory commissions stopped short of requiring utilities to create functionally unbundled distribution system operators (DSOs).

Despite the beginnings of a shift toward more active operation of distributed generation and storage, these resources were still wedged between utility programs and wholesale operations. Prices and incentives often had little to do with utility or ISO operating needs. For instance, during system-wide overgeneration events a NEM tariff would compensate distributed PV owners at a full retail rate, providing no incentive for re-dispatch or storage. Some regulators began to explore wholesale rates for distributed generation and storage, led by New York's Value of DER (VDER) tariff. ISOs realized that, without better alignment between prices and operations, higher penetration of distributed generation and storage could impact bulk system reliability.

To address this concern, ISOs began considering rules to allow third-party aggregators of distributed energy resources to participate directly in ISO markets. For instance, the California ISO (CAISO) amended its tariff in 2017 to encourage direct participation of "distributed energy resource providers." ISO efforts to assert more control over distributed energy resources raised a fundamental question: should the ISOs or distribution utilities schedule and dispatch distributed energy resources?

Although distributed PV was often a focus of ISO operational concerns, growing interest in distribution-level storage created a clearer tension between ISO and utility control of distributed energy resources. Regulators in New York began to talk about "dual participation" in "distribution markets" and wholesale markets, though distribution markets remained an amorphous concept and the vision of dual participation was limited to "rules-based" coordination between distribution utilities and the New York ISO (NYISO).

These developments all illustrate a gradual trend toward greater operational control of distributed energy resources and more active management of the distribution system. Questions remain about the role of DSOs vis-à-vis ISOs and how distribution operations can be coordinated with wholesale operations.

Vision

Distributed utility 2.0 is a distribution system operator and market service provider.

What this statement means varies by context. For investor-owned utilities in organized markets, distributed utility 2.0 provides open access to the distribution system under a distribution tariff and wholesale market coordination services. For member-owned utilities, distributed utility 2.0 provides access based on member agreed-upon rules and may directly offer or contract for market coordination services. Municipal utilities choose either the open access or the rules-based model.

For open access distribution networks, distribution utilities have functionally unbundled DSOs; DSOs may also be a separate, independent organization. DSOs ensure comparable service for resources owned by customers, third parties, and utilities and for imports at the DSO-ISO interface. State regulators monitor and enforce open access rules.

In all cases, DSOs take a more active approach to the security-constrained economic dispatch of distributed energy resources than its predecessor. On the distribution system, security-constrained dispatch refers either to (a) the dispatch of distribution-level resources that minimizes the total cost of serving load (or, maximizes total surplus) in a distribution area or (b) the dispatch of distribution-level resources according to customer- or aggregator-preferred service levels, subject to security and flow constraints in both (a) and (b). DSOs dispatch three kinds of distributed resources: generation (PV, wind, gas microturbines, CHP), energy storage (battery, thermal), and dispatchable loads.

Interconnected distribution-level generation and storage resources are subject to DSO control, but distributed energy customers voluntarily choose whether to participate in the DSO's economic dispatch. DSOs take either a tariff-based or a bid-based approach to scheduling and dispatching distributed energy resources. Table 2 highlights the differences between these two approaches.

Table 2. Tariff-Based and Bid-Based Approaches to Scheduling and Dispatching Distribution-Level Resources

	Tariff-based	Bid-based
Distribution charge	Differentiated by service level	Not differentiated by service level
Dispatch	Determined by service level	Bid-based
Settlement	Regularly updated wholesale tariff	Wholesale market-based passthrough
ISO coordination	DSO sends day-ahead net demand forecast to ISO	DSO sends day-ahead and real-time net demand forecasts to ISO; ISO sends 5-minute "dispatch" instructions to DSO

Distribution energy resource participation in capacity markets	Tariff-based	Market-based
Distribution energy resource participation in ancillary services (A/S) markets	None	Bid-based

In both the tariff-based and the bid-based approaches, DSOs act as schedule aggregators, operators, and settlers, subject to the terms of a distribution tariff or market rules. Both approaches are consistent with the "layered optimization" model proposed by Kristov et al.[2] and the need for distribution utilities to ensure that the operation of generation and storage resources exporting to the distribution system is subject to distribution-level security constraints. With some exceptions under the tariff-based approach, lower voltage resources and service providers no longer participate directly in ISO markets, but in the bid-based model there is very little operational difference between direct and indirect participation in those markets.[3] This layered optimization approach balances organizational efficiency, reliability needs, and economic efficiency.

