

Pathways to Meeting Growing Electricity Demand Through Expanding Customer Choice: A Review of Emerging Hybrid Power Choice Policies and Practices

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Abstract

State policies determine the degree to which commercial and industrial electricity customers can choose specified power supplies in the United States. Policies that enable customer choice have helped customers to manage electricity costs and achieve sustainability objectives. Customer choice could also mitigate the risk of increasing electricity demand leading to higher retail electricity prices. Here, we explore how state-level policies have resulted in varying degrees of power choice in the United States. We focus on 18 states in the western and southeastern U.S. without wholesale power markets or retail electricity competition. These states have implemented hybrid policies such as utility green tariffs and direct access provisions that grant customer choice to subsets of commercial and industrial customers. We explore how these hybrid choice policies have expanded power choice and helped commercial and industrial customers to manage costs and achieve sustainability objectives. We posit that expanded customer choice could complement other measures to mitigate potential impacts from rapidly increasing electricity demand on retail electricity prices.

1. Introduction

In the United States, most commercial and industrial (C&I) electricity customers buy a default retail electricity service provided by regulated utilities. Many C&I customers have some degree of choice over the types of resources used to generate their electricity. Customers exercise choice by buying power from alternative non-utility suppliers or buying alternative supplies from regulated utilities. Customer power choice varies with state policies and electricity market structures. As discussed in further detail in Section 2, about two-thirds of C&I demand has access to power choice through wholesale power markets or competition among retail electricity suppliers (EIA 2025). Customer power choice is limited for the remaining third of C&I demand without retail competition or wholesale power markets (Villareal, Chandler et al. 2025), notably in the

west and southeast. Still, power choice exists in these states to varying degrees due to the development of policies to enable choice for certain customers, or what we will refer to as “hybrid” choice policies.

C&I customers have advocated for expanded power choice primarily to manage power costs and achieve sustainability objectives (Borenstein and Bushnell 2015, O’Shaughnessy, Heeter et al. 2021, Shawhan, Witkin et al. 2022, Rose, Taruffelli et al. 2024). Utilities can use power choice programs to manage grid upgrades and achieve grid reliability objectives (ICF 2025). More recently, growing electricity demand from new “large load” customers has created a potential new use case for customer choice. New large loads such as hyperscale data centers have peak demand on the order of hundreds of megawatts (Martin and Peskoe 2025), the equivalent demand of a mid-size city. Electricity demand from data centers may triple from 2024 to 2028 (Shehabi, Smith et al. 2024). Rapid C&I demand growth can affect electricity system costs and can thus affect retail electricity prices. C&I demand growth through 2023 may have reduced prices by spreading fixed system costs over larger sales volumes (Wiser, O’Shaughnessy et al. 2025). However, by 2025, evidence has emerged that C&I demand growth may be increasing prices in certain regions (Jacobs 2025, Kunkel 2025). Several analyses suggest that future C&I demand growth could increase retail electricity prices if the system is unable to cost-effectively respond with system upgrades such as new generation resources and transmission and distribution infrastructure (Chandramowli, Cook et al. 2024, Martin and Peskoe 2025, Norris, Profeta et al. 2025). Some utilities and utility regulators are responding to large-load demand with new rate structures and regulations (Collier and Lindemann 2025, Satchwell, Mims Frick et al. 2025). These new regulations generally include measures to allocate incremental costs to new large loads and protect existing ratepayers from price increases. As shall be explored in further depth in this paper, some large-load reforms expand customer power choice, suggesting a potential role for power choice to complement measures to mitigate potential impacts of C&I demand growth on retail electricity prices. Further, power choice may enable existing C&I customers to continue to achieve cost and sustainability objectives as new large loads increasingly demand scarce generation resources.

This article documents the growth of hybrid choice and provides a resource for states that may continue to explore hybrid choice policies. We begin with a brief background on customer power choice in the U.S. (Section 2). We then provide an inventory of 5

hybrid choice policies in 18 states and discuss relevant details of the policies that enable hybrid choice (Section 3). We analyze the degree to which hybrid choice policies have facilitated customer power choice, to date (Section 4). We conclude with a discussion of hybrid choice, its role in managing corporate power costs, its role in enabling corporate sustainability, and a hypothesis about its potential role in mitigating the system cost impacts of growing C&I electricity demand (Section 5).

2. Background

Until the late 1990s, all U.S. retail electricity service was provided by vertically integrated utilities. Beginning in the late 1990s, the Federal Energy Regulatory Commission (FERC) ordered states to introduce market competition into the power generation sector (Joskow 2006). FERC-driven power market restructuring resulted in the development of six wholesale power markets, and Texas implemented a seventh market outside FERC jurisdiction, collectively covering the geographic extent of roughly two-thirds of the contiguous United States (Figure 1). Wholesale markets enabled power choice by allowing customers to choose wholesale power supplies from non-utility suppliers or to contractually procure power directly with generators (such contracts are possible outside of wholesale markets, but wholesale markets substantially facilitate such contracts). Some large corporations such as Google and Meta have also sought FERC approval to register as market participants and buy power directly from wholesale markets (Google 2016, Skidmore 2025). Market restructuring also resulted in 13 states implementing policies to allow competition among electricity suppliers to serve retail electricity customers (a 14th state, California, initially implemented but subsequently repealed retail competition). In retail-competition states, all customers can choose non-utility retail electricity suppliers. In 2024, data from the U.S. Energy Information Administration (2025) indicates that about 67% of C&I demand (in terms of kWh purchased) in the contiguous U.S. is in wholesale power markets, and that about 34% has access to both wholesale markets and retail competition (Figure 1).

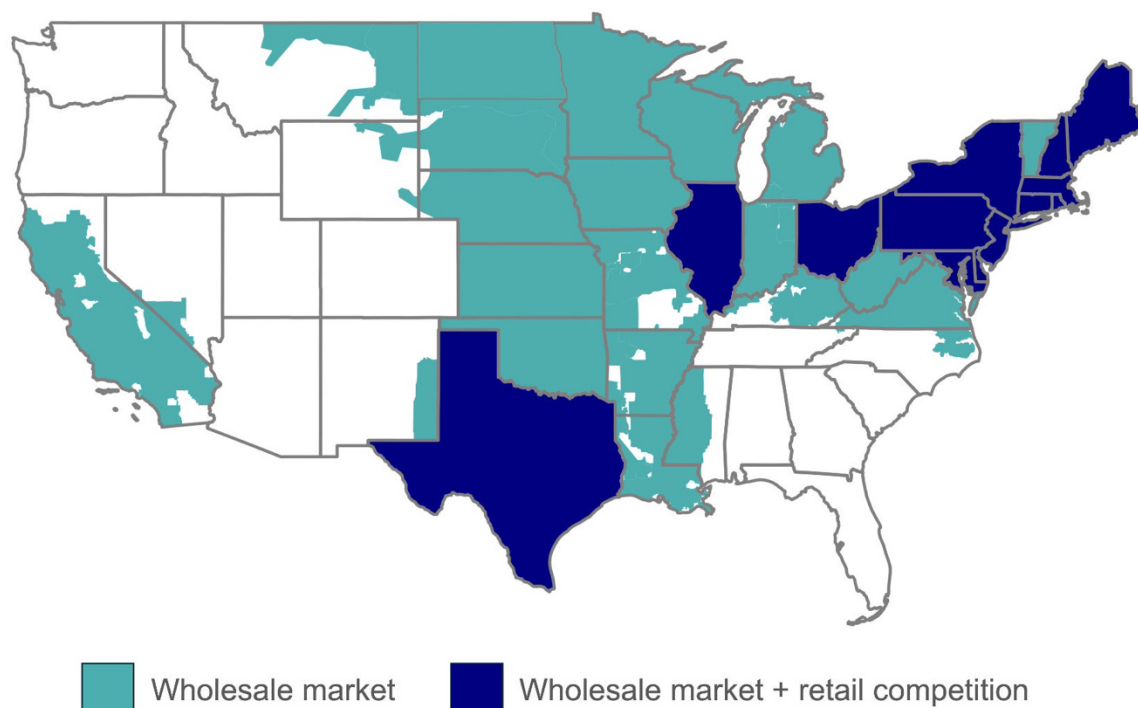


Figure 1. Wholesale power markets and retail competition in the contiguous United States

Power market restructuring was largely promoted to reduce grid system costs through market competition in the generation sector (Joskow 2006, Fabrizio, Rose et al. 2007). The evidence suggests that market restructuring yielded modest grid cost savings, though the effects on retail electricity prices have been muted (Fabrizio, Rose et al. 2007, Borenstein and Bushnell 2015, Rose, Tarufelli et al. 2024). Power market restructuring has also enabled customers to increase the renewable energy content of their power supplies (O'Shaughnessy, Heeter et al. 2021, Shawhan, Witkin et al. 2022). Organized wholesale power markets and, to a lesser extent, retail competition underpin C&I customer renewable energy procurement strategies such as power purchase agreements, where customers enter bilateral contracts with renewable energy generators. In 2024, U.S. electricity customers bought around 120 million megawatt-hours (MWh) of renewable energy through power purchase agreements and competitive retail electricity suppliers (O'Shaughnessy, Jena et al. 2025), equating to about 3% of all retail electricity sales.

