POWERING PENNSYLVANIA: WHY CUSTOMER-GENERATION MATTERS NOW

Natural Gas, Distributed Energy, and a Balanced Path for the Commonwealth

A JOINT PROJECT OF:

PIOGA
Pennsylvania Independent Oil & Gas Association

T & F EXPLORATION

PENNECO ENVIRONMENTAL SOLUTIONS, LLC

KRIEBEL ENERGY

June 2026

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I. Introduction

Pennsylvania's electric system is undergoing a structural transition. Conditions like modest load growth, centralized generation, and long planning horizons have shaped the existing infrastructure in the Commonwealth. These conditions, however, no longer fully describe the environment in which energy policy decisions are being made. Electricity demand is rising at rates not seen in decades, while generation technologies continue to evolve and diversify. Together, these developments are placing increasing pressure on existing infrastructure and creating new challenges for maintaining reliability, affordability, and adequate supply in a rapidly changing energy landscape.

Across the PJM region, system operators project sustained increases in electricity demand over the coming decades, with summer peak load expected to grow significantly and total energy consumption rising as electrification, data centers, and other large loads expand.[1] These emerging load patterns reflect continuous, high-capacity consumption profiles placing new demands on system reliability and resource adequacy, which differ from the historical norms.

At the same time, expanding centralized generation and transmission infrastructure has become increasingly complex and time-intensive. Large-scale generation projects must navigate permitting, interconnection, and financing constraints, while transmission development often requires multi-jurisdictional approvals and extended construction timelines.[2] The result is a system in which traditional utility-scale supply-side solutions may not be capable of being deployed quickly enough to keep pace with growing electricity demand, while the substantial costs of these investments are ultimately borne by consumers through wholesale power prices, transmission charges, and other components of retail electric service. These dynamics are occurring against the backdrop of an electric grid that is already under strain. Pennsylvania's infrastructure includes aging assets and significant maintenance backlogs, all of which require continued investment to maintain reliability and resilience.[3]

Within this evolving landscape, distributed energy resources ("DERs"), including customer-generation, are playing an increasingly important role. DERs include a broad category of small-scale generation and storage technologies located at or near the point of consumption, including

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[1] PJM Resource Adequacy Planning Department, 2026 PJM Load Forecast Report (Jan. 14, 2026).
[2] See U.S. Dep't of Energy, *Distributed Energy Resource Interconnection Roadmap* (2025) (discussing interconnection delays and infrastructure constraints).
[3] Am. Soc'y of Civ. Eng'rs, *2022 Report Card for Pennsylvania's Infrastructure* (noting aging infrastructure and maintenance backlogs).

solar photovoltaic systems, energy storage, and on-site generation resources.[4] Unlike centralized generation, these resources are typically deployed at the distribution level, can serve local load directly with excess generation exported to the grid, and are privately financed. In Pennsylvania, the Alternative Energy Portfolio Standards Act ("AEPS Act") reflects a deliberate policy choice to encourage private investment in alternative energy generation by permitting qualifying customers to participate in the market as customer-generators rather than solely as consumers of utility-supplied electricity. Customer-generators finance, develop, and operate these facilities using private capital and, through net metering, receive credits at the retail rate for excess electricity exported to the grid.[5]

At the same time, distributed resources can provide system-level benefits, including reduced transmission losses, deferred infrastructure investment, distribution system support, and enhanced system flexibility when deployed at scale.[6] As their role in the electric system has expanded, the policies governing their compensation and integration have become increasingly consequential. Net metering and related compensation structures were originally designed to encourage private investment in distributed resources and to integrate generation closer to load.[7] As participation has grown, however, questions regarding how these resources should be valued, how costs and benefits should be allocated, and how distributed generation should be integrated into a system that continues to rely on centralized infrastructure have become topics of debate in rate cases and default service filings.

These questions arise from utilities' default service filings and rate cases, Public Utility Commission hearings, and even in the Pennsylvania General Assembly. Decisions about how customer-generators are defined, compensated, and incorporated into the grid will influence not only individual project viability, but also the Commonwealth's ability to attract private investment, maintain system reliability, and manage long-term costs.

This white paper examines these issues in the context of Pennsylvania's current and projected energy landscape. It considers how rising demand, infrastructure constraints, and the evolving distributed generation mix affect the role of the customer-generator within the system. It also evaluates how different approaches to compensation and policy design may influence the

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[4] ERCOT, *Distributed Energy Resources Operational Data: Value, Insights, and Technology Pathways for a Reliable Grid* (Aug. 2025).
[5] See 73 P.S. § 1648.5 ("Excess generation from net-metered customer-generators shall receive full retail value for all energy produced on an annual basis."); see also 52 Pa. Code § 75.13(d)-(e) (implementing annual excess generation compensation through Pennsylvania's net metering framework).
[6] Allan et al., *The Economics of Distributed Energy Generation: A Literature Review*, Renewable & Sustainable Energy Reviews (discussing T&D savings and system benefits).
[7] Aldebot, *Regulatory Issues for Distributed Generation* (Penn State 2022) (describing net metering's role in encouraging private investment).

availability of private investment in generation resources at a time when additional supply and system flexibility are increasingly necessary. Where demand is growing, infrastructure expansion is constrained, and capital requirements are increasing, the ability to attract and sustain private investment in generation resources—particularly distributed generation resources—becomes a central consideration.

II. The Evolving Role of Distributed Generation in Modern Electric Systems

For most of the past 100 years, the structure of electric power systems has been defined by centralized generation, long-distance transmission, and one-directional delivery of electricity to consumers. This traditional model was supported by economies of scale in generator size and a regulatory framework designed around large, capital-intensive utility investments, usually recoverable from ratepayers. Throughout much of the twentieth century, utilities achieved declining per-unit costs by building progressively larger thermal generating stations, often in the hundreds to thousands of megawatts, where fixed construction costs could be spread across a growing customer base and increased electricity consumption.[8] The current regulatory model allows utilities and wholesale power generators to recover these capital expenditures through rates and purchased-power cost recovery mechanisms while earning an authorized return on invested capital, creating a direct financial incentive to develop large infrastructure assets such as transmission lines, and substations.[9] In recent years, however, both technological developments and changing system conditions have expanded the role of distributed generation within this framework. In Pennsylvania, this evolution has occurred against the backdrop of electricity market restructuring, which separated electric distribution companies from generation ownership and increased reliance on competitive generation markets and privately financed supply resources.

DERs, which include customer-generation, energy storage, and flexible load, now represent a growing component of the electric system. Deployment of these systems has accelerated over the past decade. In the United States, residential distributed solar installations increased from approximately 89,000 systems in 2010 to more than 4.7 million by 2023, with nearly 800,000 installations added in 2023 alone.[10] Behind-the-meter solar capacity is projected to approach approximately 90 gigawatts by 2033, reflecting continued expansion of distributed photovoltaic systems.[11]

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[8] See Amory B. Lovins, *Small Is Profitable: The Hidden Economic Benefits of Distributed Generation* (Rocky Mountain Institute 2002) (discussing historical economies of scale in large thermal generation).
[9] See Suedeen G. Kelly & J. Porter Wiseman, *Creating a Regulatory Framework for Demand-Side Investment in the Distribution Grid Equivalent to Capital Investment in Generation* (2016) (describing cost-of-service regulation and capital recovery incentives).
[10] U.S. Dep't of Energy, *Distributed Energy Resource Interconnection Roadmap* (2025).
[11] N. Am. Elec. Reliability Corp., *Long-Term Reliability Assessment* (2023).