Tariff-based Approach. Under the tariff-based approach, distributed energy customers differentiate themselves by service level — for instance, firm and non-firm. Customers with firm distribution service pay a higher distribution charge in exchange for priority service, which means that they are only curtailed during system emergencies. Non-firm customers pay a lower distribution charge, but their resources may be curtailed on a pro rata basis as needed to relieve distribution system constraints. Distributed energy customers providing non-wires solutions must purchase firm distribution service or be fully dispatchable by the DSO.

Before the operating day (day-ahead), DSOs submit 15-minute bids to an ISO for their next day's net demand at the substation meter connecting their service territory to the high voltage transmission system. Net demand refers to load minus generation and can be negative when a local distribution area is exporting power to the transmission system. DSO net demand bids may be self-schedules (quantity, no price) or have price responsive portions. DSOs may economically dispatch utility-owned resources and resources on behalf of their customers. DSOs develop their day-ahead schedules based on forecasts of metered net demand, availability of economically dispatchable resources, and distribution constraints. Schedules for distributed energy customers are captured within day-ahead forecasts and are effectively self-schedules within the DSOs' day-ahead net demand bids.

In cases where an ISO must curtail a DSO's net exports to the transmission system, the ISO sends a dispatch instruction to the DSO and the DSO responds by curtailing interruptible (non-firm) customers on a pro rata basis. The DSO is levied an uninstructed dispatch penalty if it does not respond.

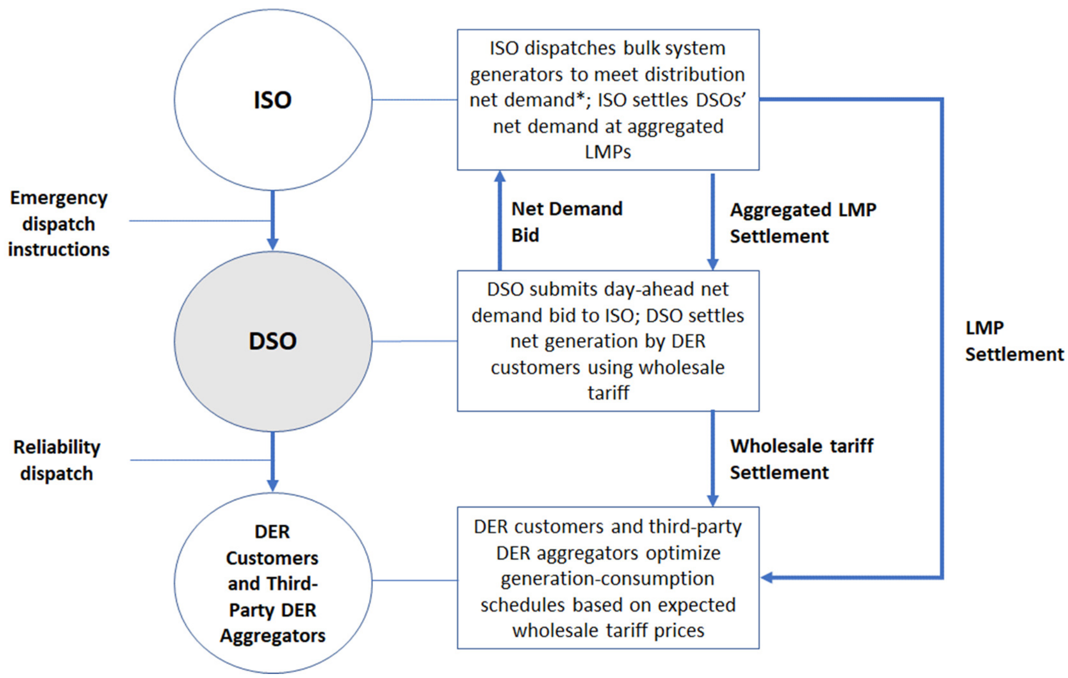
Distributed energy customers are compensated for the wholesale energy and capacity they provide using a regularly-adjusted wholesale tariff like New York's VDER tariff. Wholesale energy market