Market restructuring stalled in the 2000s for several reasons, including the California energy crisis (partly attributed to restructuring), rising wholesale energy prices that curbed the potential economic benefits of restructuring, and strong political opposition,

especially in the west and southeast (Joskow 2006). U.S. power market fundamentals have remained largely the same since that time, with the country split between regions with wholesale markets with or without retail competition and regions with limited customer power choice. As depicted in Figure 1, gaps in wholesale market coverage exist in the west and the southeast. In those regions, there are 18 states where most C&I customers are outside of wholesale market boundaries: Alabama, Arizona, Colorado, Florida, Georgia, Idaho, Kentucky, Mississippi, Montana, New Mexico, Nevada, North Carolina, Oregon, South Carolina, Tennessee, Utah, Washington, and Wyoming. As a result, around one-third of C&I demand in the United States lacks access to wholesale power markets or retail competition. In an analysis of the degree of customer choice across states, Villareal et al. (2025) assigned grades on an A-F scale to all states based on the degree of power choice. None of the 18 states in this sample were graded above a C, and 12 of the 18 states received a D+ or worse under Villareal et al.'s analysis. Still, as demonstrated in the following section, some degree of power choice is available in all 18 states through hybrid choice policies. We explore these hybrid choice pathways in the 18-state sample in the following section.

3. A review of hybrid choice policies

For the purposes of this paper, hybrid choice refers to policies that enable power choice in states without wholesale power markets or retail competition. We group hybrid choice policies into five categories (Table 1): utility green tariffs (Section 3.1); direct access (Section 3.2); community solar (Section 3.3); distributed energy resource (DER) colocation (Section 3.4); and community choice (Section 3.5). Our discussion of these five options is ordered by the estimated magnitude of sales under each approach, as discussed in Section 4, with utility green tariffs being the most-used approach and community choice being the least used in the 18-state sample. As noted in Table 1, hybrid choice policies can enable two types of choice: the ability to choose alternative power suppliers or the ability to choose alternative supplies from monopoly utilities. Community solar and DER colocation can enable both types of choice depending on state policy, as discussed in Sections 3.3. and 3.4. Table 1 also discusses how the various measures protect against price impacts on non-participants, i.e., those customers that do not or cannot choose an alternative supply. These protections will be a key theme for our Discussion in Section 5.

Table 1. Summary Descriptions of Hybrid Choice Policies

Hybrid Choice Policy	Description	Choice Type	Price Protections for Non-Participants	Restrictions
Utility green tariffs	Multi-year contractual agreements allowing eligible C&I customers to procure specified resources owned by or under contract with the utility	Alternative utility supply	Tariffs stipulate terms to ensure participants bear incremental costs	Requires multi-year contracts; generally available to all C&I customers that meet defined criteria
Direct access	Carveout allowing eligible C&I customers to procure power from non-utility suppliers	Alternative supplier	Regulatory approval is conditional on demonstration of limited impact on non-participants	Typically only available to relatively large C&I customers (see Table 2)
Community solar	Customers procure power from a shared solar array	Alternative supplier or utility supply, depending on state policy	Community solar bill credits may contain cross-subsidies, regulators must ensure such cross-subsidies are just and reasonable ^a	The relatively small size of most programs ^b restricts value for relatively large C&I customers
Distributed energy resource (DER) colocation	Customers host DERs and use output	Alternative supplier (customer- or third-party owned DERs) or utility supply (utility-owned DERs), depending on state policy	DER system adoption can create rate recovery issues that may affect non-participant prices, regulators must ensure that such impacts are just and reasonable ^a	State laws on third-party ownership, DER compensation
Community choice	Community entity procures power from non-utility supplier on behalf of community residents	Alternative supplier	Regulatory approval can depend on compensation (e.g., exit fees)	Requires enabling legislation

^a “Just and reasonable” is the specific terminology often applied in rate design. All rates include some degree of cross-subsidization. Regulators are responsible for ensuring that existing cross-subsidies do not

impose undue burdens across customer classes. ^b About 98% of community solar projects are smaller than 10 MW (Xu, Chan et al. 2025);

Table 2 provides a high-level summary of these hybrid choice models in the 18 states in our sample. It is important to note that these hybrid choice policies exist outside of our 18-state sample, such as utility green tariffs in Michigan, direct access in Virginia, community solar programs in Minnesota, DER programs in Massachusetts, and community choice in California, to name just some key examples. Every state in the 18-state sample offers at least one pathway for C&I power choice. Hybrid choice policies can provide a substitute for conventional choice pathways (e.g., wholesale markets, retail competition). This point is depicted in Figure 2, which plots the availability of the primary hybrid choice pathways (direct access and utility green tariffs) across the contiguous U.S. Some form of direct access is provided in 14 of the 36 states without retail competition. Utility green tariffs are available in 16 of the 18 states where most C&I customers operate outside of wholesale power market boundaries.

Table 2. Inventory of Hybrid Choice Policies in Study Sample

State	Utility Green Tariffs	Direct Access	Community Solar ^a	DER Regulations ^b
Alabama	Alabama Power, Tennessee Valley Authority (TVA)			PURPA, third-party ownership prohibited
Arizona	Arizona Public Service, Salt River Project, Tucson Electric Power		Utility programs	Net billing, third-party ownership authorized
Colorado	Xcel Energy	>3 MW	Utility and third-party programs	Net metering, third-party ownership authorized
Florida			Utility programs	Net metering, third-party ownership prohibited
Georgia	Georgia Power, TVA	>900 kW	Utility programs	Net billing, third-party ownership authorized
Idaho	Idaho Power	>20 MW	Utility programs	Net billing
Kentucky	Lexington Gas & Electric, TVA		Utility programs	Net billing, third-party ownership prohibited
Mississippi	TVA			Net billing

Montana	Program in development at Northwestern Energy ^c	>5 MW	Utility programs	Net metering
New Mexico	Public Service Company of New Mexico		Utility programs	Net metering, third-party ownership authorized
Nevada	NV Energy	>1 MW	Utility programs	Net billing, third-party ownership authorized
North Carolina	Duke Energy, TVA		Utility programs	Net billing, third-party ownership prohibited
Oregon	Portland General Electric, Pacific Power	>30 kW	Utility and third-party programs	Net metering, third-party ownership authorized
South Carolina	Dominion Energy, Duke Energy		Utility and third-party programs	Net billing, third-party ownership prohibited
Tennessee	TVA		Utility programs	PURPA
Utah	Rocky Mountain Power	>100 MW	Utility programs	Net billing, third-party ownership authorized
Washington	Puget Sound Energy	>1 MW	Utility and third-party programs	Net metering
Wyoming	Black Hills Energy	>5 MW		Net metering

^a Based on program capacity data by subscription marketer type (utility or third party), data from Xu et al. (2025); ^b Based on information from the Database of State Incentives of Renewables & Efficiency (DSIRE 2025). See Section 3.4 for discussions of net metering/billing and TPO; ^c Available information suggests this program was not operating at the time of this publication, we exclude this program from our counts in Section 3.1.

