DUAL PROGRAM PARTICIPATION AND DOUBLE COUNTING PERSPECTIVES FOR DISTRIBUTED RESOURCE MARKET PARTICIPATION

An EPRI FO2222 Phase 1 Collaborative Report

- Wholesale Market Operations & Design
- Distribution Reliability & Safety
- Transmission Operations & Planning
- Transmission, Distribution & Aggregator Coordination
- Information, Communication, Cyber Security
- Customer Technologies & Retail Programs

Bringing together key stakeholders to ensure the reliable and economic participation of distributed energy resources in wholesale electricity markets and establishing a research and development roadmap

January 2022

Abstract

Substantial distributed resource penetration alongside rapid growth and interest in wholesale market participation has compelled scrutiny over the possibility of dual participation, a situation in which one distributed resource can simultaneously participate in multiple programs or services, particularly across wholesale and retail domains. FERC Order 2222 directed ISO/RTOs to allow for dual participation, while also directing them to prevent double payment, where a resource is compensated more than once for providing the same service (e.g., retail bill savings and wholesale payments for the same kWh). Perspectives on dual program participation combinations that are acceptable can differ by stakeholder type and region and are also influenced by existing DER and DR programs in place. This report summarizes perspectives on dual participation and double counting by considering diverse perspectives across the electric power industry, including regional differences in market structures, metering methods, and existing DER/DR programs. Key perspectives are summarized by stakeholder type based on commonalities noted from compiling feedback through collaborative webcast exchange, individual and group interviews, as well as online polling conducted by EPRI during mid-2021. Distinct methods for metering distributed resources are described, along with associated pros, cons, issues, and potential resolutions. Different configurations of sub-metering are highlighted to explain how sub-metering contributes to double counting. The report concludes with recommendations for avoiding double counting and notes future work needed to advance retail programs towards better alignment with wholesale cost drivers.

Introduction

Purpose

FERC Order 2222 directed Independent System Operators and Regional Transmission Organizations (ISO/RTOs) to enable participation in energy, ancillary services, and capacity markets when technically capable of doing so. A key directive in the ruling was to allow for dual participation across wholesale markets and retail programs, which differed from FERC's stance in the proposed rulemaking. That is, the directive allowed for distributed resources participating in one or more retail programs to be eligible to participate in wholesale markets.

FERC also directed ISO/RTOs, working with distribution utilities and relevant electric retail regulatory authorities (RERRA), to provide restrictions on distributed resource participation in wholesale markets, when narrowly designed to avoid the possibility of being paid twice for the same service. The purpose is to avoid preferential treatment, including situations of double payment for providing the same service, measured in kW or kWh, when participating in a wholesale program and a retail program simultaneously. ISO/RTOs are to describe how they plan to do so within their compliance filings.

Review of comments submitted to FERC on this topic reveals diverse perspectives on dual program participation in the electric power industry. This report begins by clarifying terminology surrounding distributed resource technology types, programs, and implementation alternatives. Differences between electricity producing distributed energy resources (DER) and demand responsive loads are highlighted, along with how DER programs differ from demand response (DR) programs. The report then summarizes perspectives on dual program participation by stakeholder type, clarifying commonalities and differences in perspectives, and providing examples of where dual program participation is allowed, disallowed, and rationale why. Regional differences in perspectives are also high-

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This white paper was prepared by EPRI.

lighted, which are attributable to the particular market contexts and rules under which programs exist. Findings are summarized based on primary research conducted by EPRI during mid-2021 through collaborative exchange, one-on-one interviews, and group polling.

This report frames the issue of double counting for ready identification of situations where it may occur and recommends ways to avoid double counting. Where double counting occurs is clarified through delineation of distinct metering alternatives, followed by a discussion of pros, cons, and issues associated with each alternative, and how the issues may be resolved.

Terminology

Particular use of terminology is first summarized below, to clarify terms employed in the remainder of this report.

Distributed Resources

Distributed Energy Resource (DER) is a term that has compelled frequent clarification. DER is used broadly by FERC to refer to any resource located on the distribution system, any subsystem thereof or behind a customer meter. FERC further clarifies that the resources may include, but are not limited to, electric storage resources, intermittent or variable energy resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.

Demand response resource is referred to in FERC Order 745 as a resource capable of reducing consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.

Nevertheless, many ISO DR programs as well as utility DR programs also incentivize increasing consumption at targeted times, beyond just decreasing consumption. Moreover, much of the ensuing technical discussion in this report refers to only electricity producing DER, and not demand responsive loads. Therefore, DER is used henceforth as shorthand to refer to electricity producing types of distributed resources, and not demand responsive loads which are not capable of producing electricity.

Both DER and demand responsive loads can provide valuable services through adjustments in output and/or consumption coordinated with system or market needs. Examples of distributed resources are provided at the bottom of Figure 1. They can be grouped by technical capability and characteristics as follows: 1) intermittent renewables, 2) non-intermittent DG, 3) distributed storage, and 4) demand responsive loads.
Figure 2 differentiates these four distributed resource groupings by ability to produce power and/or consume power. The figure illustrates some resources as capable of producing electricity (for potential export to the grid).

Demand Response (DR) stems from adjustment in output of distributed resources (e.g., DG, ES, demand responsive loads, electric vehicle) coordinated to support system or market needs. The desired adjustment or DR is motivated through demand-side program provisions, market opportunities, or grid operating requirements. The desired adjustment can be actuated through a variety of mechanisms (e.g., manual actions, direct control, demand limiting control), and incented through a variety of program approaches (e.g., discounted rates, financial incentives, or penalties for deviating from firm commitments).