[2] See Lorenzo Kristov, Paul de Martini, and Jeffrey D. Taft, 2016, "Two Visions of a Transactive Electric System," http://resnick.caltech.edu/docs/Two_Visions.pdf.

[3] There may be material differences between ISOs and DSOs in terms of forecasting capabilities, which would influence market outcomes.

settlement is based on aggregated locational marginal prices (LMPs), though distributed energy customers can opt to be settled by the ISO at nodal LMPs.[4] Any utility capacity payments to distributed generation and storage are based on distribution utility rules and at tariff-based prices, though non-utility retail providers and demand response providers still participate directly in ISO capacity markets. Distributed energy customers and third-party aggregators optimize their generation and loads relative to utilities' wholesale tariff.

Figure 3. Energy Market Dispatch, Scheduling, and Settlement Under the Tariff-Based Approach



** The ISO also dispatches bulk system generation to meet net demand at the transmission voltage level; the focus in this figure is on the distribution system*

This tariff-based approach allows self-generating customers to indirectly supply other customers within a load aggregation area. For instance, a self-generating customer that is exporting to the grid will reduce a load aggregation area's day-ahead (forecasted) or real-time (metered) demand, which means that load serving entities are effectively procuring energy from that customer rather than from the bulk system. The self-generating customer is paid the tariff price, which is linked to an aggregated LMP, and non-generating customers pay the aggregated LMP. Higher levels of self-generation will reduce either day-ahead or real-time prices, flowing through to all customers.[5]

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[4] In principle, there would be little difference between the DSO and the ISO settling these opt-in customers, though if the DSO does not settle most of its customers on disaggregated LMPs it is unlikely to have the requisite information systems to do so.

[5] How this would play out in practice depends on forecasting technology. If load serving entities are able to incorporate customer-sited generation in day-ahead forecasts, the aggregate day-ahead demand bid for the load aggregation area will be lower and thus aggregate LMPs will be at least marginally lower. If day-ahead forecasts do not include customer-sited generation, real-time metered demand will be lower as a result of self-generation, and as a result real-time prices and settlement will be lower. Load and LMP aggregation dampens this effect, and

Bid-based Approach. Under the bid-based approach, larger distributed energy customers or third-party aggregators submit day-ahead and real-time net energy demand bid curves to DSOs. Distributed energy customers that do not submit economic offers can choose to self-schedule as price takers or have the DSO economically dispatch their resources on their behalf. Priority on the distribution system is determined by these economic bids rather than service priority and distribution charges. If a DSO runs out of economic bids and still has congestion on a feeder or substation, it curtails generation and storage on a pro rata basis.

