Quantifying and Transferring the Value of Grid Impacts and Environmental Attributes of Building Decarbonization Programs

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ABSTRACT

The market values associated with the environmental attributes and grid impacts of building decarbonization programs are anticipated to soar in the coming decade. These trends are driven by diminishing capacity reserve margins predicted by regional electric reliability organizations, as well as the rise of energy transition investing and clean energy goals among large corporations, including many electric utilities.

At the same time, the rollout of the Inflation Reduction Act (IRA) Home Energy Rebate Programs and the transition toward compliance with Federal Energy Regulatory Commission (FERC) Order 2222 will add new stakeholders responsible for managing distributed energy resource (DER) programs, to include more state energy offices as well as private organizations. As these non-utility (state and private) program administrators proliferate, transparent mechanisms will be required to allow these actors – along with legacy utility program administrators – to fully and fairly account for the grid and environmental benefits of the projects they incentivize.

This paper explores both proven and emergent mechanisms for quantifying and transferring the value of grid impacts and environmental attributes of building decarbonization projects from the various parties generating these benefits to those who value them in the market, with the aim of informing strategies that will be crucial for achieving rapid, reliable, and affordable building and grid decarbonization.

Introduction

Energy utilities' distributed energy resource (DER) programs (i.e., energy efficiency (EE), demand response (DR), building electrification, and distributed renewables) constitute a large-scale machine converting massive capital investments into building and grid decarbonization projects across the United States. With investments that total over seven billion dollars annually in building EE and DR alone (Figure 1), these demand-side management (DSM) programs – here, discussed as a subset of building decarbonization programs – have been a dependable mechanism for large scale market adoption on the customer side of the meter (Metzger et al. 2022). While programmatic investments in electrification and other DER programs are not systematically reported in similar formats, one could expect that the aggregated value of building decarbonization program investments would significantly exceed those shown in Figure 1.

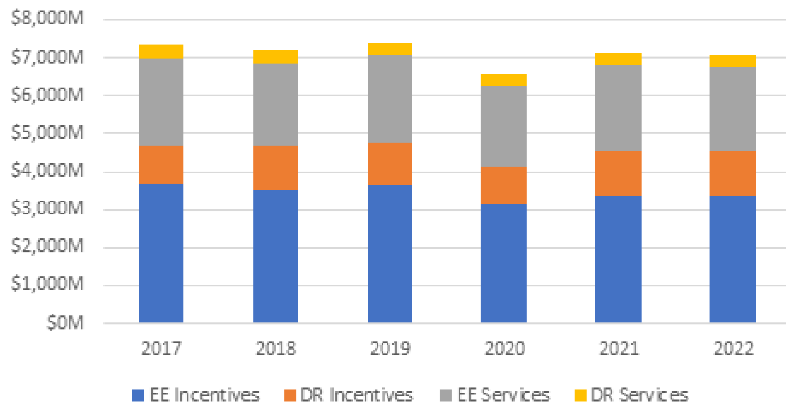

Figure 1: Electric Utility Demand-Side Management (DSM) Investment. *Source*: EIA 2024.

Despite this considerable investment coming from the energy utility sector, present levels of investment in building decarbonization via DER programs are insufficient to bring the real estate sector in line with the United States' goal of a net-zero emissions economy by 2050 (RMI 2024). Accordingly, scaling up this decarbonization machine to produce desired societal and system impacts in the required timeframes will necessitate significant additional investment from energy utilities, as well as additional public and private investors.

Fortunately, many of these investments are already proven to be cost-effective under conventional valuation paradigms. Consider investments made by energy utilities. Relevant markets and regulatory constructs in the U.S. recognize a variety of benefits from DER programs that may be accounted for when assessing the cost-effectiveness of these investments. These benefits include: avoided capacity costs; avoided energy costs; avoided transmission and distribution costs; environmental benefits, often expressed in terms of carbon dioxide equivalent avoided greenhouse gas emissions (CO2e); water efficiency impacts; public health benefits; and more. The specific methodologies for assessing each of these benefits vary by state regulatory body, by type of utility (i.e., quasi-federal agencies, municipal, cooperative, and investor-owned utilities), and sometimes by each individual utility. Figure 2 below shows the variation of the avoided cost benefits from the same kWh and kW reduction according to practices applied by investor-owned electric utilities in a sample of states.

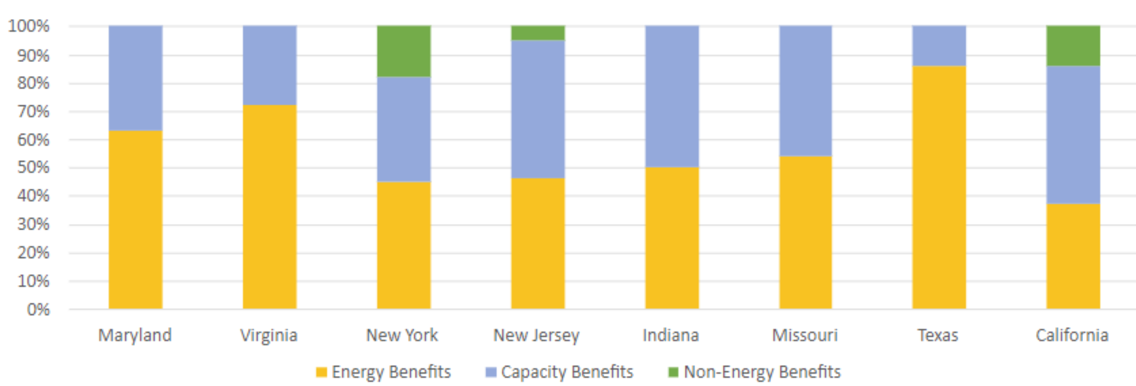

Figure 2: Variation in Avoided Cost Components of DSM Programs Applied Across U.S. Investor-Owned Electric Utilities in a Sample of States. *Source*: Emerson 2023.