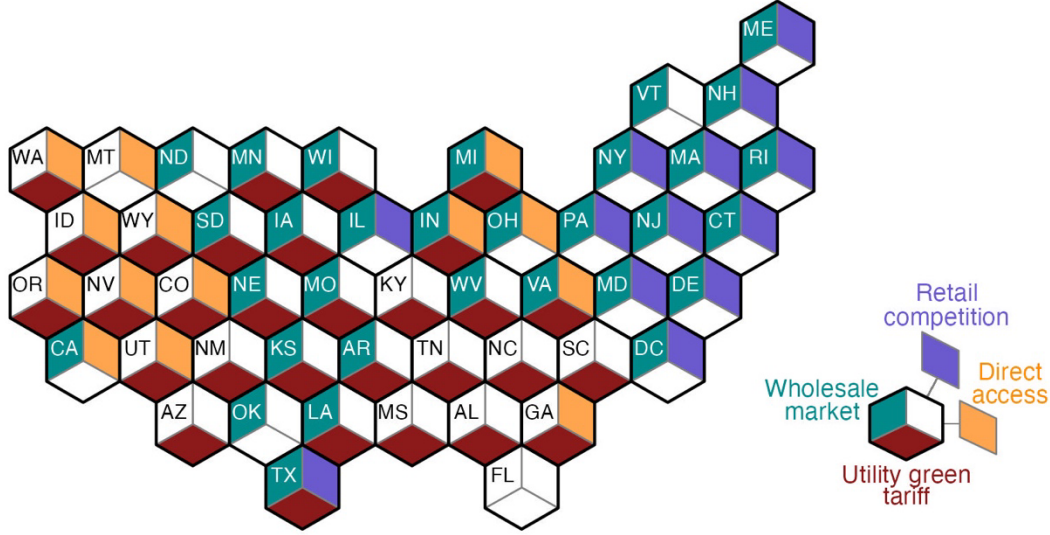


Figure 2. Availability of primary conventional choice pathways (wholesale markets, retail competition) and hybrid choice pathways (direct access, utility green tariffs) by state. For the purposes of this figure, wholesale power markets are mapped to states based on whether at least half of C&I customers in those states operate within wholesale power market boundaries. The availability of retail competition and direct access is based on information from Villareal et al. (2025) and our own research of state regulations. The availability of utility green tariffs is based on information from CEBA (2023).

Throughout the following sections we focus on examples of hybrid choice models in the 18-state subsample. In each sub-section, we select a case study of a hybrid choice policy that could provide a template for other states, with an emphasis on policies that could mitigate the impacts of increasing C&I demand.

3.1 Utility green tariffs

Utility tariffs are agreements between utilities and regulators that define the contractual relationships between utilities and their customers (throughout this paper, the term “regulators” refers to the entity responsible for electric utility regulation, typically a public utility commission). Utility tariffs define rate structures and other terms for broad customer classes, such as a tariff defining terms of service for all commercial customers operating in a defined region. In some cases, utility tariffs offer choice over utility supply by allowing C&I customers to procure power from specified resources owned or under contract with the utility. Resource-specific tariffs are commonly called utility “green” tariffs because they provide access to a subset of renewable resources, though utilities can offer tariffs for specified power from non-renewable resources. Utility green tariffs function like a power purchase agreement with the utility as

intermediary buying power from the generator and selling power to the C&I customer. The structure is often referred to as a “sleeved” power purchase.

Utility green tariffs have proliferated in recent years, largely in response to pressure from large C&I customers (O’Shaughnessy, Heeter et al. 2021). We identified 27 distinct utility green tariffs in 16 states of our 18-state sample. Utility green tariffs can be designed as bespoke agreements to meet the unique needs of specific customers. More often, utility green tariffs are available to all C&I customers that meet specified criteria, including the 27 programs explored here. Utility green tariffs vary in terms of customer eligibility criteria. Most utility green tariffs are restricted to C&I customers with at least 1 megawatt (MW) of peak demand. Utility green tariffs generally require multi-year contractual commitments from participating customers.

Utility green tariffs also vary in terms of the resources procured under the tariffs. Twenty (20) of the tariffs include options for tariff service from new renewable energy generators, and 16 of those programs require procurement from new generation. A key distinction across utility green tariffs is whether the utility or the customer prompts the development of new resources. Resource selection and development is led solely by the utility in 6 of the 20 tariffs with new development options in our sample. In these cases, the tariffs allow customers to choose an alternative power supply but do not allow customers to choose the specific supply characteristics. These tariffs often provide a way for utilities to propose new resources and use tariffs to enroll customers onto service from those resources. For example, Georgia Power’s Renewable Energy Development Initiative used a green tariff to develop a portfolio of 200 MW of new renewable resources. In contrast, eight tariffs in our sample specify that participating customers must prompt the development of new resources, and six tariffs include options for utility- or customer-driven development. For example, Idaho Power’s Clean Energy Your Way tariff includes a “construction” option under which the utility offers to develop and sleeve power from projects identified by participating customers. In cases where green tariffs allow customers to procure new resources, the tariffs generally stipulate that participating customers must bear all incremental investment costs of those resources.

The Nevada Clean Transition Tariff (CTT) provides an illustrative example of an innovative utility green tariff. The CTT illustrates many common features of utility green tariffs. Like many green tariffs, the CTT is the outcome of a collaboration between

a customer (in this case Google) and a specific utility (NVEnergy). The CTT defines a unique rate structure available to customers with at least 5 MW of monthly average demand. The CTT provides a pathway for customers to bring new resources online and procure supply from those resources via the utility. The CTT is unique among green tariffs in two regards. First, the CTT is designed to procure clean firm resources such as geothermal, as opposed to the variable resources of solar and wind supported by most green tariffs. Clean firm generation could be critical for deep grid decarbonization and for companies seeking to match clean generation to electricity use on an hourly basis. However, clean firm resource deployment is currently limited by the high costs of clean firm resources relative to solar and wind power generation. Utilities typically cannot obtain regulatory approval to invest in emerging clean firm technologies when cheaper alternatives are available. The CTT could solve that challenge by moving financial risks onto participating customers rather than the utility rate base. Second, the CTT is unique in its degree of cost protection for non-participants. All green tariffs include some degree of non-participant cost protection. For instance, NV Energy's existing GreenEnergy tariff requires that rates for participating customers must be at least greater than the otherwise applicable rate and that the tariff must protect non-participants. The CTT goes further by requiring participating customers to make long-term commitments equivalent to the lifetime of the clean firm generators (Wu, Silverman et al. 2024), in contrast to the one-to-five-year commitments required under the GreenEnergy tariff. Further, the CTT requires participants to post securities to guarantee contractual performance. The CTT is explicitly designed to pass all cost premiums and financial risks onto participating customers and to fully insulate non-participants from those risks (Flanagan 2024, Wu, Silverman et al. 2024). The potential use of green tariffs like the CTT for non-participant cost protection is a theme we explore in further depth in the Discussion. See Appendix A.1 for further details on the CTT.

3.2 Direct access provisions

Some states extended power choice to subsets of retail electricity customers during the initial phase of U.S. electricity market restructuring. These provisions are often known as "direct access," in contrast to full retail competition which extends choice to all customers. Direct access provisions typically define criteria under which C&I customers can seek generation services from non-utility suppliers. Eligible customers apply for

direct access from the state public utility regulator. Regulatory approval is generally conditional on a demonstration that direct access will not adversely affect non-participants. Regulated utilities remain responsible for transmission and distribution service.

Nine (9) of the 18 states in our sample have direct access provisions (see Table 2). Direct access eligibility varies substantially across the states, with peak demand thresholds defined as low as 30 kW in Oregon to as high as 100 MW in Utah. Direct access provisions may define various constraints on the ability of customers to leave utility service for alternative supplies. Common constraints include fees to switch to direct access (commonly called “exit fees”), restrictions on the ability of customers to return to utility service, and provisions to mitigate potential impacts on non-participants.

Utah provides a case study for the use of direct access as a hybrid choice policy to address increasing C&I demand. In 2025, the Utah state legislature passed Senate Bill (SB) 132 stipulating requirements for new large loads. SB 132 requires the state’s investor-owned utility to conduct a technoeconomic evaluation of its ability to meet requests to serve new large loads, defined as loads expected to exceed 100 MW of demand within 5 years. SB 132 requires the utility to notify large load customers of whether, based on this evaluation, the utility can meet the customer’s large load request. SB 132 stipulates that large load customers can procure service from non-utility providers if a) the utility fails to complete the evaluation within the required six-month timeframe or b) the utility and customer fail to negotiate a contract within 90 days from the completion of the evaluation. Regardless of whether the customer procures service from the utility or a non-utility supplier, SB 132 requires that all incremental costs be allocated to participating customers. Direct access customers are wholly responsible for all generation costs in contracts with non-utility suppliers and responsible for any transmission and distribution costs incurred by the utility.

Utah SB 132 is unique in two regards that may provide a template for hybrid choice policies in other states. First, under SB 132, regulated utilities remain the default service provider, but the rule establishes pathways through which C&I customers can request direct access to non-utility suppliers. That process is implicitly based, via the technoeconomic evaluation, on the utility’s ability to meet the C&I customer’s request. The legislation’s utility service default is distinct from direct access in other states such as Nevada, where qualifying customers can seek direct access regardless of the utility’s

ability to serve those customers. Second, the SB 132 size cap of 100 MW restricts the program to a relatively small class of very large C&I customers. For context, an average-sized natural gas plant in the U.S. has a rated power capacity of 85 MW (EIA 2024). The legislation is, at least implicitly, designed specifically to help integrate very new large loads such as data centers. Again, the high size cap will likely limit C&I power choice, in practice, as relatively few C&I customers will qualify to request direct access. Nonetheless, the large size cap may represent a practical compromise to make direct access viable in states that are unable to commit to broader options for direct access. See Appendix A.2 for further details on Utah SB 132.