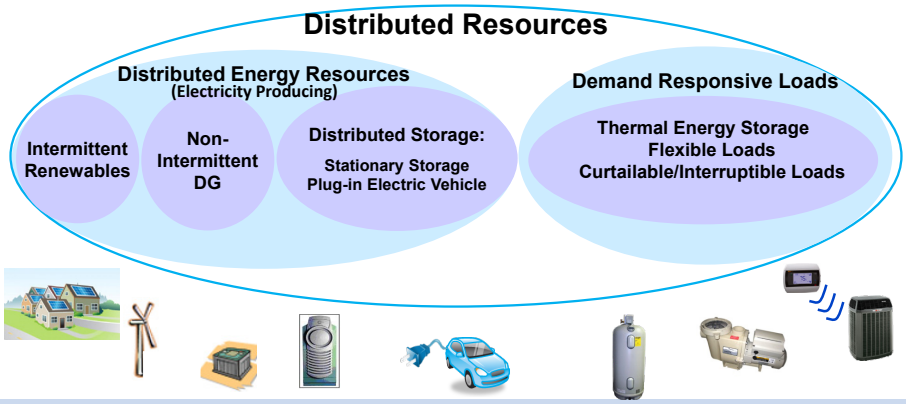

Figure 1. Distributed Resource Types include Electricity Producing DER and Demand Responsive Loads

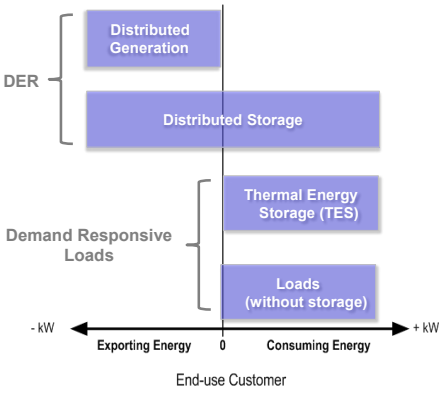

Figure 2. Distinguishing Distributed Resource Types

Dispatchable DR programs generally trigger a quantity response from distributed resources coordinated in operational timeframes (e.g., day-ahead or day-of when the response is needed). This is in contrast to programs without a provision for dispatchable DR (e.g., Time of Use, real time pricing, etc.). Nevertheless, price responsive programs may also include designs supportive of power system and/or market operational needs (e.g., provisions for controls or automation to actuate price-based response).

Behind-the-Meter (BTM) versus Front-of-Meter

A behind-the-meter DER asset can be capable of producing electricity. The electricity can be used on-site without injecting past through a customer meter, and/or exported to the grid by passing through a meter, as program provisions allow. In contrast, electricity produced by a front-of-meter DER asset must pass through an electric meter before reaching end-use customer load. Figure 3 illustrates the two described DER configurations.

DER Programs

DER and DR programs are increasingly being employed to support functions across the electricity value chain. Applications range from provision of resource capacity, energy, or ancillary services to congestion management, network expansion deferral and asset protection.

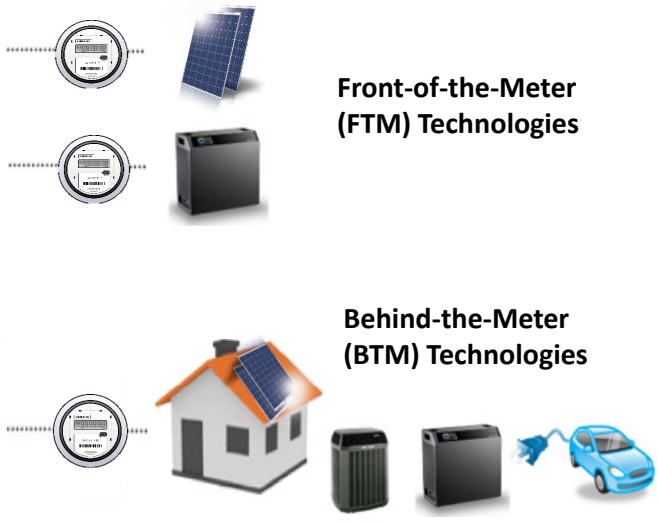

Figure 3. Front-of-the-Meter Technologies versus Behind-the-Meter Technologies

Programs under which DER participate vary in design, including whether there are provisions to accommodate DER interconnection, export, and/or dispatchability. Program rules determine what types of distributed resources can participate, and whether if capable, the DER is allowed to export power to the grid. For example, programs that accommodate customer-sited energy storage also determine whether will accommodate DER export or limit the size of the storage device to DR applications of net load reduction measured at the customer meter. Through size limitations and charging control algorithms for energy storage, program-imposed requirements can be enforced such as charging storage with only onsite renewable generation, using storage to displace power purchased from the grid, and limiting storage export to non-grid sources when charging.

For DER it becomes pertinent whether the program under which DER assets participate is designed to accommodate export and under what conditions. Therefore, DER programs differ from most DR programs in that the former determine whether DER can export, consume power from the grid, or both. These additional program provisions pertain to electricity producing DER, unlike programs only accommodating demand responsive loads.

For DER asset types capable of producing electricity, an interconnection agreement is generally required. The agreement dictates whether DER export is allowed or in the case of BTM DER, whether the DER is only configured to support facility loads. Although some wholesale and retail programs that are grouped under a market operator or load serving entity's "Demand Response Programs" enable electricity export to the grid, DR programs generally do not enable export from distributed resource assets behind the customer meter. In this way, DER export programs are distinguished from most DR programs designed to merely displace grid purchased power.

DER Technology Penetration

DER technologies such as solar photovoltaic (PV) and energy storage have exponentially grown since 2010. Figure 4 and Figure 5 illustrate the cumulative installations and projected installations of solar PV and energy storage in the U.S. over two decades. The charts also provide details illustrating exponential growth of distributed PV and storage from behind-the-meter DER installations (e.g., residential and non-residential BTM PV and storage).

By the end of 2020 the 3rd quarter, 95,378 MW of solar PV was installed across the U.S. Projected out to 2025, the cumulative installed capacity of solar PV is to reach 202,624 MW.

The cumulative capacity of energy storage systems reached 2,777 MW by quarter 3 in 2020, including both electrochemical (battery) and electromechanical (e.g., flywheel) technologies. This number is projected to grow to 101,517 MW by the end of 2030.