The wide variation among the states demonstrates the inconsistency of methodologies applied across the country (as well as the avoided cost components themselves) and betrays a lack of significant value presently attributed to the environmental attributes of the projects (i.e., non-energy benefits). The expansion and standardization of the building decarbonization program benefits recognized by utility regulators has been one of the most profoundly important policy initiatives of our industry in the past decade and will likely continue to prompt reform in the years ahead (LBNL 2020). In this paper, we look beyond traditional cost-effectiveness assessments to consider the ways in which two of these benefits – capacity and environmental attributes – are actually *realized* (or monetized) by the program investors upon implementation; if some version of the reforms proposed here is adopted, we would expect impacts to translate into more consistent and favorable cost-effectiveness assessment methodologies as well.

We focus on capacity not only because it is often the most significant factor in determining building decarbonization program cost-effectiveness, but also because the North American Electric Reliability Corporation (NERC) presently classifies roughly two-thirds of the U.S. as being at "high" or "elevated" reliability risk, due in part[1] to capacity deficits that are "projected in areas where future generator retirements are expected before enough replacement resources are in service to meet rising demand forecasts" (NERC 2023). Their Reliability Assessment released in December of 2023 "provides clear evidence of growing resource adequacy concerns over the next 10 years," as shown in Figure 3.

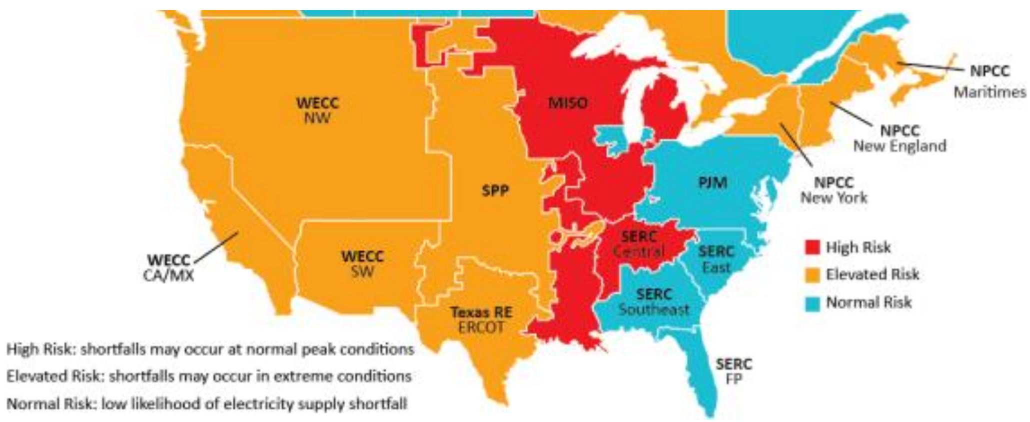

Figure 3: Risk Area Summary 2024-2028. *Source*: NERC 2023.

In addition to the significance and timeliness of the consideration of the capacity value of building decarbonization programs, we also consider their environmental attributes – a feature that has increased in value tremendously over recent years and is projected to continue this trend, as organizations advance their efforts to meet regulated and voluntary commitments to emissions reductions. Evidencing this trend, in late 2023, the U.S. Environmental Protection Agency (EPA) released an updated analysis of the value of avoided CO_2 emissions, estimating the avoided costs to be four times higher than previously estimated at $204 per metric ton for emission year 2023 (EPA 2023). Using commonly accepted conversion factors for average metric tons of CO_2 per kWh reduced of 6.99 × 10-4 metric tons CO_2/kWh (EPA 2024) combined with the updated societal costs, the equivalent value of the avoided emissions would be approximately $0.14/kWh reduced.

[1] While capacity shortfalls are a significant contributor to the reliability risks identified in the report, additional interrelated factors – such as extreme weather, transmission constraints, and generator energy limitations – also contribute to the conclusions reached in the assessment.

In other words, the value of societal costs of avoided emissions is more than two times *greater* than the national average value of traditional DSM program avoided energy costs. This value proposition could significantly help any emissions-reducing DER programs to expand impacts if there were a mechanism for utilities to monetize the benefits, and therefore reliably incorporate them into their cost-effectiveness assessments – as explored in this paper.

Further, as we consider other private sector investors in decarbonization (beyond energy utilities), the Taskforce on Scaling Voluntary Carbon Markets (TSVCM), sponsored by the Institute of International Finance (IIF) has predicted that voluntary markets for carbon credits will increase by a factor of 15 or more (relative to 2019 values) by 2030, with low-end scenarios reflecting a market value in the range of $5 billion to $30 billion by the present decade's end (TSCVM, 2021). Not only is overall market size increasing, but clear price differentiation can be noted for carbon credits sourced from technology-based projects (preferred) relative to nature-based projects. Investors' interest in real, measurable, and verifiable procurement of environmental attributes to reach net zero is also evidenced by recent commitments from both Google and the U.S. federal government to manage their operations and procure environmental credits such that the energy consumption of their buildings is carbon free on an hourly basis ("24/7 CFE"). These commitments will require environmental attributes to be temporally and locationally matched with the interested organizations' energy consumption, creating an opportunity for building decarbonization projects to fill valuable holes in emissions profiles of buildings that cannot be addressed (temporally and locally) by large-scale clean energy generation. The noted market price differentiation and 24/7 CFE commitments have largely occurred *in advance of* legal scrutiny of environmental attributes or regulation governing such claims in the U.S.. However, steps toward such governance can be found in: 1) the U.S. Securities and Exchange Commission (SEC)'s proposed rules regarding climate-related disclosures for investors (SEC 2022), 2) the World Resources Institute (WRI)'s revision of their guidance found in the GHG Protocol Corporate Standard to strengthen the rigor and consistency of reporting," (WRI 2024), and 3) the U.S. Internal Revenue Service (IRS) guidance released in December of 2023 related to qualification criteria for tax credits for the production of clean hydrogen (IRS 2023). Altogether, these recent commitments, procurement trends, and steps toward governance portend significant market opportunity for environmental attributes that can be measured, verified, and targeted toward specific times and locations of interest to investors.