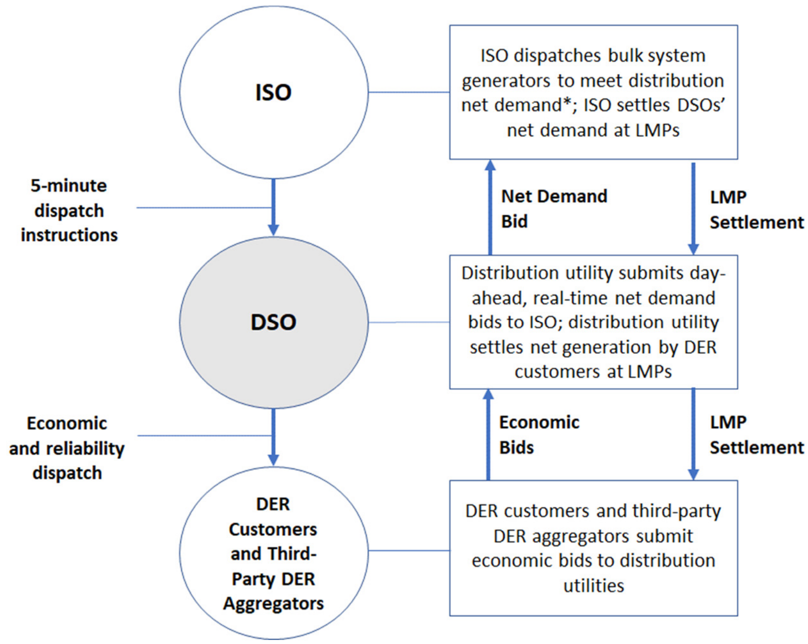
DSOs incorporate economic energy and A/S bids from customers and aggregators into day-ahead and real-time security-constrained forecasting and economic dispatch processes that match the timing of ISO market processes. Day-ahead, DSOs submit aggregate 15-minute net demand bids and A/S bids for each of their distribution-transmission interfaces to an ISO. Using updated forecasts, DSOs submit aggregated 15-minute or 5-minute net demand bids in the real-time market.

Allowing loads to bid into real-time markets departs from current practice, where ISOs clear real-time markets with their own 5-minute load forecasts and use frequency (regulation) reserves and automatic generator control systems to cover imbalances within 5 minutes. Replacing real-time market ISO forecasts with DSO forecasts requires the ISO to incentivize market participants to ensure that their intra-hour schedules are balanced or, phrased differently, that their real-time net load forecasts are accurate.

The ISO sends 5-minute dispatch instructions to DSOs, based on the ISO's security-constrained economic dispatch. The ISO settles energy imbalances at real-time prices and allocates frequency reserve costs to DSOs based on the deviation between their scheduled and metered net demand. DSOs settle net energy demand for distributed energy customers at the day-ahead and real-time LMPs at the corresponding substation node, allowing these customers to take a more active role in congestion management. LMP settlement requires much more sophisticated and data-intensive settlement and billing systems, relative to the tariff-based approach.

means that self-generating customers indirectly sell within an aggregation area rather than a local distribution area.

Figure 4. Energy Market Dispatch, Scheduling, and Settlement Under the Bid-Based Approach



** The ISO also dispatches bulk system generation to meet net demand at the transmission voltage level; the focus in this figure is on the distribution system*

Distributed energy resources participate in ISO capacity markets indirectly through their LSEs. Changes in distributed energy customers' net loads are incorporated into LSE capacity obligations. Some or all LSEs provide incentives to customers to reduce or shift net load, reducing LSE obligations. Schedule coordination between LSEs and DSOs is accomplished through economic bids. The challenge of managing capacity markets with higher penetrations of distributed capacity resources, and the increased price responsiveness from higher levels of distributed energy resources, prompts some ISOs to shift to energy-only markets with scarcity pricing.

Monitoring and mitigation of market power by large customers or aggregators is more important under the bid-based approach, and distribution tariffs have clear rules for dealing with anti-competitive behavior.

Incorporation of customer and aggregator economic bids effectively allows DSOs to facilitate trade among distribution customers. For instance, if customers with net generation are willing to provide energy for less than the wholesale LMP, DSO net demand will clear at a lower level and this distributed generation will supply other customers within a local distribution area. Net consumers pay DSOs and DSOs pay net generators at the LMP. In cases where DSOs are net exporting to the transmission system, there may be a divergence in marginal costs between the distribution and transmission systems, but the benefits of further disaggregation of LMPs to the distribution system is found to be not worth the cost.

Rate Design

Historical Perspective

In the 1960s, the electricity industry began an intensive debate over the merits of average cost and marginal cost pricing, and, in the latter case, short-run versus long-run marginal cost pricing. Average cost pricing followed an accounting philosophy with an emphasis on recovery of prudent utility costs. Marginal cost pricing followed an economic philosophy and emphasized economic efficiency, while ensuring a fair opportunity for full cost recovery.