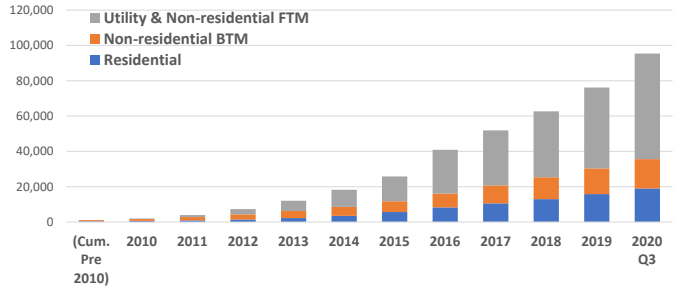

Figure 4. Cumulative U.S. Solar PV Installations.
Data Source: Wood Mackenzie (2020, Q3)

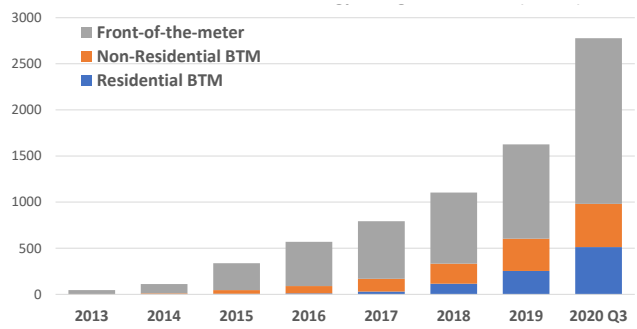

Figure 5. Cumulative U.S. Energy Storage Capacity.
Data Source: Wood Mackenzie (2020, Q3)

Figure 6 provides a regional perspective on electric vehicle (EV) registrations by state at the end of Year 2020.

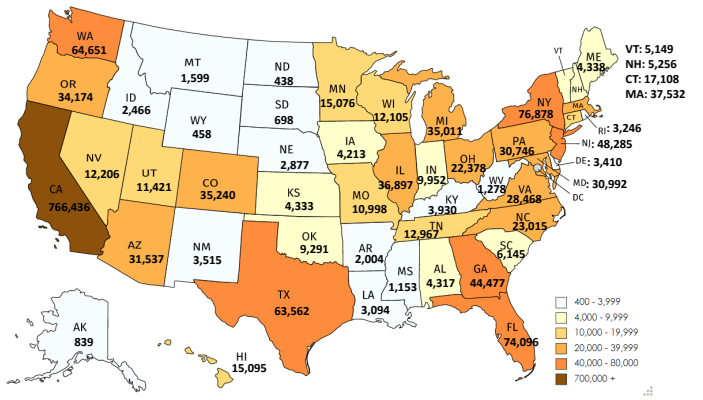

Figure 6. Regional Electric Vehicle Registrations.
Data Source: EPRI Electric Transportation Program, Dec 2020

Dual Program Participation Perspectives

Dual Program Participation

Exponential growth in DER penetration has occurred alongside rapid growth in program participation. The growth has compelled scrutiny over the possibility of dual program participation, a situation in which one resource can simultaneously participate in multiple programs, including both wholesale and retail.

Distributed resources have been applied to avoid costs and provide valuable services across the electricity value chain, through both wholesale and retail programs. Figure 7 illustrates types of opportunities for distributed resources to be employed in wholesale markets, electric delivery systems, and/or retail programs.

FERC Order 2222 directed Independent System Operators and Regional Transmission Organizations (ISO/RTOs) to identify rules restricting dual program participation. The purpose is to avoid a situation of double payment for a distributed resource's contribution when providing essentially the same service through both a wholesale and a retail program, under which it participates simultaneously. The Order also directed the ISOs to prevent double payment from multiple wholesale services, such as a distributed resources participating in both a DER and DR aggregation, or in two separate DER aggregations providing the same service.

Diverse perspectives on dual program participation is evident across the electric power industry, including in comments submitted to FERC on this topic This section summarizes dual program participation perspectives by stakeholder type, based on feedback received under Phase 1 of EPRI's FERC Order 2222 Collaborative. Feedback was compiled through collaborative webcast exchange, individual and group interviews, as well as polling conducted by EPRI during mid-2021. These perspectives do not represent official positions or specific perspectives by any individual companies but are based on aggregate views as interpreted by the project team.

Perspectives by Stakeholder Type

ISO/RTO

Based on discussions so far, ISO/RTOs are generally willing to accommodate dual program participation. Market rules may allow for DER to be aggregated by a DER aggregator (DERA) for participation in the wholesale markets while also participating in programs. Specific examples of dual program participation exist including dual participation in wholesale market services and non-wires services or participating in certain retail programs. ISO/RTOs are accommodating so long as all of the following conditions are met:

1. the same service is not doubly compensated,
2. the DERA meets wholesale market participation obligations and schedule when simultaneously providing retail service (through self-scheduling as example), and
3. the distribution utility consents to the DERA participation

The last condition can be demonstrably met to an ISO/RTO during the registration process with the aggregator, where the aggregator must provide an attestation that the aggregation is compliant with distribution utility tariffs and any rules and regulations of the RERRA.

Regarding the meaning of dual "participation", ISO/RTOs were asked to clarify whether this refers to dual registration, dual bid/offers, and/or dual dispatch and service provision under the context of participation in both a wholesale and retail program simultaneously. As a group ISO/RTOs clarified dual participation refers to:

a. simultaneous registration in both wholesale and retail programs is possible,

b. overlapping timeframe for a resource to be reserved or committed under both retail and wholesale programs is possible, and

c. dispatch for up to one service is possible at any given time

Differences exist across ISO/RTO market contexts, rules, and industry structures. A few nuances were identified that merit further investigation pertaining to aggregate DER participation. They include:

- Heterogeneous DER aggregations (that include both DR measured against a baseline and direct-measured DER) are challenging for ISO/RTOs to address in terms of measurement and settlement, particularly in light of DR compensations rules under FERC Order 745. Such rules require DR resources to be paid the prevailing locational marginal price for energy whenever economic, which in turn results in lower energy bills from lowered consumption. Such rules must be reconciled with the FERC Order 2222 directive to ISO/RTOs to avoid double compensation for the same service.
- Some existing ISO/RTOs programs allow for BTM DER export beyond the customer meter (e.g., DER export allowed by ISO-NE and CAISO), while others do not (e.g., PJM).
- Must-offer rules apply to both DR and DER in some regions (e.g., CAISO, ISO-NE), but do not fully apply to DR nor BTM DER in other regions (e.g., PJM). In ISO-NE and NYISO the must-offer rule applies to resources including DR/DER with Capacity Supply Obligations. In CAISO it applies to resources with Resource Adequacy obligations. Resources under such obligations must bid into subsequent markets for energy and/or ancillary services. However, in PJM there is also a must offer rule for bulk generation resources to bid capacity in subsequent years after initial capacity award, which does not apply to DR nor BTM DER.
- Metering requirements vary along with the extent monitored data from DR/DER technology is acceptable for billing/settlement, or only used for operational awareness.