While evidence suggests that the value of both the grid capacity and environmental benefits of building decarbonization projects are increasing, we also see significant diversification among the market actors that are administering large-scale building decarbonization incentive programs. Specifically, the federal funding for building decarbonization projects authorized and expanded under the Bipartisan Infrastructure Law (2021) and IRA (2022)[2] is making its way to the public via various actors including tribes, state energy offices, local education agencies, local governments, nonprofits, and private financing institutions, among others. Many of these new building decarbonization program administrators (unlike many energy utilities) lack experience and often lack inherent interest and resources to measure and monetize the value of the grid and environmental impacts associated with the projects they are incentivizing. Without tighter integration of these emerging programs with local energy utilities, it is unlikely that the grid impacts of these projects will be reliably tracked and reported, for appropriate reflection in utilities'

[2] Including the IRA Home Energy Rebate Programs, Tribal Electrification Program, Renew Americas Schools, Renew Americas Nonprofits, EE Conservation Block Grant Program, EE Revolving Loan Fund Capitalization Grant Program, the Greenhouse Gas Reduction Fund, and more.

resource planning processes. Better yet, utilities can be proactive by providing information regarding grid needs to these third-party program administrators *in advance of and throughout* implementation, in order to incentivize impacts in line with these system needs (i.e., load additions in locations and times of low system utilization, and load relief on constrained circuits or during peak times of day). Further, ownership of environmental attributes associated with these projects must be clearly and fairly established and tied to environmental commodity markets, where appropriate, so that program administrators or participants can capture the value of these attributes. These issues are explored in the following sections of this paper, with the significance of transparent and consistent accounting practices summarized in Figure 4.

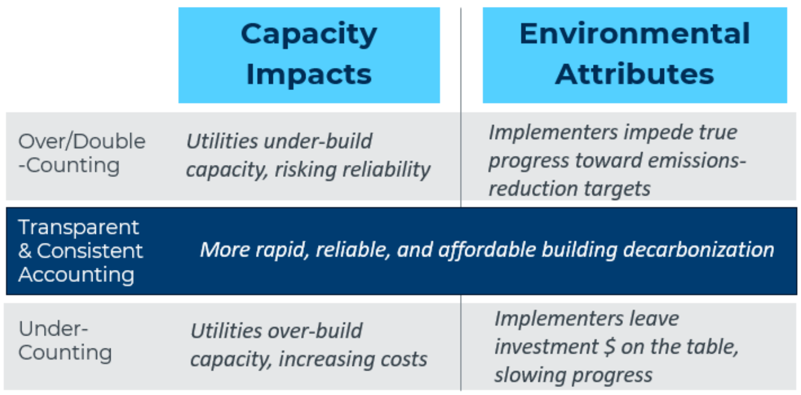

Figure 4: Importance of Transparent and Consistent Accounting for Capacity and Environmental Benefits of Building Decarbonization Projects

Capacity Accreditation and Markets

Historically, DSM programs (as a large subset of programs presently recognized as DER and building decarbonization programs) have been oriented around the primary objective "to provide cost-effective energy and capacity resources to help defer the need for new sources of power" (EIA 2024). Consistently, U.S. electric utilities' (and their regulators') determinations of appropriate investments in DSM programs have been dominated by consideration of avoided energy and capacity costs (Figure 2). The logic is that it is more cost effective for utilities to pay their customers to consume less energy during peak times than it would be to build new or larger power plants. However, the ways in which different utilities actually account for the grid impacts of DSM programs in their capacity and energy planning and procurement processes (i.e., the ways in which they actually *realize* the projected capacity and energy benefits of these programs) vary depending on a variety of factors, including the type of utility, the extent of services they provide as a regulated monopoly, and the rules governing resource adequacy (RA) from their respective regulating bodies, among other factors.

Changing Resource Adequacy Framework

As described by the National Association of Regulatory Utility Commissioners (NARUC), RA is "a measure of whether there are sufficient electric resources available to serve customer demand. Methods, metrics, and approaches for measuring RA can serve to inform… how much new generation should be built, and which generation can be taken out of service with consideration for the potential local and regional reliability impacts" (NARUC 2023). Here, we consider utility practices related to managing RA, including load forecasting and procurement of capacity resources, as they relate to DSM programs.

Commonly, to maintain RA, energy utilities – or in some cases, their independent system operator (ISO) / regional transmission organization (RTO) (Figure 5) or state regulatory body – develop gross load forecasts for their systems based on historical load data, with forward-looking adjustments made for weather and economic or market conditions that are expected to influence load. The EIA Annual Energy Outlook (EIA 2023) is a standard and commonly cited reference used by utilities to inform these adjustments to their gross load forecasts. For example, EIA 2023 explains that their modeled growth in residential heat pump installation *does* account for the impact of national tax credits extended by the IRA but *does not* explicitly include forecasted impacts of the IRA Home Energy Rebate Programs. Utilities often refer to these modeled demand-side impacts that are incorporated in their *gross* load forecasts as "naturally occurring." Alternatively, the impacts of utilities' programmatic efforts to advance market transformation and accelerate adoption of certain technologies or behaviors through their DSM programs are often subtracted (or netted out) of their gross load forecasts to produce a *net* forecast. This net load forecast is then increased by a planning reserve margin (PRM) which can be thought of as a buffer to maintain system reliability (10-17%, on average). That net forecast + PRM is then used by the utility to determine the load that they must be prepared to serve in a given year. In this way, the forecasted impacts of utilities' DSM programs reduce the amount of capacity and/or energy that they must develop/generate or procure in a given year, resulting in avoided costs.