In certain regions, DERs have reached levels that influence system planning and operations. In some jurisdictions, distributed resources now account for between 5 and 15 percent of peak demand at the distribution level, with installed capacity measured in the hundreds to thousands of megawatts.[12] These levels of deployment require system operators and utilities to account for distributed resources not as marginal sources of supply, but as components of the overall supply portfolio. Utilities and their consultants are working hard to understand how to integrate distributed resources into resource adequacy planning, but much work remains to be done in gaining the experience necessary to take full advantage of distributed resources.

The economics of distributed resources are fundamentally different than those applying to utility-scale generation. Utility-scale generation historically relied on building larger facilities to achieve lower unit costs. Distributed resources, by contrast, derive cost reductions from mass manufacturing, standardized deployment, and technological learning. As more solar panels, batteries, inverters, and other distributed energy technologies are produced and installed, costs generally decline while system performance continues to improve. Distributed resources open an unprecedented opportunity for utilities to improve their granular understanding of the grid, and to target generation deployment to locations with highest value, including local economic value. Distributed resources demonstrate modularity, as they can be both right-sized and right-sited for maximum grid and economic benefits. Distributed resources are more labor intense and more widely siteable. In their variety and scale, they bring economic and tax base benefits to communities throughout the Commonwealth.

While distributed solar systems account for the majority of recent DER growth, distributed generation is not and has not been limited to renewable technologies. A substantial portion of distributed capacity consists of natural gas–fired systems, particularly combined heat and power ("CHP") and other small-scale generation technologies that provide dispatchable power near to variable load.

Dispatchable generation is generation that can be turned on or off or have its output level adjusted in short periods of time, depending on grid load conditions. The level of dispatchability and its proximity to load are key variables for grid managers. Because of system-wide losses and the complexity of maintaining balance for an entire grid, dispatchable distributed generation and storage are increasingly recognized as cost-effective tools for precision management of the grid.

In addition, more and better information technologies enable the collective management of numerous distributed energy resources to provide "virtual net metering" power plant performance while maintaining the right-sizing and right-siting benefits of distributed assets. These "Virtual

[12] *Id.*; see also NERC, *Reducing DER Variability and Uncertainty Impacts on the Bulk Power System* (2023).

Power Plants" are already approaching and exceeding the scale of traditional power plants.[13] Leveraging the power of portfolio management and eliminating the risk of single points of failure, aggregations of distributed resources can be designed to realize economic benefits on a few, a few dozen, or even hundreds and thousands of individual facilities.

In Pennsylvania, this dynamic is particularly important because conventional wells, also commonly referred to as marginal wells or stripper wells, comprise a substantial majority of the Commonwealth's producing wells. Individually, these wells produce relatively small volumes of natural gas and account for only a modest share of total statewide output.[14] As a result, many operate on thin margins and are highly sensitive to operating costs, commodity prices, transportation expenses, and access to gathering infrastructure. Under these conditions, the availability of additional revenue streams can determine whether continued production remains economic. Collectively, however, Pennsylvania's large population of conventional wells represents a significant energy resource that can support distributed electricity generation when developed at scale, creating a unique intersection between upstream energy production and distributed generation.

When paired with appropriately sized on-site generation, conventional well production can support distributed generation resources capable of operating at high capacity factors and producing electricity that is unaffected by weather conditions. That is, the basic engineering of such wells favors continuous levels of operation, which means that associated power generation has a smoothing effect on grid conditions and reduces costs associated with managing changes in local demand. In addition, these facilities do not face the variability issue associated with solar- and wind-powered generation. [15]

Federal and industry analyses consistently show that marginal wells dominate the population of active wells, often comprising 70–80% or more of producing wells, yet contributing only a small fraction, generally on the order of 10–20%, of total production volumes.[16] In Pennsylvania, for example, the vast majority of conventional wells fall into the marginal category, yet a small subset of high-producing unconventional wells accounts for the overwhelming share of total gas output,

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[13] RMI, *Grid-Scale Virtual Power Plants are Here. Have Utilities Noticed?* (May 14, 2026). Available at https://rmi.org/grid-scale-virtual-power-plants-are-here-have-utilities-noticed/.

[14] See, e.g., *Ohio River Valley Institute, Stayin' Alive: The Economic, Fiscal, Environmental and Climate Burdens of Pennsylvania's Hundreds of Thousands of Marginal Oil and Gas Wells* 3 (2021), https://ohiorivervalleyinstitute.org/stayin-alive/ (stating that "10 out of every 11 producing oil and gas wells in the region are low-producing stripper wells").

[15] U.S. Energy Info. Admin., Stripper Well Production Data.

[16] U.S. Envtl. Prot. Agency, *Marginal Conventional Wells* (noting that marginal wells make up the majority of U.S. wells but produce a relatively small share of total output); Nat'l Energy Tech. Lab., *Stripper Well Consortium* (describing marginal wells as a large share of well count with limited production contribution); see also Nat'l Stripper Well Ass'n, *Stripper Wells Overview*.

illustrating the stark divergence between well count and production contribution.[17] The persistence of stripper wells thus reflects not their volumetric dominance, but their role in extending the productive life of legacy reservoirs and maintaining supply from otherwise depleted fields.[18]

Distributed generation provides a viable solution to monetization. By co-locating small-scale natural gas generation with production sites, operators can utilize wells that might otherwise be abandoned. This approach converts a low-value or stranded commodity into electricity, which can be consumed on-site or delivered to the grid under interconnection arrangements with the utility. In doing so, combining the gas well with localized power generation creates a revenue stream without the need for traditional pipeline markets; and, because stripper wells operate on thin margins, even modest revenues can extend their productive life.

Conversely, the absence of such opportunities can accelerate well abandonment, reducing both domestic production and associated economic activity in rural regions. In many cases, abandonment occurs when declining production volumes, low commodity prices, increasing transportation costs, and other operating expenses combine to make continued operation uneconomic. The ability to deploy distributed generation in this context therefore has direct implications for resource utilization, local employment, and the preservation of existing energy infrastructure.

The consequences extend beyond economics. Abandoned and orphaned wells can create long-term environmental and public policy challenges, including methane emissions, groundwater contamination risks, land-use constraints, and significant plugging and remediation costs that may ultimately fall upon state governments and taxpayers.[19] By creating additional revenue opportunities that extend the productive life of marginal wells, distributed generation can help maintain active stewardship of existing assets, delay premature abandonment, and support broader efforts to manage Pennsylvania's legacy energy infrastructure responsibly.

Siting distributed generation at individual or aggregated stripper well sites could be a "win-win" solution for conventional producers and Pennsylvania's electric grid. To borrow an increasingly antiquated term, generation at stripper wells can be managed as "baseload" distributed generation.