Distribution Utility

From a distribution system planning and operations perspective, utilities are generally willing to allow DER to provide multiple services so long as the services are technically compatible. Furthermore, the metering/telemetry for data sharing must be made available and allow industry stakeholders to adjust retail billing should that be necessary to avoid dual compensation.

When distributed resource dispatch is needed to provide capacity relief to the distribution system, distribution utilities generally believe that they have first right to call on those resources, if the resources

registered first with the distribution utility (i.e., before registering for a wholesale market program).

Regarding the meaning of dual "participation", distribution utilities were asked whether refers to dual registration, dual bid/offers, and/or dual dispatch in both a wholesale and retail program simultaneously. As a group, respondents unanimously agreed that dual participation refers to allowing simultaneous registration in both wholesale and retail programs. However, respondents differed in opinion as to whether would allow for resources to be reserved or committed for an overlapping timeframe under both a retail and wholesale program. They also differed as to whether dispatch for more than one service would be possible at any given time. Detailed examples are noted next.

For the few days or hours per year when the distribution system operator (DSO) needs to dispatch resources to alleviate network constraints, dual participation in a program providing capacity on reserve to an ISO would not be allowed. It is not technically feasible to be providing a distribution service to alleviate network constraints while on standby at the same time to provide reserves.

However, a dispatchable resource can simultaneously provide capacity to the distribution system AND be compensated for selling energy to the wholesale market. Some might call this dual compensation, while others would classify these as two separate services. From the technical side, the two programs appear compatible, but from the compensation side there could be differences in opinion.

If a non-dispatchable DER such as PV is participating in a retail program for energy such as Net Energy Metering (NEM), then it cannot simultaneously participate in a wholesale program for energy without concerns of double payment. Under NEM exported energy during the billing period is credited based on the NEM rate structure. If PV on NEM is also participating in a wholesale program during certain times of the month then there is some reconciliation needed to determine when the injection is to be credited based on the retail rate versus the wholesale compensation scheme. That is, if a customer is participating in both NEM and a wholesale market then coordination is needed to determine when the PV export is subject to NEM and when it is credited at wholesale.

More sophisticated interval meter reading capability beyond that of a net energy meter is required to enable the metering data to be used for settling the wholesale service. This data would need to be provided to the distribution utility to reconcile the retail billing and avoid paying the DER owner for both retail and wholesale energy during the same time interval.

Load Serving Entity

Load serving entities (LSEs) meet customer electric service needs with retail programs including tariffs. They shoulder the obligation to serve utilizing existing load aggregation systems, while addressing regulatory mandates.

LSEs keenly recognize state-level authority over avoiding double compensation when establishing program restrictions. Given their traditional load aggregation role as well as possible ongoing role as distributed resource aggregators, LSEs contribute important perspectives to the dialogue. In stakeholder processes towards establishing workable market rules for accommodating DER compatibility with DR programs already in existence, LSEs are uniquely positioned to provide feedback while considering the impact to existing load aggregation processes and systems.

Regarding the meaning of dual "participation", load serving entities generally shared the opinion of distribution utilities. They unanimously agreed that dual participation refers to allowing simultaneous registration in both wholesale and retail programs. There were differences in opinion as to whether would allow for resources to be reserved or committed for an overlapping timeframe under both a retail and wholesale program. They also differed as to whether dispatch for more than one service would be possible at any given time. Conditions under which dual program combinations are allowed, disallowed and rationale why are discussed next.

Allowed: LSEs generally support dual participation of distributed resources in retail programs for capacity aggregated into wholesale programs for capacity and/or while participating in another market service. There are examples of LSEs in restructured market regions offering retail capacity programs for DR/DER that is then aggregated for participation in a regional wholesale capacity auction market, wherein the LSE serves as the DER/DR aggregator. The same DER/DR resource may also be bid into subsequently cleared markets for energy and ancillary services (e.g., operating reserve or frequency regulation). However, in such cases the market clearing by the respective ISO/RTO operating the market system determines the dispatch outcome, so that the same resource is only dispatched and compensated once for real-time energy.

In cases where the LSE has a retail program for distributed resource participation that is independent of the ISO/RTO dispatch, the LSE is generally supportive of dual program participation for capacity, so long as the LSE has the first right to dispatch assets registered in its retail program.

Not allowed: In multiple jurisdictions, limitations on dual program participation are cited, especially involving Net Energy Metering customers. These customers in many instances are restricted from participating in wholesale markets with behind-the-meter DER. Examples vary and stem from concerns about meeting rules of technology adoption programs such as renewable energy credits for PV installations or federal tax incentives for "clean energy" received to defray battery installation capital costs.

To comply with incentive rules, DER programs may restrict charging BTM batteries to customer-owned renewable-generated electricity only. This can be accomplished with algorithms of battery control that restrict charging to periods of local solar production or another scheme allowing only renewable energy charging but restricting grid-supplied electricity for charging.

Another reason for dual program limitations for NEM customers involves renewable energy credits that may restrict the customer's BTM battery to be charged only by the particular renewable source (e.g., solar rooftop) receiving credit.

These are just several examples of BTM battery incentives resulting in limitations on wholesale market participation for NEM customers. However, restrictions on market participation with BTM DER or DR assets of NEM customers are not universal across LSEs. Moreover, additional metering requirements may be in place for customers with PV on NEM to also participate in a wholesale DR or DER programs with additional BTM assets.

Business Impact from DER: For LSEs a distributed resource dispatched behind the customer meter also impacts the revenue collected by the load aggregator in the provision of electric service. DR generally reduces electricity consumption at a targeted period of time and/or shifts the load across a longer period of time. In the former case of load reduction without shifting (energy neutral case), a concern centers on revenue loss. Moreover, lost revenue can translate to ratepayers with DER/DR assets not paying their "fair share" of allocated costs. This is a particular concern for distribution services which are generally recovered on a volumetric basis of total measured energy over the entire billing interval, especially among mass market customers. Concerning customers with DER like energy storage or PV that are billed via net energy metering, the potential loss in revenue recovery can be quite substantial and not sustainable.