While the impacts of most utility DSM programs are accounted for in this manner (i.e., on the "demand side" by netting out of the utility's load forecast), some wholesale electric markets (Figure 5) include alternative participation models for EE and DR to be accredited as capacity resources, which may be bought and sold in formal capacity markets. Of the ISO/RTOs shown below, only PJM, NYISO, ISO-New England, and MISO operate formal capacity markets. Under these constructs, utilities could[3] instead use the EE and DR resources to meet their forecasted load + PRM (i.e., account for them on the "*supply* side").

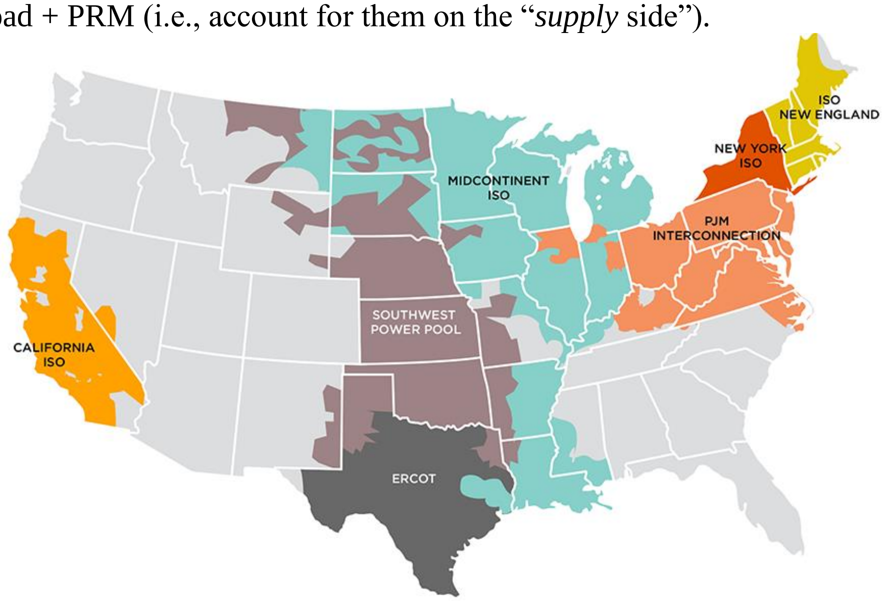

Figure 5: Map of U.S. ISOs and RTOs. *Source:* Sustainable FERC Project 2024.

[3] While such supply-side accounting is theoretically possible for member utilities of ISO/RTOs with formal capacity markets, it is an uncommon approach (with demand-side accounting generally preferred), for various reasons, including recent scrutiny over policies governing qualification of these resources in both MISO and PJM.

With this understanding of the status quo, we now explore key trends in the management of RA in the U.S. relevant to DSM programs[4] in order to contextualize emerging challenges and recommendations for improved accounting for their grid benefits.

Historically, planning for RA as an electric utility meant identifying the peak load hour or handful of hours on your system – often, a summer afternoon – and ensuring you had sufficient generating capacity contracted to meet those hours (minus the forecasted impacts of your DSM programs, plus a PRM). The capacity value attributed to each supply-side resource in this evaluation (i.e., its "accredited" value) would be closely tied to the resource's nameplate generating capacity, with adjustments for forced outages. Presently, shifts in this RA framework can be observed on both the demand side and the supply side of the equation. Driven by demand-side electrification, changing climate, constraints on our energy delivery infrastructure, and an evolving generation resource mix (i.e., aging legacy generators and increasingly intermittent and energy-limited renewables), among other factors, system planners are now applying additional scrutiny to load forecasts and the deliverable capability of supply-side resources to manage RA.

Specifically considering the energy limitations of the evolving generation fleet, RA is no longer synonymous with *capacity* adequacy and must incorporate considerations of *energy* adequacy; this is to say that not all megawatts (MWs) are created equally, as some generators are capable of delivering energy at near-full capacity for 5,000 hours per year, while another similarly-sized resource may only be capable of generating for 1,500 hours per year due to weather or other energy limitations. Further, not all megawatt hours (MWhs) are created equally, as some may be dispatchable and/or capable of supply at times of high system need, while others may be non-dispatchable and/or poorly aligned with system need. For these reasons, risks to RA may be introduced if system planners were to continue to subtract from a system load forecast a blanket MWh or MW total impact attributed broadly to DSM, without thorough consideration of factors including 1) the energy availability and dispatchability of DR programs, 2) the actual hours per year in which non-dispatchable EE program impacts are likely to be realized, and 3) the locations of these impacts on the utility system. Accordingly, designers and implementers of these DSM programs must expect increased attention and accountability on the granularity with which we measure and report on these components of our programs.

Emerging Value of and Drawbacks to Supply-Side Accounting

Accounting for DSM programs on the demand side is logically consistent with the impacts that most DSM programs achieve – i.e., reductions in demand, as opposed to additions of generating capacity and/or injections of energy onto the grid. However, supply-side treatment of certain DER programs is increasingly worthy of consideration as: 1) these programs evolve to include distributed renewable energy generation and battery technologies (which may be capable of injecting energy onto the grid); 2) traditional approaches to evaluating DSM investments independently/distinct from supply-side investments has been found to result in under-investment in DSM (LBNL 2023); and 3) third-party program implementers (i.e., non-utility actors who do not have a load forecast to subtract from) continue to scale up their activities and seek mechanisms to account for the grid impacts of their programs (Advanced Energy United 2021).