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[17] FracTracker Alliance, *2021 Production from Pennsylvania's Oil and Gas Wells* (showing concentration of production in a small number of high-output wells, particularly unconventional wells).
[18] U.S. Energy Info. Admin., *Today in Energy* (July 2016) (noting that marginal wells produce a small share of total U.S. oil and gas output despite their large numbers).
[19] See Pennsylvania Department of Environmental Protection, *Legacy Well Plugging Program* (describing environmental and public safety risks associated with abandoned and orphaned wells, including methane emissions and groundwater impacts); Environmental & Energy Law Program, Harvard Law School, *Well Plugging: Federal and State Approaches to Addressing Orphaned and Abandoned Wells* (2025) (discussing environmental liabilities and remediation costs associated with orphaned wells).

As such, this generation complements the lower-energy costs of variable resources like solar to provide real electric system value. Moreover, the location of stripper wells means that the stripper well distributed generation can be sited as part of rural energy parks where grid costs are often quite high and can support economic development in those areas as well.

The U.S. Department of Energy has identified several drivers for adoption of Hybrid Energy Systems—systems that combine fossil, renewable, storage, and other distributed energy resources. These benefits include: cost and siting synergies, energy storage cost reductions, transmission benefits, market value, flexible commodity production, investment risk reduction, resilience, and environmental sustainability.[20]

III. Distributed Generation in a Grid Facing Rapid Growth in Data Center Demand

The increasing role of distributed generation reflects improvements in technologies and their integration into large-load energy strategies. Advances in high-efficiency reciprocating engines, microturbines, CHP systems, and digitally controlled hybrid generation platforms have expanded the scope of small-scale resources. These technologies now routinely support continuous, baseload-like operations, which allow distributed resources to function not merely as supplemental supply, but as primary energy sources.[21]

This technological evolution is occurring as reliability organizations and grid operators are warning that electricity demand growth is rapidly outpacing available supply and transmission infrastructure across large portions of the United States. In its 2025 Long-Term Reliability Assessment, NERC identified the PJM region, which includes Pennsylvania, as a "high risk" reliability area during the 2026–2030 planning horizon due to accelerating load growth, large-load interconnections, generation retirements, and insufficient firm resource additions. The assessment specifically identified large-load integration, including data centers and computational loads, as a growing reliability concern and concluded that "more resources are needed for demand growth.[22] Figure 1 below illustrates NERC's assessment of elevated and high-risk regions nationwide, including the PJM footprint.

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[20] U.S. Dep't of Energy, *Hybrid Energy Systems: Opportunities for Coordinated Research* (Apr. 2021), available at: https://www.sandia.gov/app/uploads/sites/256/2024/02/77503.pdf.

[21] See U.S. Dep't of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Its Expansion* 5–7 (2007) (describing advances in distributed generation technologies, including reciprocating engines and CHP systems).

[22] North American Electric Reliability Corporation, *2025 Long-Term Reliability Assessment* 2, 4 (Feb. 19, 2026) (identifying the RF-PJM region as a high-risk reliability area during the 2026–2030 planning horizon and identifying large-load integration and demand growth as emerging reliability concerns).

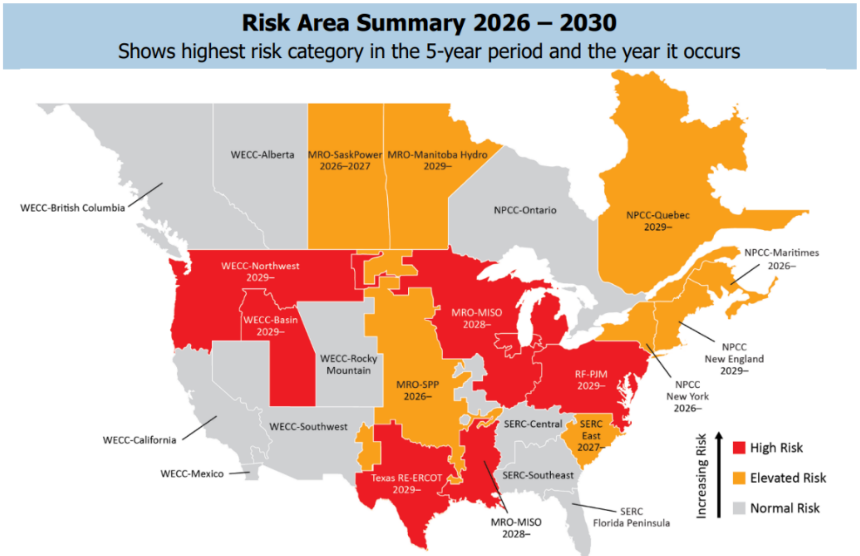

Figure 1. NERC 2025 LTRA RISK MAP.

NERC further projects that bulk power system summer peak demand growth is now forecast to be approximately 70% higher than projected in the prior year's assessment, driven in substantial part by data centers and other large-load facilities.[23] At the same time, NERC projects that approved and currently prospective generating resources may fail to keep pace with the scale and timing of anticipated demand growth, particularly during winter reliability periods.[24] These trends reinforce the growing importance of distributed and flexible generation resources capable of being deployed more rapidly and closer to load.

The anticipated significant electricity demand growth will require tens of gigawatts of new generation capacity by 2030.[25] AI data centers, as an example, operate at high load factors - drawing large amounts of power constantly every hour of the year - requiring firm, reliable power that often exceeds available transmission capacity.[26] In response, large-load customers are increasingly turning to distributed energy resources in behind-the-meter configurations, including

[23] *Id*. at 3 ("70% Higher Forecast Compared with 2024 LTRA").
[24] *Id*. at 3 (comparing projected 10-year demand growth against approved and prospective resource additions).
[25] See Eleftherios Iakovou et al., *Meeting Rising U.S. Electricity Demand from AI and Data Centers: An Integrated Technical and Policy Perspective* 1–2 (Mosbacher Inst. 2025) (projecting substantial load growth driven by data centers and AI infrastructure).
[26] See Rachel Mural et al., *AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment* 2 (Harv. Kennedy Sch. Belfer Ctr. 2026) (noting that data centers require continuous, high-load, reliable electricity supply).

natural gas–fired reciprocating engines, solar-plus-storage systems, and hybrid portfolios combining firm and variable resources.[27]

Importantly, many of these distributed configurations are beginning to replicate, at smaller scale, the operational characteristics historically associated with centralized utility generation, but with substantially greater locational flexibility and deployment speed. This is particularly relevant in Pennsylvania, where conventional natural gas and stripper wells remain geographically dispersed across large portions of the Commonwealth. While historically viewed primarily as upstream extraction assets, these wells increasingly present an opportunity to support distributed generation architectures capable of directly serving local industrial, manufacturing, and computational loads. In practical terms, this creates the potential for portions of Pennsylvania's existing conventional gas infrastructure to evolve from a purely commodity extraction network into a geographically distributed energy platform that supports manufacturing-scale load growth without requiring immediate large-scale transmission expansion.