Settlement Cost Allocation: For LSEs in wholesale markets, settlement rules are of concern to the bottom line of load aggregation businesses. Proposals to isolate the costs for DER dispatch to affected networks may lead to a concentrated revenue impact on LSEs with DER interconnected to their respective networks. Regions that socialize costs for DR dispatch across more stakeholders, in effect spread the cost burden. To the extent wholesale settlement cost allocation rules align allocated costs carefully to beneficiaries and attribute risks to their sources, a disproportionate allocation upon LSEs may be avoided. Careful thought includes considering impacts to businesses that shoulder the responsibility as default electric service provider to retail customers.

Some regional differences are identified next that inform workable solutions for accommodating dual participation.

- **interval metering capability**: Instrumentation could occur at the whole-premises level or sub-metered level. The implications of existing metering capability factor into the degree of rework needed to accommodate DER participation in wholesale markets.
- **back-office systems**: LSE concerns include practicability and costs of requisite metering and back-office systems upgrades needed to accommodate dual program participation. Updates to processes and systems integration may also be needed to accommodate DER billing and market settlement.
- **market rules for DER export**: Regional market rules differ by whether DER export is allowed and accommodated under existing DR program constructs or only allowed under newer DER programs.
- **customer controlled DER**: Some LSEs accommodate DER dedicated to customer purposes with special programs such as rates for backup power from the grid. This impacts wholesale settlements and has cost allocation implications. Customer-driven uses for DER (e.g., demand charge management, microgrid application wherein grid is used for backup power) further complicate developments needed in rate restructuring and program design to accommodate adequate utility cost recovery through market settlements and customer billing.

Third-Party Aggregator

Third-party aggregators of distributed resources regard economic viability as paramount. They are proponents of program and market advancements to accommodate DER capabilities beyond DR (e.g., DER export), while leveraging existing technologies. To boost economic viability, third-party aggregators favor dual program participation for maximum return.

Third-party aggregators stress the economic importance of allowing distributed resources to participate in multiple services, and welcome an environment wherein different market participants would be enabled to provide different services to an ISO/RTO with the same resource. They recommend any restrictions on dual program participation be narrowly tailored, and generally view ISO/RTOs well-positioned to place checks to prevent double counting, so long as the utility is agreeable.

An ideal development they would welcome is when all ISO/RTOs accommodate DER export, preferably by leveraging existing monitoring technologies (e.g., DER inverters, data processing gateways) capable of DER-level metering and/or telemetry.

Generally, third-party aggregators do not want to be precluded from wholesale program opportunities, that would otherwise only be open to LSEs (e.g., PJM Price Responsive Demand option for demand-side participation in wholesale capacity and energy markets). In situations where an LSE is already aggregating a distributed resource in an ISO/RTO capacity market, third-party aggregators see a potential opportunity to represent the same resource in a subsequent market (e.g., for energy or ancillary services), if the market operator would allow.

Allowed: Many examples exist of third-party aggregators contracting in retail programs for capacity while also participating in wholesale ancillary service markets and providing energy with the same contracted resource. Seeking to maximize opportunities for value stacking, they recommend narrowly tailoring restrictions on dual participation.

Disallowed: Third-party aggregators cite examples of many retail customers on NEM tariffs with plans for BTM energy storage participation in wholesale markets, where allowed. But they also acknowledge restrictions are in place in multiple jurisdictions. Drivers behind restrictions resemble those previously discussed in this report, such as receipt of renewable energy credits or tax incentives for clean energy technology adoption.

Nuances: Some regional differences in approach for dual program participation that merit further investigation are identified below.

- **Settlement of DER performance**: Third party aggregators generally recognize the need for DER performance determination methods to advance beyond use of DR baselines, particularly for cases of DER capable of producing electricity and/or exporting power.
- **Monitoring and metering requirements**: Not only do program participation and settlement rules vary across retail and wholesale programs, but also minimum metering requirements and acceptability of utilizing DER-level monitoring to provide requisite sub-metering for billing and settlements.

Consumer Advocacy

The consumer perspective may be bifurcated into two categories: (1) DER technology enthusiasts, both current- and prospective- adopters; and (2) non-adopters of DER technology, including limited income consumers and their advocates.

The former category has a financial interest in expanded economic value streams for BTM DER. The ability to simultaneously participate in both wholesale and retail markets (both capacity/demand and energy) allows current and prospective DER adopters to better capitalize their equipment and enhance their return on investment.

The latter category of non-adopters has a different perspective. Whether their reason for not adopting DER technology is a financial limitation (e.g., low income, limited access to financing due to low credit, etc.) or something else, customers who are unable to participate in such wholesale and retail markets are likely to bear a higher share of the costs to maintain grid infrastructure. This is because DER adopters who participate in multiple markets reduce their revenue contribution to utilities, for which a portion goes to recovering costs for built infrastructure. Over time, as the share of DER adopters participating in such markets grows, the foregone revenue from these participants may lead to rate increases that would most affect DER non-adopters, since those consumers are not equipped to offset any rate increases with energy production or shifting through energy storage to take advantage of time-of-use rate structures.

Consumer advocates, particularly low-income advocates, argue that such a policy could potentially exacerbate economic inequity, disproportionately impacting disadvantaged consumers.

Technology proponents would argue that the answer is to expand consumer access to DER technology and market participation through policies and programs that reduce first cost barriers, such as on-bill financing, PACE, and similar mechanisms. Not only would this allow more consumers to reap the near-term economic benefits of market participation, but the long run effect of peak demand reduction and improved load factor caused by expanded consumer use of DERs would avoid future investments in grid infrastructure that therefore help avoid corresponding rate increases.

One of the key issues in market participation is the basis for settlement. A net-energy metering (NEM) approach essentially credits energy production at the same prevailing retail rate as energy consumption. This approach is generally favored by DER technology vendors and consumer enthusiasts. However, there are alternative settlement mechanisms that ascribe customized value to DER based upon location, capacity value, energy value, environmental value, and relief provided to the system. This can either be accomplished by separately metering the DER or applying an analytical approach to estimate DER production profiles. The latter approach has been adopted in New York state through its Value of Distributed Energy Resources mechanism, known more simply as the Value Stack. In practice, this has led to valuations that on average, compensate DER customers at an average rate less than the retail rate.