[4] We focus on DSM programs in this section for the sake of simplicity, though many of these topics are relevant to DER programs more broadly.

Illustrating these trends, as states within the MISO and SPP footprints (Figure 5) realize capacity constraints (Figure 3) and seek to prepare for the implementation of Federal Energy Regulatory Commission (FERC) Order 2222[5], regulators are formally considering (and in some cases, taking action to institute) the removal of existing restrictions on activity of third-party DR aggregators from implementing programs independently of a formal partnership with the local utility. One state engaged in this activity is Michigan, where aggregators operating independently of local utilities have a mechanism via MISO to accredit the capacity of their DR programs and transfer the value of these grid impacts to the local utilities via "zonal resource credits," which can then reduce the need for the utilities to procure alternative capacity. By contrast, where third-party DR program aggregators operate in states such as Kansas and Oklahoma, the SPP (unlike MISO) lacks a capacity market or alternative construct for third parties to accredit and transfer their DR program capacity to the utilities that serve these participating customers. While the true capacity value of the aggregators' DR portfolios is dependent on the dispatchability and energy limitations of the resources, as described in the prior section; any non-zero value that is *not* accredited and transferred to the utility (assuming it is cost-effective) introduces a risk that utilities will over-build more expensive capacity, increasing costs for all customers. This nascent issue merits attention not only from similarly-situated states such as Missouri and Arkansas, who are experimenting with or contemplating actions to enable third-party DR program implementation, but also all states developing regulatory frameworks to address the implementation of FERC Order 2222 and planning for the rollout of the IRA Home Energy Rebate Programs – two important drivers of scaled third-party DER program implementation – which, absent clear mechanisms for implementers to accredit and transfer the capacity value of these resources to utilities, risks adverse impacts on utility ratepayers.

While the prior statement indicates support for some form of supply-side treatment of DER programs to accommodate third-party program implementers, experience gained in MISO and PJM markets offers caution. MISO has historically permitted EE to participate as a resource in their voluntary capacity market. In 2022, concerns were raised regarding double-counting of EE capacity and the ability of market participants to ensure that capacity accredited as a resource (on the supply side) is excluded from consideration in the utilities' load forecasts (on the demand side) (MISO 2022). In December of 2023, PJM identified similar concerns related to incorporation of EE in load forecasting and ambiguity around what qualifies as an EE resource, as well as concerns regarding inconsistency and potential for bias in EE resource measurement and verification (M&V) processes (PJM 2023). While the capacity value of EE programs is undoubtedly existing and significant, it is evident that any attempt to account for EE as a supply-side resource will require robust and consistent M&V as well as clearly defined safeguards against double-counting of impacts.

With respect to supply-side accounting for DR resources, the early months of 2024 have witnessed two headline-making scandals related to the gaming of M&V procedures, resulting in multi-million-dollar fines for companies offering artificially inflated capacity into MISO markets. And as ISO/RTOs follow a market-wide trend toward more stringent capacity accreditation procedures, the value attributed to DR resources in many markets is anticipated to be reduced to account for the energy limitations of many of these resources, as well as other

[5] This Order requires FERC-jurisdictional ISO/RTOs to create or demonstrate participation models for aggregators of distributed energy resources (including demand-side resources) to offer resource aggregations into regional wholesale electricity markets and be compensated for their services. More information: https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy.

energy-limited grid resources. Accordingly, as regulators contemplate the potential benefits of activity of third-party DER program implementers, and of supply-side accounting for DER programs in general, it is apparent that: 1) robust, consistent, and closely-monitored M&V procedures, 2) clearly defined safeguards against double-counting, and 3) proper consideration of energy limitations must be addressed in processes for capacity accreditation and transfer.

Scrutiny of Demand-Side Accounting

Recent scrutiny of claimed grid impacts (and associated financial benefits) of DER programs is not limited to those accounted for on the supply side. The overwhelming majority of utility DSM programs are accounted for on the *demand* side through reductions in utilities' load forecasts (i.e., "load modifier" treatment). Recalling the changing RA framework described in prior sections of this paper, the legacy approach to this demand-side accounting of DSM program impacts – i.e., subtracting a total MWh and/or MW value associated with DSM from a system load forecast – is problematic in that it fails reliably account for energy and dispatchability limitations of these resources. This is to say that the legacy approach can present risks to RA if the demand impacts associated with these programs are not delivered during the time periods, for the durations, or in the locations needed to mitigate the system peak and/or fill gaps in the grid resource mix (which are moving targets, in many regions, due to end use electrification and transformation of the generation fleet).

Historically, these granular considerations regarding the RA contributions of DSM programs have been overlooked, as load-modifying resources have not constituted a significant proportion of most utilities' capabilities to serve peak demand. However, as generating capacity tightens in the region due to retirement of legacy generators and more flexible load resources come online (e.g., cryptocurrency operations, mass-market DERs), the magnitude of DR capacity on the system has grown relative to the capacity served by conventional generators, as has the proportion of some utilities' dependence on this DSM capability to maintain RA. Various ISO/RTOs across the country have noted the risks that this trend presents to maintaining system-wide RA; and SPP in particular has proposed corresponding reforms that (if accepted) would effectively eliminate most if not all present DR programs from qualifying as load modifying resources (to be accounted for on the demand side). Instead, these resources would be routed to pursue accreditation on the supply side and would likely realize significant de-rating in their valuations (due to the energy and dispatchability limitations noted above), while taking on new performance requirements. It is evident that a status-quo approach in SPP (as well as other markets now pursuing capacity accreditation reform) would likely result in dangerous over-valuation of DSM resources with constrained contributions to system reliability. However, it is important that these reforms are pursued in a manner that continues to provide program implementers with a pathway to maintain or develop offerings with acceptable terms and stable price points for participants, as we explore in the following section.