In practice, average cost pricing prevailed across most of the U.S., and, in cases where marginal cost pricing was applied, long-run marginal cost pricing prevailed over short-run marginal cost. This preference for long-run costs meant that utility retail rates were often not time-differentiated, which explicitly or implicitly rested on an assumption that customers were unable or unwilling to respond to short-run price signals. Larger customers paid demand charges, based on peak demand usage, but most costs were recovered through volumetric ($/kWh) rates. The rationale for volumetric rates was to provide appropriate incentives for conservation, based on the long-run costs of generating and delivering electricity.

To allocate costs across customers, utilities used, and regulators approved, billing determinants that assigned costs to different customer classes based on cost causation but resulted in significant cross-subsidies within customer classes. Regulators recognized that rate design involved tradeoffs and sought to make these explicit in objectives and principles to guide and govern ratemaking. Utilities generally engaged with, and offered choice to, customers through programs rather than through rate options.

Early electricity industry restructuring efforts in the 1990s envisioned that retail competition would replace regulated retail ratemaking. Competitive retail providers would be fully exposed to marginal generation costs and would pay separate regulated delivery (transmission and distribution) charges and customer charges levied by distribution utilities.

To a large extent, this vision of a fully competitive retail sector did not materialize: only a limited number of states, and most notably Texas, embraced full retail competition. Nevertheless, policies enabling full or limited direct access in some states, combined with the establishment of open access transmission rules and the creation of ISO-operated balancing markets, brought generation costs for larger customers more in line with short-run marginal generation costs. Regulators also began to experiment with time-differentiated rates for bundled customers, through opt-in rates.[6]

In the 2010s, distributed PV, typically on net energy metered rates, collided with this average cost world. Utilities and regulators in states like California and Hawaii abruptly discovered that customer-sited generation could be a form of retail competition. Under average cost-based rates with net energy metering, this competition was not simply for the generation portion of utility services but also for transmission and distribution services. The prospect of cost-competitive customer-sited energy storage raised the possibility that, in the future, customers could use more sophisticated means to arbitrage utility rates.

At the same time, lawmakers and regulators began to consider policies to support “electrification” in the transportation and buildings sectors, as part of state climate policies. The potential introduction of a significant amount of high-current vehicle charging and heat pumps on secondary (low voltage) distribution systems had the potential to overload existing distribution equipment, without more active strategies to encourage load shifting. If well-managed, transportation and building electrification offered the promise of lower rates through higher capacity utilization.

[6] In some cases, such as in Arizona, these experiments predated electric industry restructuring.

Regulators struggled to find rate designs that preserved customer choice, encouraged economically efficient self-generation and consumption, enabled utilities to recover their prudently incurred costs, and met thresholds for stability and simplicity. The industry struggled with foundational questions: Would new rate designs alone adequately address the challenges that customer-side competition had created for traditional ratemaking, or should regulators rethink the utility cost-of-service model? Should new rate designs apply to all customers or only distributed energy customers? Should rates for distributed energy customers be mandatory or voluntary?

Although there was growing consensus that customers could respond to time-differentiated prices, the question of how to allocate time-invariant costs — generation, transmission, and distribution capacity — remained. Questions around allocation of these costs reignited long-dormant debates over short-run versus long-run costs as the basis for rates. For instance, the hourly marginal costs of distribution service will be concentrated in a limited number of hours each year, but effective marginal cost-based, dynamic pricing for distribution services could lead to short-run cost under-recovery for utilities as customers economically bypass distribution charges.

Initial approaches to addressing rate design challenges varied across states. Some states explored wholesale tariffs for self-generating residential and small commercial customers. In other states, regulators began to explore mandatory time-of-use rates and, in some cases, time-differentiated delivery charges, for residential and small commercial customers. Evidence from a growing number of pilots suggested that technology could significantly improve customer price response.