Future Work

Diverse perspectives on dual program participation are evident across the electric power industry. Perspectives are further influenced by the market context under which programs exist. Unique perspectives have been identified across market contexts and must be reconciled amidst the backdrop of existing DR programs and participation rules, including compensation rules for DR dictated under FERC Order 745. These are subjects proposed for future investigation for better clarity on areas of common ground.

Metering Alternatives for Accommodating Dual Participation

Metering Alternatives

Distinct implementation alternatives for metering DER are employed in the electric power industry. Figure 8 illustrates a predominant set of metering alternatives classified in a mutually exclusive way. This section discusses the pros, cons, issues, and resolutions associated with each alternative. Where double counting arises as an issue is highlighted, as the basis for how to avoid.

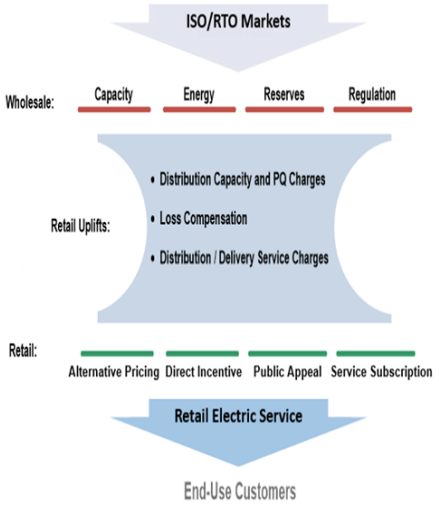

Figure 7. Opportunities Across the Electricity Value Chain

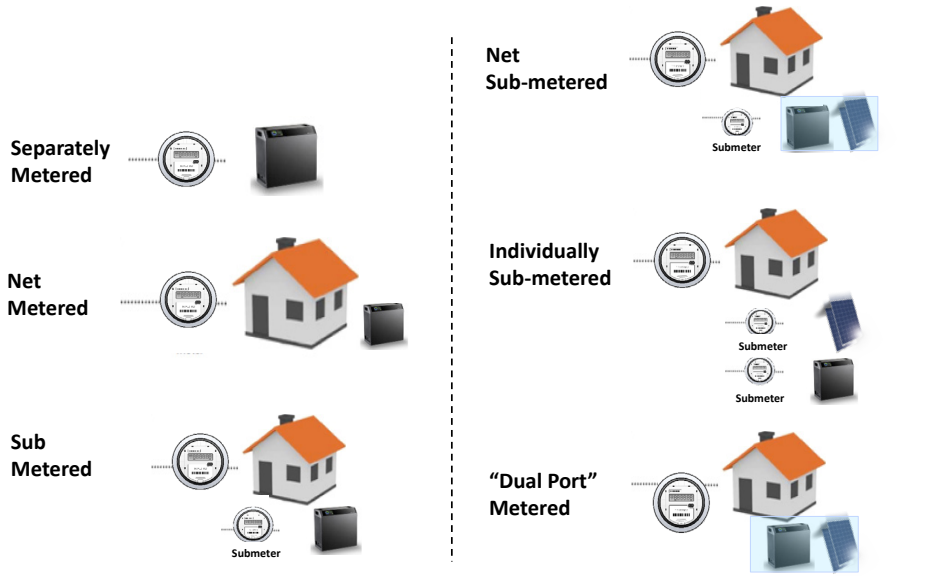

Figure 8. Alternatives for Metering DER

Separately Metered DER

Pros

When DER is separately metered from the existing customer meter, there is generally no double counting issue. Rather, separately metered DER is straight-forward for settlement and billing and so may be preferred where metering costs can be justified.

For large DER installations (e.g., 50kW DER size) relative to the connected load, it may be advantageous to connect the DER output to the point of interconnection. This metering alternative may be considered simpler for a utility to deal with by having two separate meters on the side of a building. This reduces the risk of tampering compared to sub-metering alternatives that could otherwise restrict utility access to the submeter. Separately metering DER also is compatible with providing visibility to voltage and putting protection in place for larger customers.

Cons

When the DER's output has to be brought all the way to point of interconnection, metering costs for interconnection may be more expensive compared to alternatives like sub-metering. Besides costs for metering and associated electrical work for interconnection, there may also be additional costs for market participation, such as contracting with Scheduler (e.g., Scheduling Coordinator or Qualified Scheduling Entity) for market participation of a separately metered DER.

Issues

Customer interconnection costs could be very high for low load or low load factor applications, such that costs may far outweigh benefits of market participation.

Resolution

Possible resolutions to the cost justification issue include:

- Increase the size of DER participation so that the potential upside from market participation justifies expected costs and associated risks.
- Review existing interconnection requirements to streamline and lower interconnection costs.

Improvements may be identified that could ensure consistency and cost equity towards improved affordability of separately metering DER.

Net Metered DER

Pros

When DER is net metered with the customer load utilizing a net energy meter, there is generally no double counting issue introduced by the net metering method. A primary advantage of net metering is the convenience of leveraging an existing customer meter for billing and settlement of DER program participation. This is generally more cost advantageous than other metering alternatives, and also simplifies settlement and billing.

Net metering is a common alternative utilized by demand response programs to determine demand response performance. The net meter measures net consumption at the customer meter during demand response events. By comparing this against an established customer baseline indicative of normal customer usage patterns, performance is determined for DR program settlement purposes. Similarly, net metered DER is settled based on net electricity usage or production measured at the customer meter.

Cons

Disadvantages of net metering DER stem from its simplicity and measurement limitations. Key DER parameters, such as quantity and periods of DER production and/or consumption (e.g., battery charging) are not captured by a net meter.

Moreover, net metering makes it difficult to reconcile the source of electricity for charging a BTM battery, which is particularly relevant under situations of Net Energy Metering with PV. That is, was the battery charged by net-energy-metered PV or grid provided power? This may pose complications for an LSE claiming renewable credits from NEM installations, as well as customers or DER aggregators receiving federal investment tax credits for clean energy.

As a result, clean energy programs that rely on net metering DER may pose restrictions where BTM batteries are involved. For example, BTM batteries may be restricted to charge only during periods of local solar production in installations with net metered PV. Local algorithms controlling battery charging can enforce such restrictions. Therefore, net metering DER can pose limitations due to simplicity of measurement, for which controls may be utilized to help overcome.