Additionally, as we consider limitations in demand-side accounting, it is important to note the granularity with which load reductions from EE programs are presently measured and reported. For many EE programs, the impacts of individual energy-saving technologies and behaviors (i.e., measures) are determined using a prescribed, average value established in a technical reference manual (TRM) or a single annual peak coincidence factor (CF) that is selected based on the end use category of the measure (e.g., lighting, space heating, cooling, process load, etc.) or building type (e.g. office, retail, warehouse, etc.). Simplifications such as these are undoubtedly valuable for achieving scaled market transformation. However, as utilities and their regulators expand their RA paradigms from planning for the peak load hour or hours on an annual basis, to planning for capacity and energy adequacy across seasons, taking into consideration changing load patterns with electrification and the interaction of the resource mix serving a given system, it will be important for EE program implementers to step up their game to remain an important part of the equation or risk being left behind. For example, for utilities facing new seasonal RA requirements, it will be important to understand the contribution of the EE portfolio not only to their annual system peak load (likely, summer), but also to the winter season and – in some regions – shoulder seasons as well. From the perspective of program implementers, this shift can be viewed not as a reporting burden, but an opportunity to assign some value to measures that have historically been shunned by EE programs due to their lack of coincidence with summer afternoon peaks – e.g., electric space heating and dusk-to-dawn lighting. Some guardrails for striking a balance between productive granularity and scale-squashing scrutiny are offered in the following section.

Recommendations

In light of this changing RA framework and related trends, we offer the following recommendations to inform future accounting for the grid impacts of building decarbonization programs. For utility regulators and other policymakers (especially those in capacity-constrained regions) that are: 1) contemplating and/or experimenting with efforts to enable increased activity of third-party aggregators of DERs in your jurisdictions, and/or 2) reviewing utilities' DER program proposals, we recommend that you work with stakeholders to reach a strong, shared understanding of the capacity accreditation and planning requirements for the utilities you regulate, as well as how the *potential* benefits (capacity, or otherwise) of this activity will be *realized*; failure to do so risks exacerbating capacity constraints and utilities' costs to serve all customers. As part of this process, regulators must consider and pursue clear processes and requirements regarding dual-participation in wholesale markets and utility retail programs and/or requirements for third parties to pursue full accreditation of their resources with the applicable entities and make the accredited capacity available for purchase to the relevant load-serving entities. This recommendation is *not* to dissuade regulators from taking action in this space; the inclusion of more actors implementing programmatic efforts to deliver grid and environmental benefits is undoubtedly a worthwhile effort. However, the complexity and rapid evolution of RA frameworks and specifically, DR resource accreditation procedures, presents meaningful risks to utility resource planning activity (and in turn, to ratepayers) if greater inclusion of non-utility actors in this space is pursued without accounting for these considerations.

For utilities, attend to RMI (2023) and LBNL (2023)'s guidance to treat DERs (including EE and DR) as selectable bundles in integrated resource planning activities. This will require a much higher degree of coordination between utilities' resource planning teams and customer programs teams. Under the legacy approach to DSM in RA frameworks, utilities' customer program teams may have interacted with resource planning teams by simply providing the forecasted MW and MWh program impacts for the planning years in question, which the resource planning teams would then incorporate in to the resource plan as a blanket reduction to the gross load forecast for the year (i.e., legacy load modifier treatment). Going forward, resource planning teams should seek to engage the designers and implementers of DER programs early in the process and on an ongoing basis, to educate the program teams on the system conditions for which they are planning and allow the program teams sufficient time to consider innovative program designs that may best address the anticipated grid needs. The realistic market potential and costs for potential program "bundles" should then be incorporated as selectable resources in capacity expansion modeling. Importantly, the timelines assigned to the forecasted impacts associated with these bundles should be reasonably aligned with DER program filing cycles or other avenues for utility investment.

For the implementers and evaluators of utility DER programs, at the program planning stage – even if only for internal awareness, at present – attempt to align the avoided capacity and energy cost values assigned to the resources procured through the programs with the operant capacity accreditation and RA frameworks, and historical, temporally-relevant energy cost data to the greatest extent feasible. For example, if RA is assessed seasonally, strive to designate a *seasonal* peak coincidence factor for each end use category or building type, and request a *seasonal* avoided capacity cost from utility resource planning teams; quantify and assign value to programs accordingly. Identify the highest-performing measures and programs under the revised framework and pursue industry best practices for increasing market uptake of those program elements. Additionally, while DR capacity accreditation is ongoing in many planning areas, activity to date has made it apparent that longer-duration and more frequent availability will result in greater capacity values. Accordingly, implementers and evaluators should work with sponsoring utilities to assign proxy forecasted capacity values in planning for years in which proposed policies are expected to take effect, in order to promote investment in accordance with expected system value. Program implementers and evaluators should also engage in this ongoing policy reform activity to ensure that planners and policymakers understand the bounds of customer preferences and capabilities on which DR capacity relies. Finally, implementers have an opportunity to be proactive in bringing customers along in this transition through education (e.g., describing peak periods not only as "hot summer afternoons," but also "cold winter mornings") and incentivizing technology enablement to support rapid response times and enable device orchestration over prolonged peak periods.