3.3 Community solar

Community energy programs allow customers to pay special rates to procure power from specific energy projects. While community energy programs can be based on any energy resource, only community solar has achieved any meaningful scale in the United States, and we therefore focus exclusively on community solar. Community solar programs can be administered by utilities based on utility-owned assets or by third parties based on assets owned by non-utility entities. The third-party model is generally more common, with about 88% of community solar programs administered by third parties nationwide (Xu, Chan et al. 2025). However, community solar programs are evenly split in our 18-state sample between third party- and utility-administered programs, and utility-administered programs account for 91% of installed community solar capacity in the 18 states (Xu, Chan et al. 2025).

Community solar differs from utility green tariffs in that community solar may be based on third-party administered programs and projects. Another key distinction is that community solar programs are based on “subscription” models where any type of customer (including residential) can enter and exit the programs, whereas utility green tariffs involve multi-year contractual commitments and are restricted to C&I customers. Community solar also generally differs from utility green tariffs in three other regards: 1) some states allow non-utility suppliers to offer community solar products, while other states only allow utility-administered community solar, meaning that community solar can enable both types of choice (choice of supplier and choice of utility supply); 2) community solar programs typically source power from relatively small, “community scale” projects, typically meaning projects with less than 10 MW of capacity (Xu, Chan et al. 2025); and 3) community solar programs generally do not include explicit

provisions to protect non-participants from rate impacts. Community solar participants may be cross-subsidized by non-participants to some degree (Haynes, Kelty et al. 2020). State utility regulators are responsible for ensuring that such cross-subsidies are part of a just and reasonable rate design.

Community solar generally requires state policies or regulatory approval. At least 23 states have legislation to enable community solar, such as rules requiring utilities to offer virtual net metering, including 7 of the states in our sample (Xu, Nabirye et al. 2024). Many states further promote community solar by subsidizing community solar subscriptions, typically through revenues from solar renewable energy certificates. However, community solar is common in states without enabling legislation. Indeed, Florida is by far the state leader in terms of community solar program capacity, despite a lack of any enabling policy.

Florida provides a useful case study for community solar as a hybrid choice model for C&I customers. Florida utility regulators authorized the state's investor-owned utilities to develop two of the nation's largest community solar programs. The utilities were authorized to develop 51 solar projects each with nearly 75 MW of capacity (additional regulatory restrictions would have applied for projects larger than 75 MW). Unlike community solar in most other states, these projects are owned and operated by the state's investor-owned utilities. Some community solar advocates criticize the Florida community solar model for not allowing for competitive procurement, as is typical in most community solar programs (Gheorgiu 2020). Notwithstanding those critiques, Florida's community solar model provides a customer choice pathway in a state with otherwise limited options for C&I power choice. The relatively large size of Florida's community solar projects provide capacity to meet the demand of larger C&I customers. Outside of Florida, many states place system size limits on community solar projects (IREC 2020), and the average community solar project outside Florida has just 2.4 MW of capacity (Xu, Chan et al. 2025). The relatively large project sizes likely facilitated substantial cost savings through economies of scale. Further, the program offered by the state's largest utility reserved 75% of program capacity for C&I customers (Gheorgiu 2020). See further details on the Florida community solar model in Appendix A.3.

3.4 Distributed energy resource colocation

All retail electricity customers can supplement their grid power supply with on-site power generation, most commonly through small-scale fuel (e.g., diesel) generators and solar photovoltaics. Small-scale, customer-sited energy resources are commonly referred to as distributed energy resources (DERs). There are no regulatory constraints on the ability of customers to use power from customer-owned distributed energy resources. However, utility regulation applies to the ability of DER system owners to deliver power to the grid and the ability of customers to buy power from third-party owned DERs. In terms of grid exports, the Public Utility Regulatory Policies Act (PURPA) requires utilities to compensate DERs at a rate that reflects the utility's avoided costs (PURPA does not apply for systems larger than 80 MW). Among our 18-state sample, 16 states require utilities to compensate excess output under specified DER capacity limits at higher rates than required under PURPA (see Table 2). The details of these state-level requirements can significantly affect the economics of DER adoption. In terms of third-party ownership, the third-party ownership model allows customers to “host” DERs that are owned by third parties such as banks. The DER system hosts make ongoing payments for DER system output in lieu of purchasing the system hardware. Third-party ownership appeals to many customers because it allows customers to finance DERs and shift operation and maintenance responsibilities and system risks onto the third-party owners. Utility regulation generally prohibits third-party ownership because it entails electricity sales by non-utility suppliers. However, 29 states have explicitly authorized third-party ownership and 15 states have ambiguous regulation that can support third-party ownership in certain cases (DSIRE 2025). Only 6 states explicitly prohibit third-party ownership, including 5 states in our 18 state sample.

DER regulations generally do not contain explicit provisions to protect non-participants. DER adoption can exacerbate underlying challenges in rate design and can affect electricity prices paid by customers that do not adopt DERs (Wiser, O'Shaughnessy et al. 2025). Utility regulators are responsible for ensuring that price impacts on non-adopters are part of a just and reasonable rate design.

DER colocation has unique benefits among the hybrid choice pathways for facilitating the grid integration of new large loads. DERs co-located with new large loads can be operated flexibly in ways that serve the load while providing grid benefits (Norris, Profeta et al. 2025, Spector 2025). For instance, battery storage infrastructure at data

centers can be flexibly operated to maintain data center power supplies and provide grid ancillary services (Alaperä, Honkapuro et al. 2018, Türker Takci, Qadrdan et al. 2025). Utilities, regulators, and policymakers could therefore consider ways to enable DER co-location to increase the grid flexibility of new large loads (ICF 2025). One example in our state sample is Georgia Power’s Back-up Generation Solutions program. The program enables C&I customers to host DERs that are operated by the utility. The program stipulates that the utility will operate the DERs to benefit all customers. In exchange, the DER system C&I customer hosts can use the DERs for backup power during grid outages. The program allows participating customers to make a single upfront payment to host a utility-owned DER or to own the DER and receive bill credits for the DER’s estimated system value. The program is designed to support relatively large DERs and is thus presumably aimed toward relatively large C&I customers. For customers that own the DERs, the program requires a minimum DER capacity of 1 MW, or an aggregation of systems with at least 250 kW. For customers that host utility-owned DERs, the minimum capacity threshold is 10 MW. By way of comparison, a typical household rooftop solar system has less than 10 kW of capacity. See Appendix A.4 for further details on the program.

Customer interest in and uptake of the Georgia Power Back-up Generation Solutions program remains unknown. Nonetheless, the program illustrates one way that utilities and grid operators could use hybrid power choice to manage increasing C&I electricity demand. The program is explicitly designed to bring new resources online that benefit all customers. Because the utility owns the DER output, the program effectively prevents potential price impacts on non-participants, thus avoiding a common concern related to DERs. Participating C&I customers are compensated in the form of increased resiliency during grid outages and bill credits based on the system value of the DERs. Other states could explore if resiliency-based models could help utilities couple new loads with new resources that insulate non-participants from electricity price impacts. We return to this point in the Discussion.

3.5 Community choice

Community choice is a model where an entity representing a jurisdiction chooses a power supply on behalf of investor-owned utility customers in the jurisdiction. The entity is typically a non-profit group formed to represent the jurisdiction. Community choice is often called community choice aggregation or municipal aggregation,

emphasizing that the model aggregates the demand within jurisdictions for the purposes of procuring power. Community choice policies can include measures to prevent impacts of community choice on non-participating communities. For instance, California community choice legislation required participating communities to pay fees akin to the exit fees of direct access provisions.

The term “community choice” is generally understood to imply an ability to choose an alternative non-utility supplier. Supplier-based community choice is only possible when authorized by state law and had been authorized in 10 states as of November 2025. Supplier-based community choice is not authorized in any of the 18 states in our sample, though such legislation has been explored in Arizona, Colorado, New Mexico, and Washington (LEAN Energy U.S. 2025). However, broadening the concept of “community choice” to mean choice over utility supply widens the sample of states where community choice is possible. Even in states without authorized community choice of supplier, cities can leverage franchise agreements with utilities to pursue some degree of community choice over utility supply, such as in the case of Boulder, CO.