Issues

A major issue for utilities is when customer sited DER causes volumetric energy sales to decrease to the point that retail sales revenue fall short of supporting the costs of providing electric service. That is, DER may cause a situation of underutilized utility assets, which in turn may lead to a situation of inequitable cost recovery across customer segments.

Under retail rates that rely on volumetric energy as the primary billing determinant, a customer with net metered DER would typically displace grid-purchased power with DER-produced power, so that the customer's net metered energy consumption is reduced substantially.

However, the fixed charge component on the customer's retail bill is often established historically based on an assumption of average energy usage being much higher for the applicable customer class. The end result can be interpreted as retail customers without DER subsidizing retail customers with DER. This leads to an unsustainable situation as more customers adopt DER under traditional Net Energy Metering rate structures, if customers without DER (including low-income customers) are left to subsidize those with DER.

Resolution

The primary resolution to the described issue of cross subsidization lies with retail rate restructuring, particularly for mass market customers (i.e., residential and small commercial customers). Standby rates (wherein the utility provides grid service as backup to the customer with DER) are typically insufficient to overcome the described situation of revenue shortfall, let alone default retail rates. Unbundling rates may help but unbundling is typically based on averages.

Some ways to address the effect of net metered DER being subsidized by customers without DER, include:

1. Consider retail rate restructuring for better transparency of utility cost drivers to achieve cost reflectivity through restructured rate or service plans, especially for mass market customers. In particular, consider restricting network charges based on non-coincidental peak, wherever interval meter recording is available.
2. For DER that can be modeled with some consistency (e.g., PV), create separate rate structures wherein risks and benefits are shared by participants. This will require load research with representative samples for different DER customer segments.
3. Consider including customer demand (e.g., measured in kW) as a billing determinant in retail rates, especially for mass market customers. Consequently, avoid time-of-use rates lacking a network charge based on peak demand as a billing determinant. Such rates lacking measured demand increase likeliness of reducing cost recovery and producing cross subsidies, potentially between high-capacity factor DER to low-capacity factor DER and between DER non-participants and DER participants.

Many examples of residential customer rate structures with measured demand as a billing determinant exist around the world. Though most electric utilities in the United States do not yet offer such rates, the challenges of growing DER penetration from customer adoption is compelling industry re-thinking towards more cost-reflective rate structures that customers can handle, and that can impact wholesale cost drivers for an overall win-win outcome for utilities and customers.

Sub-Metered DER

Pros

When DER is sub-metered behind the existing customer meter, double counting becomes an issue. However, this metering alternative is frequently implemented with the following advantages.

1. Sub-metering gives visibility to DER consumption and export measured at the submeter, so is straight-forward for settlement with the ISO based on the DER asset's contribution. For example, sub-metering is needed to measure ancillary service provision not sufficiently captured at the whole premises level for settlement purposes (e.g., for frequency regulation).
2. For customer-sited DER, sub-metering is generally less expensive than separately metering DER. Cost advantages include:
   - Avoids added account management for utility compared to separately metering
   - May involve less electric work to connect the DER versus bringing the conductor to the utility point of interconnection
   - Submeter may be built into other devices required for installation like a protective relay or inverter
   - Submeter may be mounted indoors in less weather restrictive enclosures, eliminating need for additional enclosure needed to protect from elements and provide a safety barrier

Cons

Despite its advantages, sub-metering DER also poses multiple challenges, such as:

1. Potential for double counting of identical services
2. Potential for meter tampering, due to third-party ownership and access to the submeter
3. Question of submeter accuracy
4. Use for incentive payments and settlement is problematic
5. Settlement may require network charge
6. Impact evaluation is uncertain, and may not reflect what would be produced in the absence of the connection nor reflect secondary effects (e.g., temperature-related, or behavior-related)
7. Sub-metering does not support cutting off the load with one meter while leaving the DER connected to the grid. (Having the ability to only shed load would be valued by the utility in a load constrained event.)
8. Risk of impact measurement shortfalls fall on the distribution utility or load serving entity

Issue of Double Counting DER Contribution

A primary issue stemming from sub-metering DER is the potential for double counting. This potential is illustrated in Figure 9. The blue arrows indicate types of measurements associated with the three primary metering alternatives discussed thus far, shown on the left side of the figure. Different variations of metering involving multiple DER are shown to the right of the figure.

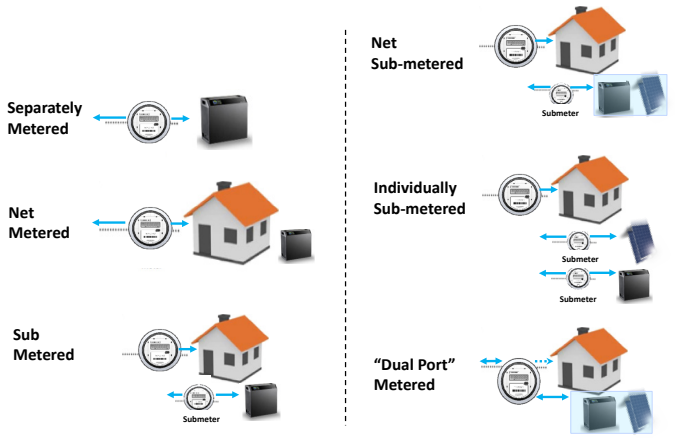

Figure 9. Measurements Associated with Metering Alternatives for DER

The blue arrows indicate the types of measurements supported under each metering alternative. For example, separately metered DER supports measurements of DER export and consumption to/from the grid, whereas net metered DER measures net production and consumption at the customer meter.

Unlike net metering, sub-metered DER directly measures an individual BTM DER asset's contribution, in terms of production as well as consumption. Moreover, the customer facility-level meter is inclusive of the BTM DER's contribution, potentially leading to double counting the DER's contribution.

Similarly, each variation of sub-metering shown in Figure 9, includes the contribution of several sub-metered DER assets in the overall measurement at the facility-level meter. The two blue arrows pointing to the right in each of the sub-metered cases, is indicative of the overlap between measured facility-level consumption and measured DER consumption. The overlap is apparent whether the DER sub-metered is energy storage, the net of solar and storage, or individually sub-metered solar and storage. Each of these three illustrated variations of sub-metering show two solid blue arrows to the right of the customer meter, which is indicative of the potential for double counting the contribution of BTM DER.