In practice, DERs are being deployed in three distinct, but complementary, ways to support these large loads. First, they provide on-site primary generation, allowing facilities to bypass interconnection delays and transmission congestion while securing reliable power supply.[28] Second, DERs function as grid-supporting resources, reducing peak demand, smoothing load profiles, and supplying capacity during system stress events, which mitigates the need for immediate large-scale transmission and generation buildouts.[29] Infrastructure buildouts are charged to all customers through rates that distribute both utility capital costs and transmission service charge. Third, through aggregation and digital control platforms, distributed resources can operate as virtual power plants or flexible demand systems, responding to grid conditions and integrating with utility operations to improve overall system efficiency and reliability.[30]

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[27] See Iakovou et al., supra note 2, at 7 (describing deployment of behind-the-meter generation portfolios combining multiple technologies).
[28] *Id*. (explaining that behind-the-meter generation reduces reliance on transmission and avoids interconnection constraints).
[29] U.S. Dep't of Energy, *DOE Resources Available to Support Data Center Electricity Needs* 2 (2024) (identifying distributed resources and demand flexibility as tools to manage peak load and reliability).
[30] See Suedeen G. Kelly & J. Porter Wiseman, *Creating a Regulatory Framework for Demand-Side Investment in the Distribution Grid Equivalent to Capital Investment in Generation* 3–5 (Akin Gump 2016) (describing aggregation and dispatch of distributed resources through advanced control systems); U.S. Dep't of Energy, *Virtual Power Plants: Projects and Programs* (2024), https://www.energy.gov/edf/virtual-power-plants-projects (describing deployment of aggregated DER systems to provide grid services and support system reliability); Fed. Energy Regul. Comm'n, Order No. 2222: *Facilitating Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators* (2020) (enabling aggregated DERs to participate in wholesale electricity markets); Sid Suryanarayanan et al., *Harnessing Virtual Power Plants Reliably: Enabling Tools for Increased Observability, Controllability, Operation, and Aggregation of*

Data center operators are increasingly entering into direct power purchase agreements, co-locating generation with load, and deploying multi-technology portfolios containing DERs in an effort to reduce exposure to wholesale price volatility and grid constraints while maintaining operational continuity.[31] In some cases, firms are installing multiple on-site natural gas–fired generators to meet immediate load requirements where grid supply cannot be delivered in time.[32] At the same time, distributed systems are being integrated into broader grid strategies to help accommodate the rapid influx of large loads without compromising reliability or imposing disproportionate infrastructure costs on the system.[33] Taken together, these developments demonstrate that distributed generation is no longer a niche resource, but rather a structural component of modern grid architecture capable of both directly serving large, high-density loads and providing system-wide benefits that offset reliability challenges associated with rapid load growth.

As utilities and regional transmission organizations confront increasingly constrained interconnection queues, rising reserve margin concerns, and accelerating demand forecasts, distributed generation offers an important complementary pathway for expanding available supply. Unlike large, centralized generation and transmission projects, which frequently require multi-year siting, permitting, and construction timelines, distributed resources can often be deployed incrementally and closer to the point of consumption. In regions facing reliability stress, this flexibility may become increasingly important to maintaining system adequacy while broader transmission and generation infrastructure expansions continue to develop.

These developments underscore the need to evaluate distributed generation within the broader context of system conditions and policy design. Distributed resources are not a substitute for centralized infrastructure, but a complementary component of a diversified energy system. Their continued deployment depends on regulatory frameworks that recognize both their costs and their system value. Utilities and grid overseers that fail to take advantage of these benefits condemn all grid customers to unnecessary service costs and threaten the potential for economic growth in the Commonwealth.

Further, distributed generation has become established as a critical component of the modern electric system, both in terms of scale and operational function. The remaining question is not whether these resources contribute to system reliability and supply, but whether existing

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Distributed Energy Resources 1–2 (2024) (explaining that DER aggregation into virtual power plants can provide resource adequacy, reduce congestion, and support grid reliability).

[31] See Mural et al., supra note 3, at 3 (discussing use of power purchase agreements and co-located generation for data centers).

[32] *Id*. at 2 (noting installation of on-site natural gas generation to meet immediate load demand).

[33] U.S. Dep't of Energy, supra note 6, at 8 (discussing integration of distributed resources into grid operations and planning).

compensation structures support their continued development by reflecting this added value. And because customer-generation is financed through private capital and must recover its costs through market or tariff-based revenues, this question can be evaluated directly through project economics. The analysis that follows examines those economics in detail, using a levelized cost framework to assess whether current compensation mechanisms support, or limit, continued investment in distributed generation.

IV. Customer-Generators as Private Investment in Pennsylvania's Energy Economy

Customer-generation in Pennsylvania is best understood as a market structure established by statute and not as a single technological category. Under the AEPS Act, a "customer-generator" includes a range of technologies capable of producing electricity for on-site use and grid interaction, including systems utilizing natural gas, biologically derived methane, and other qualifying fuels.[34]

This statutory framework reflects a deliberate policy choice to allow private investment to participate in electric generation. That choice has resulted in a growing base of customer-generators across the Commonwealth, including projects that rely upon conventional and stripper well production as the underlying fuel source for distributed electricity generation, similar to the role that solar and wind resources play in renewable distributed generation systems.

Customer-generation is a mechanism that allows private investors to commit capital and assume risks that ratepayers will not have to shoulder. In this way, private investors have the same investment-backed expectations as utility investors. Properly understood, the customer-generator framework reflects a familiar principle: when individuals and businesses are permitted to deploy their own resources to produce electricity and transact with the grid under stable, transparent rules, the result is additional supply and a more resilient system.

That principle is especially relevant today. Pennsylvania is entering a period of structural load growth driven by data centers, advanced manufacturing, and electrification across multiple sectors. Meeting that demand will require not only utility-scale investment, but also distributed generation that is privately financed and can be deployed more quickly and flexibly. Just the *expectation* of serving this demand has dramatically increased capacity auction prices—from about $28 per MW-day in 2024/2025 to about $333 per MW in 2026 and 2027. Customer-generators represent one of the few solutions to encourage new supply without requiring ratepayer-funded infrastructure expansion.

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[34] See 73 Pa. Stat. § 1648.2 (definition of "customer-generator" under AEPS).

A. Customer-Generation as a Capital-Intensive, Private Market Activity

Customer-generation projects in Pennsylvania are fundamentally a private investment model that require substantial upfront private investment and ongoing operational commitments. These upfront investments include finance, site preparation, interconnection upgrades, engineering, equipment procurement, construction, and long-term operations and maintenance. These are not hypothetical or marginal costs; they represent real capital injected into Pennsylvania's economy, often at the project level and without guarantees of recovery absent a stable compensation structure.[35]

Unlike utility infrastructure investments, which are typically supported through highly regulated cost-recovery frameworks and default service procurement structures, customer-generators bear the upfront capital risk directly and must evaluate whether a project is economically viable before any investment is made. The customer-generator assumes the risks associated with fuel supply, system performance, interconnection costs, regulatory changes, and long-term revenue sufficiency, as well as insurance, operations and maintenance, and mechanical failure. If those risks are misjudged, the loss is borne by the customer-generator and not by ratepayers. In that respect, customer-generation reflects a market-driven investment decision, not regulated market spending.[36]

Pennsylvania's statutory framework has long recognized this structure. The AEPS Act was designed to encourage investment in a range of alternative energy resources and to foster economic development by creating a market for qualifying generation technologies.[37] The AEPS does not treat all resources equally. It establishes a tiered compliance structure, including Tier I and Tier II resource categories that expressly recognize multiple resource types, including distributed generation systems and certain non-solar technologies, as eligible participants within the broader alternative energy framework.[38] The customer-generator construct operates within this statutory structure and allows qualifying distributed generation projects, including those associated with existing natural gas production, to interconnect and transact under standardized net metering and interconnection rules.