Utah provides a case study in community choice in this broader sense. In the 2010s, several Utah communities explored ways to enhance community choice, including conventional community choice aggregation and municipalization. These efforts prompted the passage of the Community Renewable Energy Act (CREA) in 2019. CREA opened a brief window in 2019 allowing Utah communities to request the state’s investor-owned utility to deliver 100% renewable energy service by 2030. Twenty-three Utah communities joined the program (Kunkel 2021), including the Grand, Salt Lake, and Summit Counties, meaning that at least one-third of the state’s population resides in participating communities (see further details in Appendix A.5). Participating communities agreed to bear the incremental costs required to achieve the 100% renewable energy target. Like conventional community choice aggregation, CREA allowed for an opt-out structure, where residents of participating communities are defaulted into the program but can opt out back into standard utility service (Kunkel 2021). The key distinction between the CREA model and conventional community choice is that the Utah communities cannot seek alternative suppliers; the communities can only request alternative supplies from the utility. The CREA model may provide a useful template for a hybrid form of community choice in states that are unlikely to pass legislation to authorize supplier-based community choice.

4. Participation in hybrid power choice models

This section summarizes C&I customer uptake of hybrid power choice models. For each state, we estimate C&I customer demand served under power choice models as a percentage of total C&I sales based on data from EIA Form 861 (2025). We input utility green tariff data based on state-level estimates for utility green tariffs from O'Shaughnessy et al. (2025). We estimate direct access sales based on Form 861 data for sales to retail and wholesale power marketers. We estimate community solar sales based on data from Xu et al. (2025). The data from Xu et al. do not distinguish between community solar sales to residential and C&I customers. We conservatively assume that 40% of community solar sales accrue to C&I customers in states other than Florida, based on typical anchor tenant restrictions in state-level community solar policies (IREC 2020). In contrast, we assume that 75% of community solar sales in Florida accrue to C&I customers, consistent with the state's program design (see Section 3.3). Finally, we estimate DER colocation uptake by using non-residential PV installation data from Barbose et al. (2024). Non-residential PV installations are an imperfect proxy for DERs, which include a broader class of technologies. Further, the data from Barbose et al. are not comprehensive, though the data typically capture more than 80% of PV system installations. We exclude community choice, given that supplier-based community choice is prohibited in our state sample, and there is no way to distinguish sales in Utah's CREA program from standard utility supplies to our knowledge. Figure 3 depicts customer uptake of the four hybrid choice models in the 18 states from 2019 to 2024, and Figure 4 depicts uptake across models by state in 2024.

Utility green tariffs are the fastest-growing hybrid choice model in terms of customer uptake. Nationwide, utility green tariff sales grew from around 1 million MWh in 2015 to around 22 million MWh in 2024 (O'Shaughnessy, Jena et al. 2025). Utility green tariff sales account for more than 5% of all C&I sales in three states in our sample (note that Montana is among these states due to an ad-hoc utility green tariff, though the state does not yet have a confirmed utility green tariff program as reflected in Table 2). Overall, an estimated 17 million MWh were sold through utility green tariffs in the 18 states, equating to around 2% of sales across the states. Utility green tariffs account for about 2.8% of C&I sales on average in the 18-state sample, significantly higher than the average of 0.6% of sales in other states ($t=2.9$). These statistics suggest that utility green tariffs provide a substitute form of choice in states without wholesale power markets or

retail competition, as likewise suggested by the spatial availability of green tariffs depicted in Figure 2.

Direct access sales accounted for more than 1% of C&I sales in 2024 in four states in the sample, reaching as high as 19% of all C&I electricity sales in Nevada in 2024. Across the 18 states, about 170 C&I customers procured around 10 million MWh in 2024 through direct access, or about 1% of all C&I sales in the sample. The data suggest that direct access sales have declined over time in these 18 states in absolute and relative terms (see Figure 3). Unlike in the case of green tariffs, direct access sales are far larger outside of the 18-state sample. While non-utility suppliers account for about 1% of C&I sales in the 18-state sample, non-utility suppliers account for about 6% of C&I sales in the 17 states with wholesale power markets but without retail electricity competition, and about 69% of C&I sales in the 13 states with retail electricity competition.

Community and on-site solar are substantially smaller than the other hybrid choice models in terms of estimated C&I customer uptake. Community solar is likely a niche product for relatively small commercial customers in most states outside of Florida (see Section 3.3). Still, overall we estimate that C&I customers procured about 6 million MWh of community solar in the 18 states in 2024, or about 0.7% of all sales. On-site solar procurement is of a similar magnitude, with an estimated 1.7 million MWh of generation in the 18-state sample in 2024 .

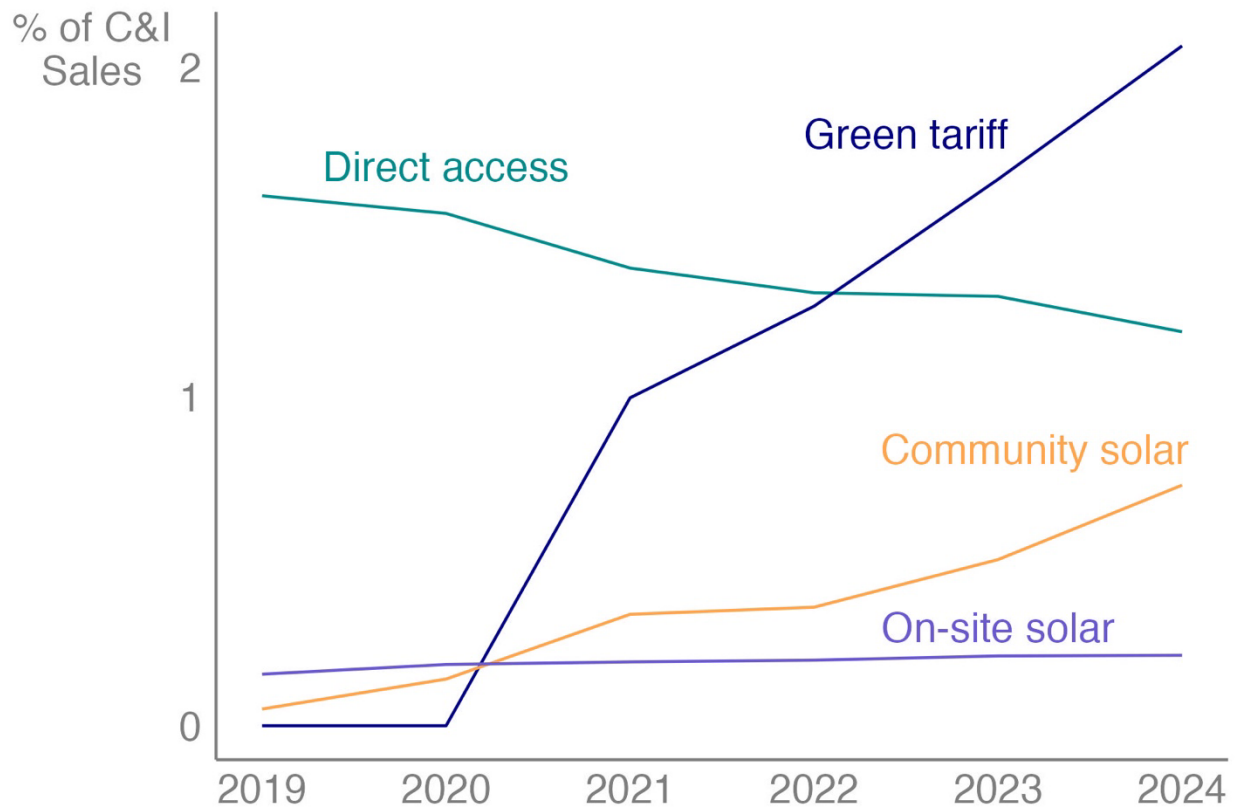


Figure 3. C&I customer uptake of hybrid choice pathways in 18-state sample, 2019-2024