These developments illustrate a trend toward greater time-differentiation of both supply (generation, in some cases transmission) and delivery (distribution, in some cases transmission) rates, both to incentivize customers to make efficient investment decisions in distributed energy resources and to encourage load shifting. Questions remain about future rate designs, their application to different kinds of customers, and the integration of price-responsive retail demand into planning and operations.

Vision

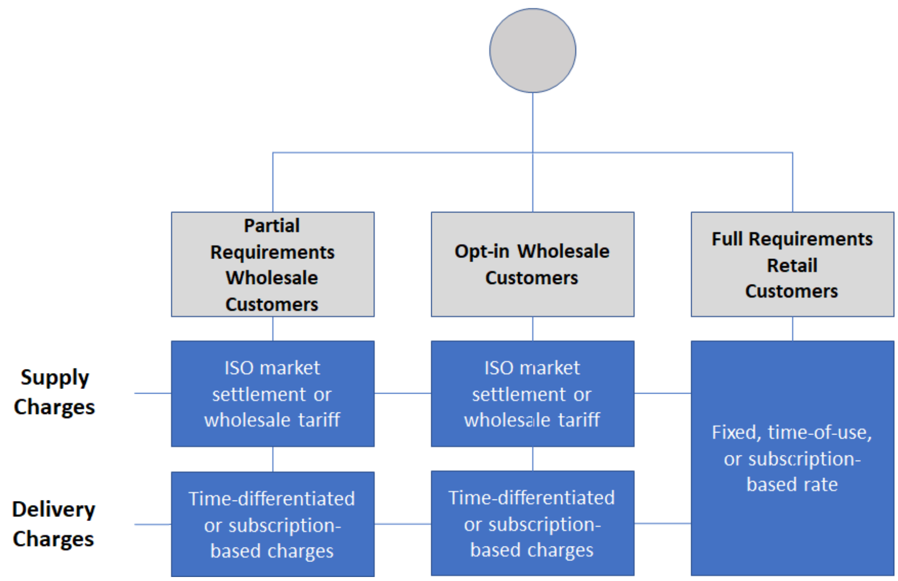
Distributed utility 2.0 provides wholesale and retail pricing that maximizes value, flexibility, and choice for its customers.

As they do today, ratemaking responsibilities vary across different kinds of distribution utilities. Distribution utilities that do not serve load only set distribution rates and, in some cases, transmission rates and customer charges for retail providers. Utilities that serve load also set rates for generation (supply).

Future rate designs differ from contemporary designs in two primary respects. First, a larger number of distribution-level customers take service on wholesale rates. Second, unlike the predominantly flat, volumetric distribution delivery charges of today, future delivery charges are time-differentiated and/or quantity-limited.

Despite differences between competitive retail providers and load serving distribution utilities, their rate structures converge. Both offer three categories of rates that apply to three different kinds of customers: (1) wholesale customers, (2) opt-in wholesale customers, and (3) retail customers. Wholesale customers are self-generating, partial requirements customers that export to the distribution system. Opt-in wholesale customers do not export to the distribution system but can benefit from and choose to be settled at wholesale energy prices. Retail customers are full requirements customers, with a retail provider or a utility supplying their full energy needs (Figure 5).

Figure 5. Rate Structures for Three Categories of Customers



Wholesale customers, whether by designation or opt-in, may be settled using wholesale tariffs or market prices, but in either case their supply and delivery rates are unbundled. For retail customers, retail providers and utilities offer a range of options, from fixed (flat) supply tariffs to more time-differentiated tariffs. As they do today, fixed tariffs require retail providers or utilities to absorb more supply cost risk, and customers pay a premium for these rates as a result.

Delivery — transmission and distribution — charges for wholesale customers and retail providers are time-differentiated and/or quantity-limited, though the approach to time differentiation varies across customers, providers, and jurisdictions. These delivery rates are sophisticated and complex, reflecting a high degree of automated and controlled customer response to prices. In cases where DSOs allow self-generating customers to purchase firm distribution rights, described in the previous section, part of the distribution system is paid for by these customers.