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[35] See U.S. Dep't of Energy, *The Potential Benefits of Distributed Generation and the Rate-Related Issues that May Impede Its Expansion* (2007) (describing distributed generation projects as capital-intensive investments requiring site-specific development, interconnection, and operational expenditures).

[36] See *id.*; see also 73 Pa. Stat. § 1648.5 (establishing customer-generator framework without guaranteed cost recovery mechanisms typical of regulated utilities).

[37] Alternative Energy Portfolio Standards Act, Act of Nov. 30, 2004, P.L. 1672, No. 213, 73 Pa. Stat. §§ 1648.1–1648.8.

[38] *Id*. § 1648.2

According to the Pennsylvania Public Utility Commission's ("PA PUC") most recent Net Metering and Interconnection Report, as of May 31, 2025, Pennsylvania had 87,980 interconnected customer-generators with 1,187 MW of aggregate nameplate capacity, up from 59,663 systems and 803 MW in 2023.[39] In just two years, the Commonwealth added more than 28,000 customer-generators and approximately 384 MW of capacity, reflecting a sustained increase in distributed generation.[40]

That market growth is evidence of capital formation at scale. Each interconnection represents a discrete investment decision involving engineering, equipment, construction, and interconnection expenditures. Taken together, these projects constitute a distributed portfolio of generation assets deployed across the Commonwealth. The economic implications of such investment are well established. Pennsylvania-specific economic modeling demonstrates that energy project development drives direct, indirect, and induced economic activity, including capital expenditures, job creation, and increases in gross state product, as project spending flows through local labor, engineering, permitting, and construction sectors.[41]

For example, independent analysis of energy development in Pennsylvania estimates that expanded generation deployment can support approximately $13.1 billion in capital investment, $11.4 billion in gross state product (GSP) value added, and more than 129,000 job-years associated with construction and operation from 2024 through 2031.[42] These impacts are not limited to any single technology; they reflect the broader economic effect of private capital investment in distributed and grid-connected generation assets.

The underlying cost structure of these projects explains those economic effects. As shown in the Table 1, a significant portion of project expenditures, particularly those related to engineering, permitting, installation labor, electrical work, and balance-of-system components, are locally sourced, even where certain equipment components are procured outside the state.[43] This means that customer-generation projects produce tangible in-state economic benefits at the project level, including local employment, contractor activity, and tax base contributions.

Table 1. Illustrative Generation Project Cost Components ($/Watt, 2021$)
(Adapted from Gabel Associates; NREL cost structure)

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[39] Pa. Pub. Util. Comm'n, *Net Metering and Interconnection Report 2023–2025* (2025), https://www.puc.pa.gov
[40] *Id*.
[41] See Gabel Assocs., Inc., *Economic and Environmental Impact of Governor Shapiro's "30 x 30" Alternative Energy Pledge 10* (Feb. 2024) (describing direct, indirect, and induced economic impacts of energy project development).
[42] *Id*. at 6, 12 (estimating $13.1 billion in capital investment, $11.4 billion in GSP value added, and 129,134 job-years).
[43] *Id*. at 10 (noting locally sourced installation labor and project cost components).

Cost Category	Residential	Commercial	Grid-Scale	Primary Economic Impact Location
EPC / Developer Profit	$0.34	$0.14	$0.05	Local / Regional
Developer Overhead	$0.26	$0.40	$0.02	Local / Regional
EPC Overhead	$0.40	$0.12	$0.06	Local / Regional
Permitting	$0.21	$0.04	$0.02	Local (PA-based)
Sales Tax	$0.08	$0.06	$0.04	Local (PA-based)
Install Labor & Equipment	$0.16	$0.16	$0.12	Local (PA-based labor)
Electrical BOS	$0.37	$0.28	$0.08	Local / Regional contractors
Structural BOS	$0.16	$0.17	$0.18	Local / Regional contractors
Contingency	—	$0.05	$0.03	Mixed
Transmission (if any)	—	—	$0.01	Regional
Inverter	$0.44	$0.06	$0.03	Largely external manufacturing
Module / Equipment Core	$0.53	$0.46	$0.35	Largely external manufacturing
Total ($/W)	$2.95	$1.94	$0.99	

Source: Gabel Associates, Economic and Environmental Impact of Governor Shapiro's "30 x 30" Alternative Energy Pledge, at 10 (2024) (citing NREL cost data).

For non-solar customer-generators, particularly those utilizing natural gas from existing or legacy well infrastructure, the economic model is distinct but fully consistent with this framework. These projects are typically located at or near existing well sites or industrial operations, operate at continuous, steady output, and rely on on-site or proximate fuel supply rather than external resource variability.[44] Federal research has identified distributed generation as a viable pathway to convert otherwise constrained or underutilized gas streams into productive electricity, improving project economics and reducing waste.[45]

In these cases, customer-generation is not simply a method of producing electricity; it is a means of optimizing existing energy assets through private capital deployment. The same economic principle applies across all customer-generators: projects are developed only where expected

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[44] See U.S. Energy Info. Admin., *Stripper Wells Account for Significant Share of U.S. Oil Production* (2016), https://www.eia.gov/todayinenergy/detail.php?id=26872

[45] See U.S. Dep't of Energy, *Nat'l Energy Tech. Lab., Associated Gas Utilization via Distributed Generation*, https://www.netl.doe.gov/node/3910

revenues are sufficient to justify the upfront investment and ongoing risk. Where that condition is not met, projects do not move forward.

This is the defining feature of the customer-generator model. It is a system in which private capital is deployed at risk to produce generation capacity, and where the continued growth of that capacity depends on maintaining a framework that allows those investments to remain economically viable.

B. Customer-Generators and the Productive Use of Existing Energy Assets

For many Pennsylvania stakeholders, especially independent oil and natural gas operators, customer-generation is not simply a new line of business, but rather it has become a mechanism for sustaining and optimizing the value of existing energy assets that would otherwise face declining economic viability. This is especially true for low-volume stripper wells. These wells represent a significant component of domestic energy supply and are at persistent risk of being shut in due to unfavorable economics.[46] As conventional production declines while demand for natural gas remains structurally significant, the continued utilization of these marginal resources depends on the availability of economic pathways to extend their productive life.

Customer-generation under the AEPS Act provides such a pathway. Distributed generation technologies allow operators to convert produced gas into electricity at or near the point of extraction, bypassing the need for costly midstream infrastructure, compression, or pipeline interconnections. In doing so, these systems use gas streams that may otherwise be constrained, expensive to transport, or subject to flaring or curtailment. The U.S. Department of Energy's Section 1817 study identifies distributed generation as providing a range of quantifiable system and economic benefits, including reductions in peak demand, improved reliability, the ability to supply emergency and on-site power, and the deferral or avoidance of utility investments in generation, transmission, and distribution infrastructure.[47] These findings reflect the economic value of locating generation at or near the point of use, where it can displace grid-supplied energy and reduce the need for additional infrastructure investment. In this way, distributed generation does not simply produce electricity; it alters the economic profile of the underlying fuel resource by expanding the range of commercially viable uses.

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[46] *Id*. (describing stripper wells as "under constant threat of permanent loss (shut-in) due to marginal economics").

[47] U.S. Dep't of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Its Expansion* 14–21 (2007) (identifying benefits including reduced peak demand, improved reliability, emergency supply capability, and deferral of generation, transmission, and distribution investment).