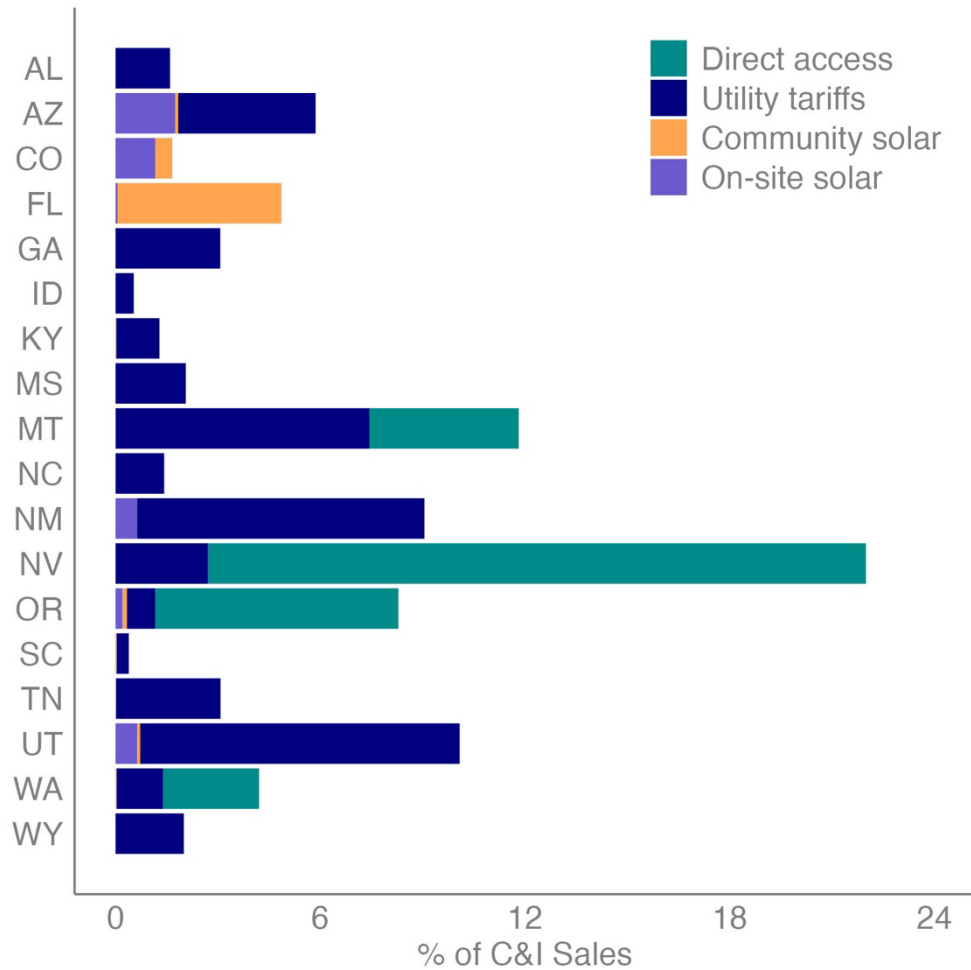


Figure 4. C&I customer uptake of hybrid choice pathways

C&I customer uptake of hybrid choice models varies substantially across the 18 states in our sample. We posit and explore two potential explanations for these disparities in hybrid choice sales. First, disparities in hybrid choice sales could reflect differences in the availability of hybrid choice models across states. That hypothesis is consistent with prior research demonstrating that an expansion of C&I renewable energy procurement pathways was associated with a similar expansion in C&I renewable energy procurement (O’Shaughnessy, Heeter et al. 2021). Similarly, an expansion of hybrid choice pathways within states may be associated with increased uptake of hybrid choice. The data are consistent with this hypothesis. Eight of the 18 states in the sample offer four of the five hybrid choice pathways described in Section 3 (see Table 2). The state-level average C&I customer uptake of hybrid choice in these 8 states in 2024 was about 2.4 times higher than in states with fewer hybrid choice pathways, though that

difference is not statistically significant ($t=1.7$). Second, the programmatic details of hybrid choice policies may affect C&I customer uptake. This hypothesis is supported by the relatively strong uptake of community solar in Florida, where the program is specifically designed for C&I customers. Further, C&I customer uptake of direct access programs is generally higher in states with lower customer eligibility thresholds. In the 4 states with eligibility thresholds no larger than 1 MW (GA, NV, OR, WA), direct access uptake in 2024 was about 7% on average, compared to 1% on average in the other direct access states, though again the difference is not statistically significant ($t=1.5$). However, the difference is clear and statistically significant when considering the impacts of full retail choice on C&I customer uptake. About 70% of C&I sales were from non-utility suppliers in states with full retail choice in 2024 (see Figure 1), compared to 19% of C&I sales in states in the contiguous U.S. without full retail choice ($t=5.3$).

5. Discussion & conclusions

Most U.S. states implemented some form of electricity market restructuring in the late 1990s into the early 2000s. These reforms resulted in the development of wholesale power markets and competition among retail electricity suppliers. Electricity market restructuring increased the ability of electricity customers to choose their power supply or supplier, especially among C&I customers. However, electricity market restructuring did not occur in 18 states in the west and southeast of the U.S.. Still, policymakers, regulators, and utilities in all 18 states have developed hybrid choice policies that enable varying degrees of customer power choice.

Demand for C&I power choice is largely driven by C&I customer interest in managing electricity costs and achieving sustainability objectives. Hybrid choice policies have helped C&I customers to achieve both objectives. In terms of C&I customer costs, the available evidence suggests power choice can help C&I customers more effectively manage electricity costs through access to more flexible rate structures (e.g., time-varying rates) and long-term contracts with alternative electricity suppliers (Borenstein and Bushnell 2015, Rose, Tarufelli et al. 2024). In terms of sustainability objectives, in 2024, the National Renewable Energy Laboratory estimates that C&I customers procured around 36 million MWh of renewable energy above state-mandated levels through utility green tariffs and direct access in our 18-state sample (O'Shaughnessy, Jena et al. 2025). Those C&I customers could have otherwise procured renewable energy through other pathways that rely largely on out-of-state resources, such as by procuring

unbundled renewable energy certificates or signing virtual power purchase agreements. However, the hybrid choice policies provide C&I customers with pathways to meet sustainability objectives through in-state resources, meeting the demands of many C&I customers for “local” renewable energy generation.

In 2024, we estimate that C&I customers procured about 34 million MWh through these hybrid choice pathways, representing about 4% of C&I demand in those states. C&I customer uptake of hybrid choice pathways varies substantially across the states in the 18-state sample. We estimate that sales through hybrid choice programs account for as much as 22% of C&I sales in Nevada to as little as less than 1% in South Carolina. We posit two hypotheses for these disparities in customer uptake and find suggestive evidence to support both. First, C&I customer uptake of hybrid choice correlates with the availability of different hybrid choice pathways. Different hybrid choice pathways may meet the specific needs of different customers. As a result, a greater variety of pathways would meet the needs of more customers and increase C&I customer uptake of hybrid choice models. Second, the programmatic details of hybrid choice pathways may affect customer uptake. For example, more restrictive customer eligibility criteria (e.g., larger minimum demand thresholds) will likely reduce customer uptake. We find suggestive evidence for both hypotheses. Future research could explore these and other hypotheses in further depth through more rigorous causal modeling, such as analyses of changes in C&I customer uptake before and after hybrid choice policy changes. Further, we find diverging trends in the uptake of different hybrid choice models. From 2019 to 2024, C&I customer uptake of utility green tariffs in the 18-state sample gradually increased, while customer uptake of direct access gradually declined. Future research could explore the drivers of trends in C&I customer uptake of hybrid choice across models.

In addition to helping C&I customers manage costs and achieve sustainability objectives, we posit that hybrid choice policies could mitigate adverse effects from rapidly increasing C&I electricity demand. That hypothesis stems from two observations from the hybrid choice policies summarized in Section 3. First, most hybrid customer choice programs include measures to mitigate the impacts of power choice on non-participants, meaning customers that do not or cannot choose alternative power supplies. Utility green tariffs can include contractual terms that allocate incremental costs to participating customers, and regulatory approval for direct access or

community choice can be conditioned on an assessment of impacts on non-participants. Existing hybrid choice policies do not necessarily mitigate cost risks to the same extent as emerging large load tariffs (Collier and Lindemann 2025), but such policies could be adapted for enhanced risk mitigation. The Nevada CTT, summarized in Section 3.1, may provide a useful template for ways to minimize non-participant risks in hybrid choice policies. Second, customer choice policies can be and often are designed to support the development of new resources. Utility green tariffs, in particular, are often designed to support utility procurement of new generation. We find that 16 out of 27 utility green tariffs in our geographic sample require service from new generation resources, and 4 additional tariffs include options for service from new generation. Direct access provisions can likewise be designed to support new resources, such as the Utah legislation explored in Section 3.2. As a result, hybrid choice policies can be designed to enable large C&I customers to deploy new generation resources that can facilitate integration of new large loads onto the grid, and hybrid choice policies can include safeguards to mitigate risks of cost impacts on non-participants. Many utilities already view customer power choice programs as a way to enable the development of new resources and reinforce grid reliability (ICF 2025).