In contrast, dual port metering (the last case illustrated in Figure 9) measures facility-level net import (i.e., net electricity delivered to facility from the grid) as well as DER net consumption, so that there is no overlap in measured DER contribution. From these measurements, customer load can be calculated net of the contribution of DER.

Issue of Costs for Remedies

The avoid double counting DER contribution under any variation of sub-metering, distribution utilities would be required to associate sub-metered DER with premise level metered account. For example, this association can be done by linking sub-metered data through a back-office application that has data from both primary meters and submeters. This requires added capability and system enhancements, and associated costs to be borne by the distribution utility.

Sub-metering may also lead to concerns over who owns the sub-meter and is responsible for its accuracy. This however could be mitigated if the two meters were a system owned and managed by the distribution company. Moreover, cost of sub-metering versus accuracy remains an issue for measurement to support ancillary services.

Resolution

One way to prevent double counting the contribution of sub-metered DER is to reconstitute (or reinstate) the DER customer's metered load. This can be done by backing out the contribution of BTM DER from facility-level meter measurements in order to remove the overlap previously described.

This reconstitution step is relevant for fixed cost allocations under cost-of-service investigations to inform retail rates. In order to avoid network subsidization of DER, a rate design can be employed to unbundle the network demand charge. The design may help shift DER consumption to lower cost periods (e.g., battery storage shifted from afternoon peak demand to charge at night). Reconstitution for cost of service may be aided by ample impact evaluation.

Another way to avoid double counting DER contribution is to deploy advance metering technology such as dual port metering or other metering technology capable of providing measurements or calculated values for: i) grid-delivered power, ii) BTM DER net production, and iii) customer load.

Conclusions and Recommendations

Reconstitute to Avoid Double Counting Sub-Metered DER

The previous section described distinct metering alternatives for DER. By considering the pros, cons, issues, and resolutions associated with separately metering, net metering, and sub-metering DER, respectively, the reader can prepare to address situations requiring steps to avoid double counting.

In particular, sub-metering DER counts the contribution of DER twice, once through the facility-level meter and again through the submeter. Sub-metering may involve just one DER asset or multiple BTM DER assets, which may be netted together or individually sub-metered. Regardless of the particular sub-metering configuration, reconstituting the load is needed to back out the contribution of DER from the facility-level meter.

Adopt Dual Port or Multi-Port Metering

An alternative to more prevalent metering practices of sub-metering, net metering, or separately metering DER, is to adopt advanced metering capabilities that by nature avoid double counting the contribution of DER. In particular, dual port metering (for the case of one DER) or multi-port metering (for the case of multiple DER) is capable of providing measurements that discern grid-supplied versus DER-supplied power for a calculable quantity of customer facility load (without DER consumption included), thereby avoiding double counting the contribution of BTM DER. Utilities considering advanced meter rollouts in the face of accommodating higher penetrations of DER may find opportune timing to deploy dual port metering capability.

Align Retail Billing Structures with Cost Drivers

DER and DR assets can be engaged in a broad range of programs and employed for a variety of different objectives in support of stakeholders performing distinct power system functions across the electricity value chain. Alternatively, distributed resources can be devoted primarily to meeting customer specific service needs (e.g., premium power applications for enhanced electric service reliability, customer demand charge management, or microgrid applications wherein the grid provides backup power.)

In such applications that employ DER to prioritize customer needs, the need for retail bill restructuring is further pronounced. For example, network and other fixed costs bundled under fixed retail charges may be inadequate to compensate for the loss of volumetric energy sales due to DER, under arcane rate structures that assume historically higher average energy sales. Examples were discussed in Section 3 under the context of Net Energy Metering DER.

Consider Unbundled Demand Charges for DER Customers

Retail rate restructuring is key for sustainably accommodating DER participation in retail and wholesale markets. In particular, retail rates that are cost reflective would also consider measured demand (kW) as a billing determinant on mass market customer bills. This is a gradual process requiring educating mass market customers on how power demand (measured in kW) differs from energy (measured in kWh), and how demand is a major contributor to underlying system costs to serve customer demand reliably. Moreover, customers need to understand how restructuring would benefit them in terms of improving affordability and reliability of electric service, through structures that more accurately reflect underlying system costs.

Doing so will help the electric power industry transition retail rate structures that currently recognize energy as the primary billing determinant that customers can impact, to structures that also recognize the importance of instantaneous demand. This is another

important step to accommodating dual program participation of DER and avoiding mis-aligned outcomes.

Enable Impactful Customers by Advancing Retail Programs

Power demand is a major cost driver in the provision of electric service reliability, which mass market customers are generally not incented to impact outside of enrollment in DR programs. However, customers can contribute to avoided costs through adjusting power demand. By advancing retail programs aligned with actual cost drivers and including provisions to help customers automate their preferences for demand (e.g., demand limiting appliances and breakers for lower priority uses), the power industry can collectively advance programs designed to enable impactful customers who are economically incented to adjust load and help capture avoided costs. Collaborative advancement of retail programs is key to achieve and sustain definitive steps of progress.

Future Work

Clarify Stakeholder Perspectives while Respecting Regional Differences

Regional differences are readily apparent, from the extent of electric power industry restructuring to the degree wholesale cost components are treated as pass-through costs on end-use customer bills. Cost allocation methods also vary across wholesale markets as do cost recovery methods of utilities. Depending on the settlement and cost allocation rules for DER/DR, different stakeholder types in the electric power industry are incented accordingly to aggregate DER/DR.

Respecting regional differences is one step towards clarifying stakeholder perspectives, including differences within a stakeholder type. For example, Section 2 discussed differences in distribution utility perspectives with respect to what dual "participation" means. Moreover, some jurisdictions accept dual participation of Net Metering customers in wholesale markets, while others restrict such possibility.

Distinguish Market Contexts

Where divergent perspectives are identified may be further explained by the particular market contexts under which programs exist. Market contexts, cost recovery and unbundling methods collectively drive business implications for DER.

Therefore, recommended future work includes framing the unique market contexts providing the background and environment for DER participation. A side-to-side comparison of market requirements can reveal similarities and reconcile differences in perspectives admis the backdrop of existing DR programs and participation rules, including compensation rules for DR dictated under FERC Order 745.

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