Table 2. System and Economic Benefits of Distributed Generation (DOE §1817 Study)
(Adapted for application to customer-generation using existing gas resources)

Category of Benefit	Description (DOE Findings)	Relevance to Stripper Well Customer-Generators
Peak Load Reduction	On-site generation reduces demand on the grid during peak periods	Reduces need for external power purchases; increases value of on-site generation
Deferred Infrastructure Investment	DG can offset or delay investment in generation, transmission, and distribution facilities	Avoids need for pipeline expansion or grid upgrades tied to centralized supply
Reliability and Resilience	Provides emergency and backup power; enhances system reliability	Enables continuous operation and monetization of gas independent of grid conditions
Power Quality Improvements	Improves voltage support and reduces disturbances	Supports stable, continuous on-site operations
Transmission & Distribution Loss Reduction	Generation near load reduces line losses	Eliminates losses associated with transporting gas or electricity over long distances
Ancillary Services Capability	Can provide reactive power and other grid support services	Potential future value streams as markets evolve
Reduced Land Use / Infrastructure Footprint	Less need for new large-scale infrastructure and rights-of-way	Maximizes use of existing well sites and infrastructure
Security / Resilience Benefits	Reduces vulnerability to centralized system disruptions	Allows wells to operate and produce value even during grid instability

Source: U.S. Dep't of Energy, The Potential Benefits of Distributed Generation (2007).

Where gas sales revenues are insufficient to cover those overhead costs, even a modest additional income from electric generation can determine whether a well remains operational or abandoned. In this respect, customer-generation functions as a value-stabilizing mechanism, effectively raising the economic threshold at which continued production remains feasible.

This dynamic is consistent with broader findings regarding distributed generation. The U.S. Department of Energy concluded that on-site generation can reduce peak demand, defer investment in transmission and distribution infrastructure, and improve overall system efficiency by locating generation closer to load.[48] By reducing transportation losses and avoiding certain infrastructure costs, distributed generation enhances the economic value of the underlying fuel resource. These benefits are particularly pronounced in cases where generation is co-located with existing fossil fuel assets, allowing operators to leverage established infrastructure and fuel supply without incurring the full costs associated with centralized generation models.

At the system level, the productive use of existing energy assets through customer-generation is relevant not only to project economics, but also to grid reliability and resilience. The U.S. Department of Energy's Section 1817 study identified several categories of benefits associated with distributed generation, including increased electric system reliability, emergency supply capability, reductions in peak power requirements through on-site generation, and offsets to investment in generation, transmission, and distribution facilities.[49] In this way, customer-investors in distributed generation can lower consumer electric bills for all customers—especially by reducing wholesale market costs and transmission service charges. Those findings are consistent with more recent transmission-and-distribution research. In a detailed MIT analysis of distributed energy resources on electricity networks, Michael E. Birk determined that DERs located near load were found to reduce reliance on distant generation, mitigate congestion and losses, and affect locational prices and system operations, particularly in constrained areas.[50] In the New York case study modeled by Birk in his MIT analysis, transmission and distribution losses accounted for roughly 0% to 8% of locational marginal prices, while the congestion component ranged from 1% to more than 30% in the most constrained zones.[51] In practical terms, where generation is located closer to load, the system can avoid at least some of the costs associated with moving power over long distances and managing congestion at stressed interfaces.

Several recent studies quantify the economic benefits of a strong distributed energy resources strategy. In Virginia, a study for Solar United Neighbors revealed more than $600 million in savings from increased deployment of distributed energy resources—more than twice the costs, even with incentives.[52] A study by Synapse for New York found average savings in excess of $1

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[48] *Id*., at 14-21 (finding distributed generation can reduce peak demand, defer infrastructure investment, and improve system efficiency).

[49] U.S. Dep't of Energy, The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Its Expansion 14–21 (2007)

[50] Michael E. Birk, *Impact of Distributed Energy Resources on Locational Marginal Prices and Electricity Networks* 3, 7–8, 30–35 (M.S. thesis, Massachusetts Institute of Technology 2016) (finding DERs affect prices, grid operations, reliability, congestion, and losses, and discussing the value of resources located near load).

[51] *Id.* at 30–33 (reporting that transmission and distribution losses accounted for approximately 0% to 8% of LMPs and congestion ranged from 1% to over 30% in the most constrained zones).

[52] Solar United Neighbors, *Distributed Energy Resources in Virginia: A Path to Lower Electric Bills and a Stronger Grid* (Apr. 2026), available at: https://solarunitedneighbors.org/resources/report-value-of-ders-in-virginia/

billion by 2035 from distributed energy resources, or between $87 and $46 in annual residential savings per year (depending on the region).[53] Likewise, a study by the Texas Advanced Business Alliance found that distributed energy resources could save $1.153 billion per year over the next ten years on transmission and distribution spending.[54] The benefits and savings would be comparable or greater with generation from continuously-producing stripper well generators, especially as distributed storage assets are added to these sites and benefits are realized.

These attributes and potential savings from distributed resources are increasingly relevant in the PJM region and in Pennsylvania specifically. PJM's 2026 Load Forecast projects that summer peak load will increase to approximately 222,106 MW by 2036, representing a 10-year increase of 65,733 MW, with an average annual growth rate of 3.6% over the next decade.[55] Winter peak demand is projected to grow at a comparable pace, reaching 204,650 MW by 2035/2036, while total net energy demand is expected to increase by more than 581,000 GWh over the same ten-year period.[56] These projections reflect sustained structural growth in electricity demand across the PJM footprint, driven by a combination of electrification, economic expansion, and large-load additions.

At the same time, Pennsylvania's infrastructure profile reflects the broader challenge of an aging and increasingly strained energy system. The American Society of Civil Engineers' 2022 Pennsylvania Infrastructure Report Card assigned the Commonwealth an overall grade of C-, noting that Pennsylvania has "some of the oldest infrastructure in the country" and faces substantial maintenance backlogs across multiple sectors, including energy and electric distribution systems.[57] In the energy sector specifically, the report identifies growing reliability concerns at the distribution level, where localized outages have nearly tripled over the past 25 years, even as the broader PJM system maintains a reserve margin exceeding 30 percent.[58] These conditions reflect a system that, while historically robust at the generation level, is increasingly constrained at the point of delivery.

Pennsylvania's energy profile further underscores this dynamic. The Commonwealth remains one of the largest net exporters of electricity in the United States and maintains a diverse generation

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[53] Synapse Energy Economics, *Sunlight and Storage into Savings* (Jan. 2026), available at: https://drive.google.com/file/d/1_7B7gHlzZ7QlEewtJ-X_QfRQtDyNvf-J/view.
[54] Texas Advanced Business Energy Alliance, *The Value of Integrating Distributed Energy Resources in Texas* (2026), available at: https://texasadvancedenergy.org.
[55] PJM Interconnection, *2026 Load Forecast Report* 6 (Jan. 14, 2026) (projecting summer peak load of 222,106 MW by 2036, a 10-year increase of 65,733 MW, with average annual growth of 3.6%, and significant increases in winter peak and net energy demand).
[56] *Id*.
[57] Am. Soc'y of Civ. Eng'rs, 2022 *Pennsylvania Infrastructure Report Card* (assigning Pennsylvania an overall infrastructure grade of C-).
[58] *Id*. at 43 (noting reliability concerns and increase in localized outages despite regional capacity margins).

portfolio dominated by natural gas, which accounted for approximately 52% of total net electricity generation as of 2020, compared to just 15% in 2010, while coal declined from 48% to approximately 10% over the same period.[59] Nuclear energy continues to represent a significant share of generation, while non-hydroelectric renewables, including distributed resources, remain a comparatively smaller but growing component of total capacity.[60] This shift toward natural gas–dominated generation has increased reliance on both gas production infrastructure and electric transmission and distribution networks, placing additional stress on systems that were largely designed decades earlier for different load patterns and generation profiles.