Utilities and regulators are responding to rapid C&I demand growth by filing requests for and implementing new large-load tariffs (Collier and Lindemann 2025, Satchwell, Mims Frick et al. 2025). A collaboration of researchers, utilities, regulators, large-load customers, and other stakeholders identified a set of eight principles to guide the design of new large-load tariffs (Cannon and Wang 2025). Three of the principles emphasize the importance of allocating incremental costs to new large loads and protecting non-participants. One of the principles describes the need to define eligible resources, including generation, that will be “sourced or supported via utility procurements, bilateral [i.e., between customer and project] or trilateral contracting [i.e., between, customer, utility, and project], behind-the-meter and front-of-meter co-location arrangements, or other sourcing processes” (Cannon and Wang 2025). This principle identifies distinct types of customer choice as central elements of large load tariff design. Still, pathways for customer choice are not always clearly identified in emerging large load tariffs. We identified a sample of 28 tariffs requested or implemented in 24 states from July 2023 through October 2025. An exploratory analysis of this sample identified 10 tariffs that unambiguously identify pathways for new large loads to choose an alternative utility supply or to procure power from non-utility suppliers.

Future research could further analyze emerging large load tariffs to understand how customer choice is or is not being used to integrate new large loads onto the grid.

The hypothesis that hybrid choice could facilitate large-load integration requires further research. Large C&I loads with demand on the scale of whole cities remains a relatively recent phenomenon, and state responses to large-load growth are likewise nascent. New large loads are a distinct customer class in terms of their scale and their objectives. A key objective of data centers is so-called speed to power: accessing power as quickly as possible to rapidly deploy more data centers. The speed to power objective is strong enough that some new large loads are building off-grid natural gas generators to bypass lengthy grid interconnection processes (Hiller 2025). The speed to power objective is distinct from the cost and sustainability objectives of C&I customers that can be met through existing hybrid choice policies. It remains to be seen whether and how policymakers could adapt hybrid choice policies to meet the distinct needs of new large loads. Future research could explore C&I customer uptake of these emerging hybrid choice policies and how the design and implementation of these policies can mitigate the potential impacts of increasing C&I demand.

Researchers and policymakers may consider ways that distinct hybrid choice policies or other policies could be designed to simultaneously meet the distinct needs of existing C&I buyers and new large loads. Existing hybrid choice policies may continue to play key roles in enabling existing C&I customers to meet cost and sustainability objectives. In contrast to new large loads, existing C&I customers require far smaller power supplies, on the order of megawatts rather than hundreds of megawatts. The relatively smaller scale of existing C&I customers is more aligned with the sizes of typical solar and wind projects. For example, through the end of 2024, 86% of utility-scale solar projects in the United States were no larger than 100 MW (Seel, Mulvaney Kemp et al. 2024). Further, existing C&I customers do not have the same speed-to-power constraints as some new large loads such as datacenters. Without speed-to-power constraints, existing C&I customers may be better positioned to support the development of new solar and wind resources, given that such development generally takes multiple years. As a result, existing hybrid choice policies may continue to enable C&I customers to support the development of new solar and wind resources, in particular. A distinct suite of hybrid choice or other policies may simultaneously help new large loads to meet their own distinct objectives. These policies would need to support the development of

generation resources on the scale of hundreds of megawatts at a pace to meet speed-to-power objectives. Utility tariffs specifically designed for the risks of new large loads are one emerging solution. Other emerging solutions include utility green tariffs with enhanced non-participant protections (e.g., Nevada CTT), direct access for new large loads (e.g., Utah), and policies to support colocation of flexible DERs with new large loads (e.g., Georgia Power). Future research may explore emerging solutions for new large loads and how large-load strategies can complement hybrid choice policies for existing C&I customers.

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Appendix A. Hybrid Choice Policy Case Studies

A.1 Nevada Power's Utility Green Tariff

Nevada's Clean Transition Tariff (CTT), introduced in Section 3.1, is a utility green tariff approved by the Public Utilities Commission of Nevada on March 11, 2025. As discussed in Section 3.1, the CTT is unique in the extent to which the tariff mitigates the risks of retail electricity rate impacts. The CTT requires participating customers to make long-term commitments equivalent to the lifetime of the clean firm generators (Wu, Silverman et al. 2024), in contrast to the one-to-five-year commitments required under NV Energy's standard green tariff. Further, the CTT requires participants to post securities to guarantee contractual performance. The CTT is explicitly designed to pass all cost premiums and financial risks onto participating customers and to fully insulate non-participants from those risks (Flanagan 2024, Wu, Silverman et al. 2024)

The CTT supported an energy supply agreement between Google's subsidiary Callisto Enterprises and NV Energy's subsidiary Sierra Pacific Power Company. The agreement adds 115 MW of geothermal power to Nevada's grid to meet Google's objective of power one of its data centers with clean energy. The agreement stipulates that Google will receive electric service from Fervo Energy's Corsac Station Enhanced Geothermal Project, once it begins its commercial operation. NV Energy would buy electricity from Fervo's plant and sell it to Google at a price that is set at the difference between the cost of geothermal energy and lower-cost resources such as solar or natural gas (which NV Energy would have otherwise deployed under least-cost regulatory constraints). Additionally, Google would receive energy and generation capacity credits on their electric bills to offset demand charges from its nearby data centers. While Google is the only customer, to our knowledge, to pursue the CTT, the tariff is designed as an open program for all eligible C&I customers with at least 5 MW of monthly average demand.

A.2 Utah's Direct Access Provision

As discussed in Section 3.2, Utah's Senate Bill 132 (SB 132) introduces alternative electricity access methods for large load customers. SB 132 was introduced on January 16, 2025, signed by Governor Cox on March 25, 2025, and became effective May 7, 2025. It only applies to contracts commencing on or before December 31, 2034.

SB 132 applies to new large loads or expansions of existing loads that reach 100 MW of peak demand within five years. SB 132 establishes a series of steps to determine how the new large load will be served, as illustrated in Figure A.1. Under SB 132, the utility (Rocky Mountain Power in most of Utah) has the first right to serve new large loads. SB 132 requires the utility to conduct a technoeconomic evaluation of the system impacts of the new large load and to notify the customer of the utility's ability to fulfill the customer's request. SB 132 stipulates that large load customers can procure service from non-utility providers if a) the utility fails to complete the required evaluation within the required six-month timeframe or b) the utility and customer fail to negotiate a contract within 90 days from the completion of the evaluation. SB 132 specifies that all large load contracts (with utilities or non-utility providers) must "ensure that all large load incremental costs are allocated to and paid by the large load customer." The large load incremental costs required to be covered by the large load customer include generation resources, distribution system upgrades, transmission system improvements and network upgrades, interconnection facilities improvements, and other necessary infrastructure. In the case of utility contracts, SB 132 further requires "the large load customer to maintain financial security sufficient to cover the large load customer's obligations."

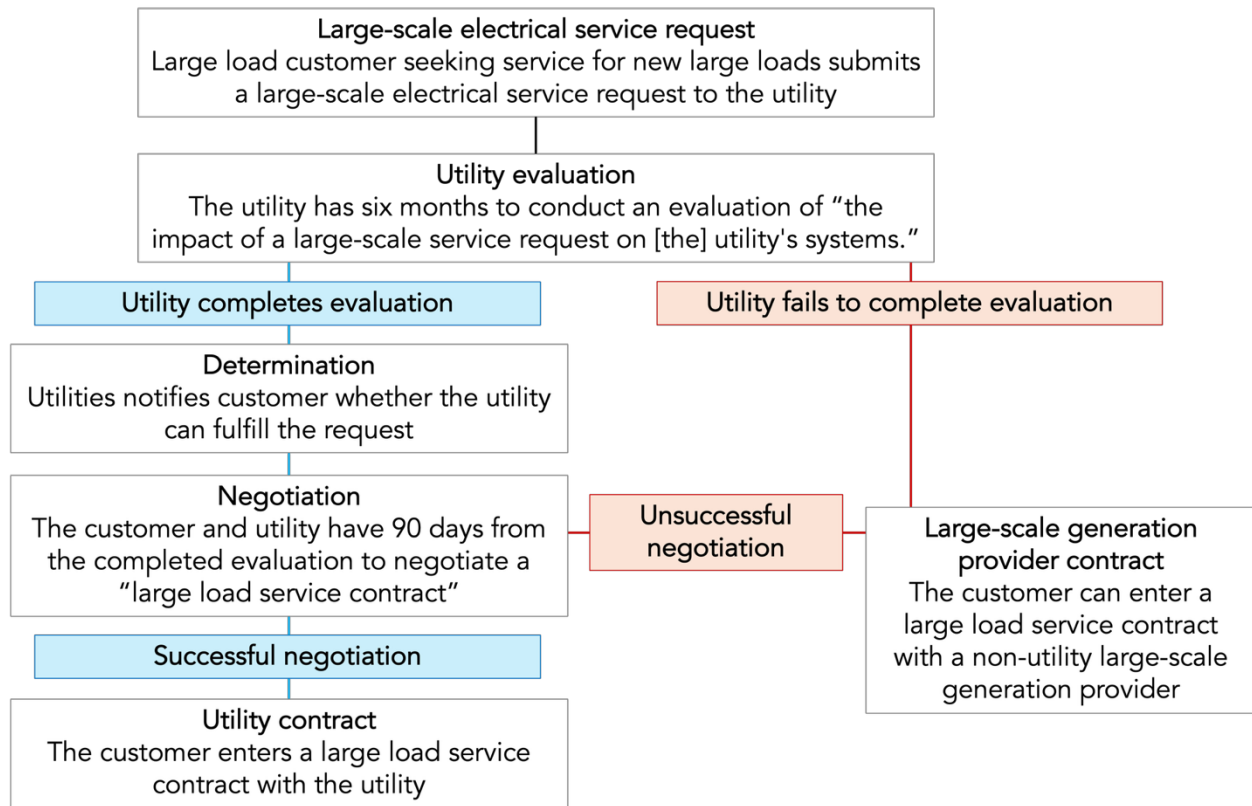


Figure A.1. Schematic description of Utah SB 132 large load service request process