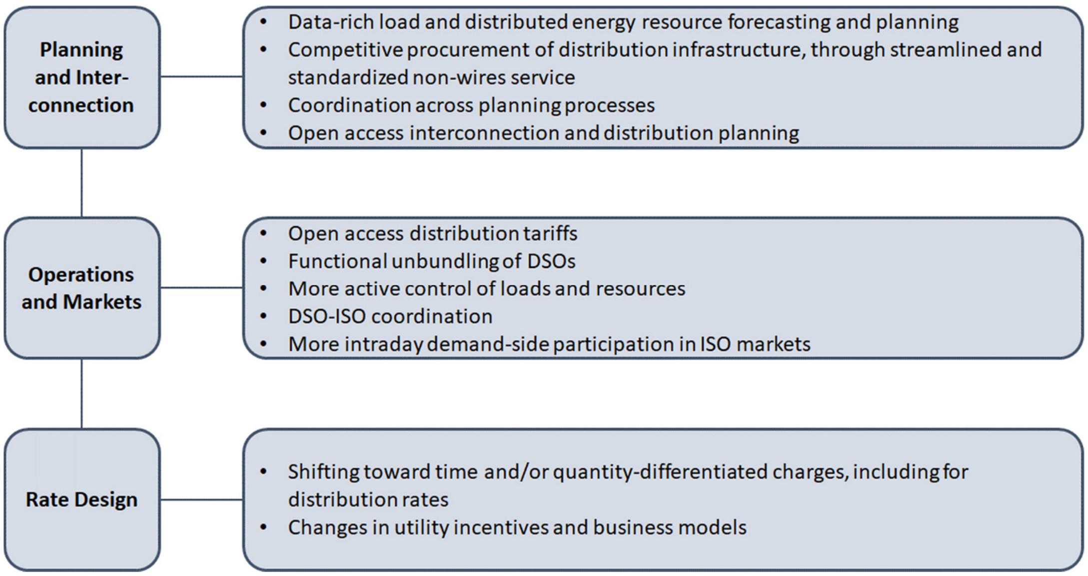
Through a combination of wholesale markets (previous section) and rates, customers play an active role in distribution and bulk system reliability by reducing and shifting loads to avoid overloading, balance short-term imbalances, and respond to contingencies. Utilities and DSOs use advanced forecasting tools to integrate retail rate-driven price response into long-term capacity planning and short-term operations. These forecasting tools incorporate interval meter data, clustering techniques, and machine learning to reduce weather-driven and price-driven forecast error.

Changes in distribution rate design change incentives for distribution utilities. However, different jurisdictions continue to use different approaches to regulating utility rates, cost recovery, and incentives, with some jurisdictions refining or moving toward performance-based regulation and others retaining a more traditional cost-of-service model.

Conclusions: High-Priority Areas for Near-Term Progress

This paper describes one possible vision of the future distributed utility and distribution system. Alternative visions will differ in specifics, but they will likely share common themes, illustrated in Figure 6.

Figure 6. Common Themes for the Distribution Utility and System of the Future



These common themes facilitate a conversation on areas in which utilities, regulators, and stakeholders can make incremental near-term progress in enabling future distribution utilities and systems. We argue that the most important five of these areas include:

- *Advanced distribution planning*, focusing on developing the process coordination, data collection and management, analytical tools, and cost-benefit frameworks needed to enable least-cost investments in future distribution systems;
- *Distribution open access tariffs*, focusing on identifying an acceptable division of regulatory authority between federal and state regulators over wholesale transactions on the distribution system and developing pro forma content for tariffs;
- *Wholesale market designs for DSOs*, focusing on developing DSOs and their capability for security-constrained economic dispatch, and on design changes in wholesale markets that enable more active intra-hour participation by DSOs while still maintaining adequate available capacity;
- *DSO-ISO coordination*, focusing on developing the market protocols, information systems, control and telemetry, and settlement systems for DSOs and ISOs to coordinate transactions at the distribution-transmission interface;
- *Rate designs for flexibility*, focusing on new rate designs that accurately and fairly compensate customers for the flexibility that they provide to the distribution and transmission systems.