Within this context, DERs are increasingly recognized as a mechanism to enhance system performance at the margins. The ASCE report specifically identifies DERs as a "key component to grid reliability and flexibility," noting that they enable energy production closer to the point of consumption and can reduce system costs through avoided transmission and distribution investments.[61] By reducing dependence on long-distance delivery and supplementing local supply, distributed generation resources can mitigate some of the operational pressures associated with aging infrastructure and geographically concentrated load growth.

In Pennsylvania, these attributes are even more relevant, considering much of the Commonwealth's transmission and distribution infrastructure dates back to the 1950s and 1960s, with some originating as early as the 1920s. Much of this legacy infrastructure requires ongoing, ratepayer-funded, upgrades to accommodate new generation sources and evolving load characteristics, in addition to maintaining and improving on reliability.[62] In that environment, distributed customer-generation, especially, when located at or near existing energy production sites, can provide localized supply that supports host load, reduces reliance on constrained transmission paths, and contributes capacity without requiring the long lead times associated with large-scale infrastructure expansion.

Another key economic and operational benefit of distributed generation is that owners of these facilities pay for all the grid infrastructure costs needed to safely and reliably interconnect them to the grid. Customer-generators don't just bring generation to the grid, they improve the grid, including making the grid ready for deployment of additional distributed resources like distributed storage.

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[59] *Id*. at 43–44 (reporting shift in generation mix from coal to natural gas between 2010 and 2020).
[60] *Id*. at 44 (describing contribution of nuclear and growth of renewable resources).
[61] *Id*. at 49 (identifying distributed energy resources as enhancing reliability, flexibility, and reducing system costs through avoided infrastructure investment).
[62] *Id*. at 46 (noting that much of Pennsylvania's transmission and distribution infrastructure dates to the mid-20th century or earlier).

Recent operational analysis shows that distributed energy resources are already material to grid operations. ERCOT, the grid operator for most of Texas' load, reported in August 2025 that DER capacity on the Texas grid had reached approximately 6,050 MW as of December 31, 2024, up from 650 MW in 2015, with rooftop solar alone accounting for about 3,110 MW in 2024.[63] ERCOT further found that DERs can support reliability by reducing peak demand during shortages and emergencies, providing ancillary services such as frequency regulation and voltage support, strengthening resilience during extreme weather, supporting demand response, and reducing transmission and distribution costs because energy is produced closer to where it is consumed.[64] ERCOT also concluded that DERs are increasingly being used as load-modifying resources for both distribution non-wires alternatives and wholesale capacity and ancillary services, and warned that insufficient operational visibility into DERs can impair load forecasting, state estimation, contingency analysis, and voltage management as penetration grows.

Customer-generators that optimize legacy oil and gas infrastructure reflect a broader shift in how existing energy assets are evaluated. Rather than viewing these assets as declining or stranded resources, emerging research recognizes their role in a diversified energy system that incorporates both conventional and distributed generation. Advances in distributed energy technologies have expanded the range of applications through which existing fuel resources can be utilized efficiently and economically.

Conventional thinking about the grid and resource options available to support it is grounded on conventional modeling tools developed in decades past, when the economics of plant and infrastructure scale still dominated the industry. These models, largely still in use today, cannot dynamically model distributed resources in production cost and capacity expansion modeling, so they do not appear as selectable resources in utility planning exercises. But refinements to analytical modeling tools and entirely new tools that borrow from super-computing experience reveal a valuable synergy between utility-scale and distributed resources. A set of studies conducted using the WIS:dom-P® model developed by Clean Vibrant Energy took advantage of system models adapted from those used to model the complexities of weather.[65] These studies not only looked at the entire grid of the continental U.S., but also evaluated distributed generation and storage down to a 1 square kilometer/5 second/1 kilowatt resolution. The resulting findings were

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[63] Elec. Reliability Council of Tex., Inc., *Distributed Energy Resources Operational Data: Value, Insights, and Technology Pathways for a Reliable Grid,* 3 (Aug. 2025) (reporting that DERs in the ERCOT region totaled approximately 6,050 MW as of Dec. 31, 2024, up from 650 MW in 2015, and that rooftop solar accounted for approximately 3,110 MW in 2024).

[64] *Id*. at 6–8 (stating that DERs can support peak shaving during shortages and emergencies, provide ancillary services including frequency regulation and voltage support, improve resilience during extreme weather, support demand response, and reduce transmission and distribution costs when generation is located closer to consumption).

[65] Vibrant Clean Energy, *The WIS:dom® Planning Model,* available at: https://vibrantcleanenergy.com/products/wisdom-p/.

that huge grid cost savings were possible when distributed resources were coordinated and optimized—almost one-half trillion dollars in savings by 2050 for the grid alone, and three times as much if electrified buildings and transportation are added to the scope of the study. And when the two-way carrying capacity if the grid is also harnessed to orchestrate the mix of utility- and distributed-scale resources, the savings appear not just during peak hours, but over 84% of the hours in the year.[66]

For conventional natural gas operators, this evolution has practical consequences. Customer-generation allows these operators to integrate electricity production directly into their existing operations, creating a vertically aligned model in which fuel production and energy generation occur within a single system. The results of having gas generation at both the top and bottom of the system are more efficient use of resources, reduced exposure to midstream constraints, and an additional revenue stream that supports continued operation. Stated simply, these are the benefits that come from the option of shipping gas through pipelines *or* through wires as electrons.

C. Modeling Economic Viability for Stripper Well Distributed Generation

The same principle that governs all customer-generation applies here: projects proceed only where the expected value of electricity production justifies the capital investment and operational risk. Where that condition is satisfied, customer-generation enables the continued productive use of assets that might otherwise be retired. Where it is not, those assets remain uneconomic and are ultimately removed from the system.

To assess whether customer-generation projects are economically cost-effective under different compensation structures, it is necessary to begin with a transparent set of assumptions and a replicable analytical framework. The analysis presented here is intentionally conservative and is designed to isolate one component of project economics—capital recovery—before layering in the additional costs that ultimately determine full project feasibility.

For purposes of this analysis, the project economics are modeled using a 2.5 MW natural-gas-fired distributed generation unit. The project assumes a 10-year recovery period, producing a capital recovery factor of 0.1627 before tax incentives. On that basis, capital recovery equals approximately 2.903 cents/kWh. After applying a 40% investment tax credit, the effective capital recovery factor declines to approximately 0.0976, reducing the capital-recovery component to approximately 1.74 cents/kWh.

[66] Local Solar for All, *Local Solar Roadmap* (Dec. 2020), available at: https://www.localsolarforall.org/roadmap.