A.3 Community Solar in Florida

Section 3.3 introduces two community solar programs in Florida that are owned and operated by investor-owned-utilities.

Florida Power and Light (FPL) operates the SolarTogether Program, and Duke Energy operates the Clean Energy Connection Program. Both programs are available to C&I customers with distinct restrictions. The FPL program is open to all C&I customers but restricts C&I subscriptions to 45% of energy usage, though C&I customers can request 100% of energy usage from the program’s waitlist for new capacity. The Duke program is restricted to C&I customers with less than \$250,000 in annual electricity usage. The C&I components of both programs were fully subscribed as of the drafting of this study (November 2025). The SolarTogether program continues to expand, with plans for 24 additional solar projects (1,788 MW of subscription capacity) to be developed in Northwest Florida, bringing total program capacity to 3,278 MW.

Participants in both programs select the number of 1 kW blocks they subscribe to, up to their previous 12-month total kWh usage (or the C&I limit in the FPL program). In the Duke program, for example, each block is associated with about two solar panels at a community solar facility and costs a fixed fee of \$8.35/kW per month. The initial bill credit rate is = ~\$0.04/kWh for the first 36 months (which may vary seasonally), with the rate increasing 1.5% annually at the 37th month of continuous enrollment. Higher savings are projected with longer involvement in the program.

A.4 Georgia Power's Distributed Energy Resource Colocation Programs

Georgia Power's Back-Up Generation Solutions Program comprises three DER offerings for C&I customers, two of which we detailed in Section 3.4. While each program differs in ownership model, payment method, and DER operations (Table A.1), they all share a similar structure of incentivizing DER hosting by allowing C&I customers to use DERs for resiliency during grid outages:

- **DER Customer Pilot Program: Resiliency Asset Service (RAS) and Demand Response Credit (DRC) Tariffs.** The RAS tariff allows C&I customers to host a utility-owned behind-the-meter DERs that provides resiliency services to the C&I customer host in exchange for fixed monthly payments based on the utility's costs to procure, operate, and maintain the DERs. In combination with the DRC Tariff, the DER can be used to directly serve C&I customer load during demand response events.
- **DER Colocation Program: DER Colocation Tariff (DCL).** The DCL allows C&I customers to host utility-owned front-of-the-meter DERs. DERs must be larger than 10 MW and located on the C&I customers' premises. Participating customers pay charges based on the utility's costs to procure, operate, and maintain the DER less 75% of the estimated lifetime DER system value. The DER system will then be installed, owned, and operated by Georgia Power to provide systemwide services. In return, the customer can use the DER for resiliency purposes during grid outages.
- **DER Customer Owned Program: DER Customer Owned Tariff (DCO).** The DCO allows C&I customers to procure and host front-of-the-meter DERs. Qualifying C&I customers host DERs between 1-10 MW on their premises, including aggregations of multiple accounts where each account is >250 kW. Upfront capital and installation costs are the responsibility of the customer.

Georgia Power operates the DERs to provide systemwide benefits. In return, the customer receives a monthly credit equal to 75% of the estimated DER system value. As of November 2025, customers can participate through 2031, though the program's required interconnection agreement may be extended by both parties based on the needs of the system.

Table A.1. Georgia Power DER Colocation Programs

	DER Customer Pilot (RAS, DCR)	DER Colocation Program (DCL)	DER Customer Owned (DCO)
DER Asset Ownership	Utility	Utility	Customer
DER customer value	Resiliency (RAS), demand reduction during demand response events (DRC)	Resiliency	Resiliency, bill credits
DER utility value	Demand response	Systemwide services (except during outages)	Systemwide services (except during outages)
DER position	Behind the meter	Front of the meter	Front of the meter
Eligibility	RAS: >200 kW annual peak load; DRC: >1000 kW of reducible demand (may be aggregated across multiple sites)	Installed asset nameplate capacity ≥ 10 MW	Installed asset nameplate ≥ 1 MW and < 10 MW, can aggregate if each is 250kW or greater
Customer participation costs	Bill charges based on utility-incurred DER costs	Bill charges based on utility-incurred DER costs less 75% of projected system value	Customer bears DER system costs (capital, operations, maintenance)
Customer credits	Bill credits for demand response	None	Bill credits equal to 75% of the estimated DER systemwide value

A.5 “Community Choice” in Utah

None of the 18 states in our sample have authorized community choice for alternative suppliers. Yet, as noted in Section 3.5, Utah has developed a hybrid policy that allows communities to exercise choice over utility supply. Utah House Bill 411, also known as the Utah Community Renewable Energy Act (CREA), was signed by Governor Herbert on March 29, 2019. The effort began in May 2016, when Salt Lake City, Summit County, and Park City entered a renewable energy and energy choice partnership. Their goal was to investigate pathways to enhance renewable energy resource development and examine the feasibility of community choice aggregation. A joint study commissioned by the group found that a renewable energy tariff through the state’s investor-owned utility Rocky Mountain Power (RMP) would be cheaper than implementing community choice aggregation as a pathway to achieving net-100% renewable energy. This group worked in partnership with RMP to pass the Utah CREA.

CREA requires interested municipalities served by RMP to adopt resolutions before December 31, 2019 that aim to procure 100% of the jurisdiction’s annual energy supply from renewable resources by 2030. Twenty-three (23) communities adopted resolutions by the deadline. Eighteen (18) of these 23 communities continued with this effort in 2022 through the formation of the Utah Renewable Communities (URC), also known as the Community Renewable Energy Agency. As of November 2025, there are 19 participating communities in URC (Figure A.2).

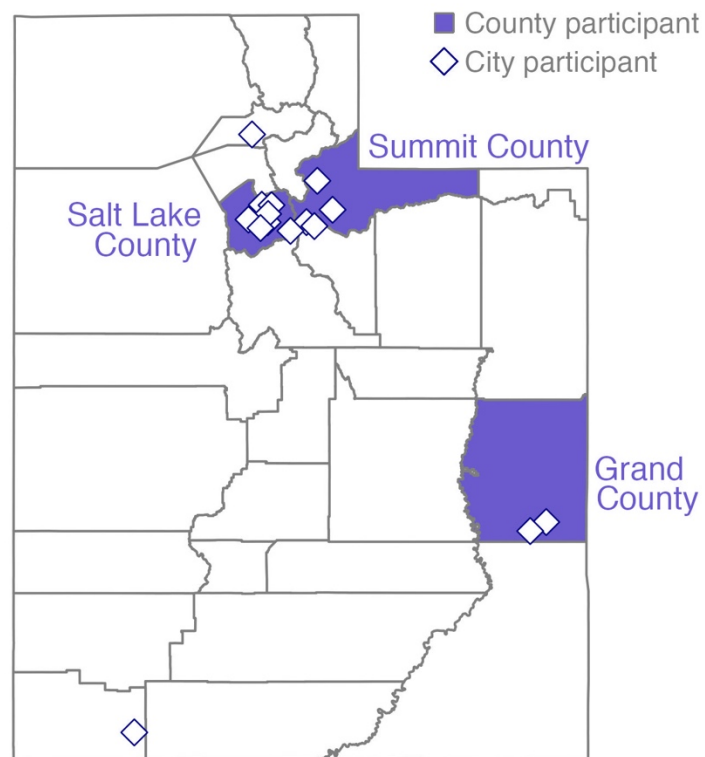


Figure A.2. Map of counties and cities participating in the Utah Community Renewable Energy Agency