Environmental Attribute Certification and Markets

Energy Attribute Certificates (EACs) for DERs

The soaring demand for and associated market value of environmental attributes was established in the introduction to this paper, meriting consideration alongside the grid impacts of building decarbonization programs. However, definition and contextualization of these attributes is warranted before one may consider the merits and deficiencies of present systems that facilitate their certification and trading. To begin, we have used "environmental attributes" broadly to include two key subcategories of commodities – carbon credits and energy attribute certificates (EACs). Carbon credits are often generated through activities such as nature-based sequestration (e.g., reforestation) and technology-based removal of carbon dioxide from the atmosphere, among other activities; these credits are measured in units of carbon dioxide equivalent or CO2e, and are applied by organizations to offset their "scope 1" or *direct* greenhouse gas (GHG) emissions from sources owned or controlled by the organization (e.g., emissions from combustion in furnaces, vehicles, etc.). Alternatively, EACs – the focus of this section – are applied by organizations to offset their "scope 2" emissions, which constitute the GHG emissions associated with the generation of purchased electricity that is consumed by the organization. Accordingly, EACs are measured in units of energy (e.g., MWh) and are most often sourced from utility-scale renewable energy development projects. While EACs are commonly referred to as renewable energy certificates (RECs) in the United States, EAC is the umbrella term applied by the World Resource Institute's GHG Protocol to incorporate similar European certificates referred to as Guarantees of Origin (GOs) and leaving room for resource types beyond those that have been traditionally associated with RECs – here, DERs.

Most utilities are familiar with EACs because their states require a certain percentage of electricity delivered to customers to be sourced from renewable generation facilities, referred to as Renewable Portfolio Standards (RPSs). The way that utilities show compliance with RPSs is by purchasing the EACs from renewable generation and retiring them, thereby making a unique claim to the ownership of the environmental attributes. Corporations also purchase EACs (directly, through their electric utilities via "green tariffs," or through alternative intermediaries), in order to make a similar, albeit voluntary, claim to mitigate their scope 2 emissions. Some states, including Massachusetts (MA), Michigan (MI), North Carolina (NC), and New York (NY), have expanded their RPS constructs to explicitly include DERs, including peak load reduction programs and renewable thermal generation (e.g., heat pumps).

While those in the DER program space understand that these resources can offer similar (and in some cases, enhanced) environmental attributes relative to utility-scale renewable energy resources, it will likely not come as a surprise that standard and transparent mechanisms for assigning value to these attributes and enabling their purchase are lacking. For context, the EPA provides a useful overview of North America's REC tracking systems, shown in Figure 6, which they describe as "the preferable method for tracking wholesale renewable energy because they can be highly automated, contain specific information about each MWh, and are accessible over the internet to market participants (EPA 2024).

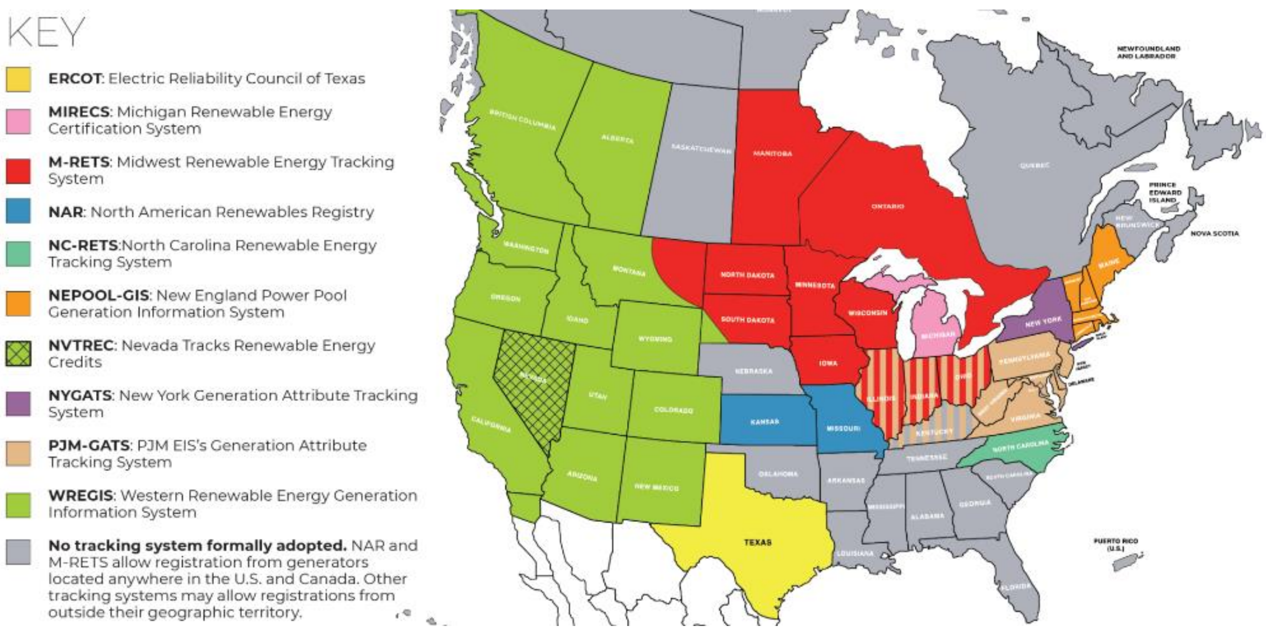

Figure 6: Renewable Energy Tracking Systems in North America. *Source*: EPA 2024.

However, notable drawbacks to the use of these tracking systems at present include the fact that individual retail electric customers generally do not hold accounts with these tracking systems, limiting their abilities to participate in these market mechanisms, absent an enabling green tariff through their utility or the support of other wholesale intermediaries. Further, while these systems are increasingly capable of managing expansive attribute data related to each EAC (e.g., specific resource type, location, etc.) they generally lack the data required by more sophisticated EAC buyers who seek to demonstrate time- and locational-matching of their EACs to the actual consumption of their facilities, as well as *incrementality* (an term akin to *attribution* in the DER program world). Each of these key drawbacks of current EAC market mechanisms limits the ability of this existing infrastructure to scale to facilitate meaningful certification and trading of EACs sourced from building decarbonization programs.

Beyond these drawbacks applicable to the tracking of all EACs, the certification of environmental attributes associated with DERs presents unique challenges. The first and most obvious challenge is one of scale. DER program implementers and evaluators manage MWh impacts on an annual basis and watt-hours (Wh) on a project-by-project basis. The tracking systems that are designed for large solar or wind projects do not scale cleanly to incorporate many smaller projects, indicating that DERs may require subordinate tracking systems. Secondly, ownership of demand-side EACs is unclear. Existing DER program terms and conditions can present challenges to market actors seeking to leverage EACs and utility incentives for DER project financing at scale. For example, the fine print of one central U.S. utility's EE program guidelines states, "[the utility] has the sole ownership interest in, and right to, any… environmental credits that may be associated with the EE measures for which… incentives were received, and [the utility] may dispose of such credits in any manner authorized by law or regulation." However, many DER programs are silent on the topic of EAC ownership – a worthy topic for further examination. Given these challenges, it is evident that industry-standard system(s) of record and transparency regarding EAC ownership are crucial steps in a path toward reliable and uniform accounting for EACs of DERs.

In response to increased market demand for granularity, transparency, and verified impact, non-governmental initiatives have started to form around standards that allow for voluntary procurement of EACs by private actors. EnergyTag emerged out of Europe to create a framework for issuing granular EACs for energy generation and storage. LF Energy's Carbon Data Specification project created a set of standards for utilities to report customer data and for grid operators to report generation data, allowing for use cases like hourly matching of EACs to the energy consumption of the procuring entity. Existing EAC registries like M-RETS and PJM-GATS have committed to providing hourly certificates, while new registries like WEATS are building Wh-based systems of record to enable DERs to be tracked alongside traditional generation resources. Recognizing that voluntary markets need a credible framework for M&V of claimed impacts, new initiatives like the OpenEAC Alliance promise to unlock voluntary EAC procurements by requiring peer-reviewed M&V as a prerequisite for EAC issuance.

Existing DER programs stand to benefit from this influx of activity related to voluntary EAC procurement. With local market knowledge, existing relationships with customers, and supply chains honed across years of engagement, these programs stand as the critical connection point between voluntary markets for EACs and energy management needs for utilities; the ability of program implementers to transparently and consistently value stack heralds a new era of investment into these resources.

Recommendations

For utility regulators and other policymakers (especially those who enable utilities to claim non-energy benefits associated with environmental attributes of their DER programs), consider requiring utilities to explore the options available to them to directly *realize* avoided costs from these attributes in implementation by measuring, verifying, and certifying EACs, and then report on these activities. Additionally, policymakers in states with RPSs or other clean energy goals under which utilities have compliance requirements, establish clear pathways for DER projects to qualify, following the leadership offered by MA, MI, NC, and NY.

For utilities and utility program implementers, as a first step on this journey – seek to understand the extent to which you currently own and/or claim or report on the EACs generated by your DER programs. Building on this understanding, participate in the development of M&V standards through the OpenEAC Alliance or other industry groups, and be intentional about your program terms and conditions regarding environmental attributes (i.e., only claim what you intend to certify and monetize). Further, if you *do* own the environmental attributes and do *not* presently take action to certify and monetize them, explore the potential value of these attributes by determining your regulating body's stance on counting them toward your RPS (if applicable) and/or analyzing any unmet demand for EACs that may exist among your customer base. If a defensible monetary value can be established for potential EACs under one or both of these pathways, analyze the potential impact that this incremental incentive could make if layered into the value stack of your existing DER incentives. Where this analysis indicates that certification is worthwhile, look to OpenEAC Alliance or other industry groups to identify an appropriate M&V methodology for your given program. Once established and reviewed by industry peers, pilot emerging applications for proven incentive structures (e.g., bonus incentives, tiered incentive rates) to drive increased adoption of higher-impact measures and programs. Note that this approach will likely require more granular systems than are often in place to account for and retire EACs on behalf of the sponsoring utility and/or customers.

Discussion

While the market trends, policy activity, and regulatory challenges introduced here may be intimately familiar to many in the electric utility industry, these topics may feel a step removed or only tangentially related to the specific work of those in the customer DER programs space. Those in the latter roles, instead, have likely spent the vast majority of recent years' strategic planning efforts focused on transitioning legacy programs beyond their decades-long reliance on lighting savings toward more expensive and complicated technologies, while continuing to achieve stable or increasing goals *and* maintaining cost-effectiveness, as narrowly measured by a local regulatory body. The great news here is that the evolution in underlying DER program values explored here – from the bedrock value of grid impacts to the emerging value of environmental attributes – promise an opportunity to address these challenges *and* amplify the impacts of your programs, to steer the industry toward levels of investment required to achieve our decarbonization goals while maintaining grid reliability. For example, by moving from summer-only to seasonal capacity valuation of EE measures, implementers in many regions may be able to assign additional value (and incentive) to under-utilized end use categories, such as space and water heating, helping to drive market interest. Even more powerfully, by establishing procedures to certify the environmental attributes of building decarbonization projects, program administrators open the door to additional funding streams, allowing interested buyers such as large corporations to layer in complementary incentives for capital-intensive projects (such as heat pumps and energy storage) in exchange for ownership of resultant EACs. In summary, as we as an industry contemplate "what's next after lighting" and "the future of utility programs," we urge you to look beyond alternative measures and end-use categories to see the evolving grid conditions, emerging revenue streams, and bustling ecosystem of market actors that are actively shaping the path through the coming decades of building decarbonization programs toward our shared goals as an industry and a society.

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