The project's operating cost, excluding fuel, is approximately 2.0 cents/kWh. Fuel cost depends directly on natural gas price and generator efficiency. At 43% efficiency, natural gas priced at \$4.00/MMBtu produces an estimated fuel cost of approximately 3.17 cents/kWh. At the project's trailing 12-month natural gas price of \$2.658/MMBtu, fuel cost declines to approximately 2.15 cents/kWh.

Accordingly, using the project's actual 12-month gas price, the all-in cost stack is approximately:

- Capital recovery after ITC: 1.74 cents/kWh
- Non-fuel operating cost: 2.0 cents/kWh
- Fuel cost: 2.5 cents/kWh
- Total estimated cost: 6.24 cents/kWh

At \$4.00/MMBtu gas, the total estimated cost rises to approximately 7.53 cents/kWh. At gas prices above approximately \$5.00/MMBtu, the operator may rationally elect to curtail generation and instead sell the gas into the pipeline, illustrating that distributed natural-gas generation is sensitive not only to electric compensation levels, but also to the opportunity cost of the underlying fuel supply.

Under these assumptions, the annualized capital requirement is calculated using a standard capital recovery factor:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where *i* represents the required return on capital and *n* represents the project recovery period. For the illustrative 2.5 MW natural-gas-fired distributed generation project modeled here, the analysis assumes a 10-year recovery period and produces a capital recovery factor of approximately 0.1627 before application of available tax incentives. After applying the project's assumed 40% investment tax credit, the effective capital recovery factor declines to approximately 0.0976. This factor is then applied to the project's installed capital investment using the standard relationship:

$$A = P(CRF)$$

where:

- P= total installed project cost
- A= required annual capital recovery revenue

This step converts the upfront capital cost into an annualized revenue requirement that must be recovered each year over the life of the project.

The project assumes an 85% capacity factor, producing annual generation of:

$$2{,}500kW\ x\ \ 8{,}760\frac{hours}{year}\ x\ 85\% = 18{,}615{,}000\ kWh/year$$

The capital-recovery-only break-even price is therefore calculated as:

$$\text{Break-even price} = \frac{\text{Annual capital recovery requirement}}{\text{Annual kWh output}}$$

Unlike variable generation resources, however, conventional natural-gas-fired distributed generation projects must also account for ongoing operational and fuel costs, which represent a substantial portion of the total revenue requirement. The modeled project's non-fuel operating cost is approximately 2.0 cents/kWh. Fuel costs vary directly with natural gas pricing and generator efficiency.

Applying this framework to the modeled 2.5 MW distributed natural gas generation project yields the following illustrative results:

Table 3. Modeled 2.5 MW distributed natural gas generation project yields

Illustrative Scenario	Capital Recovery (cents/kWh)	Non-Fuel O&M (cents/kWh)	Fuel Cost (cents/kWh)	Total Estimated Revenue Requirement
Capital Recovery Only (before ITC)	2.903	—	—	2.903 cents/kWh
Capital Recovery Only (after 40% ITC)	1.740	—	—	1.740 cents/kWh
Full Project Cost at $2.658/MMBtu Gas	1.740	2.000	2.500	6.240 cents/kWh
Full Project Cost at $4.00/MMBtu Gas	1.740	2.000	3.790	7.530 cents/kWh

These figures demonstrate that capital recovery alone represents only one component of overall project economics. Even after application of available federal tax incentives, fuel and operating costs increase the total revenue requirement and create sensitivity to commodity natural gas prices. The project therefore requires compensation levels sufficient to not only recover capital investment, but also sustain ongoing operations under varying fuel market conditions.

That baseline must be interpreted carefully. Although the modeled 2.5 MW distributed natural gas generation project produces a post-tax-incentive capital recovery requirement of approximately 1.74 cents/kWh, that figure excludes ongoing and project-specific operating costs, including fixed and variable operations and maintenance, engine overhaul reserves, fuel conditioning, emissions compliance, insurance, tax obligations, opportunity cost of capital, and the risk-adjusted return required by investors. When those elements are incorporated, the all-in revenue requirement for a conventional gas-based customer-generator is necessarily higher.[67] Using the project assumptions modeled here, total estimated operating costs increase to approximately 6.24 cents/kWh at a trailing 12-month natural gas price of $2.658/MMBtu and approximately 7.53 cents/kWh at a $4.00/MMBtu gas price.

Against that baseline, the relevant policy question becomes whether prevailing or proposed compensation structures provide sufficient revenue not only to recover capital, but also to sustain ongoing operations and justify continued private investment.

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[67] See U.S. Dep't of Energy, The Potential Benefits of Distributed Generation (2007) (identifying capital and operating cost components of distributed generation projects).

The FirstEnergy Pennsylvania Electric Company's ("FirstEnergy") Default Service Plan filing provides a concrete benchmark for evaluating that question. For the December 1, 2025, through May 31, 2026, period, the filing reports a residential Price-to-Compare ("PTC") rate of \$0.10947/kWh and a commercial PTC rate of \$0.10993/kWh. It also reports current cost components reflecting avoided wholesale procurement costs of \$0.09103/kWh for residential service and \$0.08717/kWh for commercial service, as well as loss-adjusted current cost components of \$0.09932/kWh and \$0.09500/kWh, respectively.[68] Because distributed generation produces electricity at or near the point of consumption, the loss-adjusted values provide a particularly relevant comparison by reflecting the energy value delivered after accounting for transmission and distribution losses that would otherwise occur on the electric system.[69]

To illustrate the practical effect of these differences, consider the modeled 2.5 MW customer-generation project operating at a 50% capacity factor, consistent with the operating profile and dispatch assumptions used throughout this analysis. At that utilization level, the facility produces approximately 10,950,000 kWh annually (2,500 kW × 8,760 hours × 50%). At the residential PTC rate, that output yields annual gross revenue of approximately \$1,198,696.50, while the commercial PTC rate yields approximately \$1,203,733.50. By contrast, compensation at the utility's current wholesale avoided cost component yields approximately \$996,778.50 under the residential benchmark and \$954,511.50 under the commercial benchmark. Compensation at the loss-adjusted current cost component yields approximately \$1,087,554.00 and \$1,040,250.00, respectively.

Using the modeled project economics discussed above, these compensation levels exceed the estimated all-in operating cost range of approximately 6.24 to 7.53 cents/kWh under the modeled fuel-price scenarios. However, the resulting margin is narrower under avoided-cost-based compensation structures than under full retail or loss-adjusted compensation structures, particularly during periods of elevated natural gas prices or reduced operating efficiency. At the modeled 43% utilization level, this distinction becomes increasingly important because project economics are substantially more sensitive to fluctuations in fuel prices and operating costs than under higher utilization assumptions. This distinction is economically significant because customer-generators must absorb commodity risk, operational risk, and capital recovery

[68] Petition of FirstEnergy Pennsylvania Electric Company for Approval of Its Default Service Program for the Period June 1, 2027 Through May 31, 2031, FE PA Ex. CDL-1, at 2 (filed Feb. 3, 2026) (defining the PTC formula, current cost component, and West Penn loss factors of 1.0910 and 1.0899).

[69] The cited rates are representative residential and commercial default-service rates reported by FirstEnergy for the applicable six-month period and are presented as illustrative benchmarks. Industrial customers are served under separate hourly pricing mechanisms rather than the Price-to-Compare structure.

obligations directly, without the benefit of regulated cost recovery mechanisms available to traditional utility infrastructure investments.

Table 4. Annual Revenue Comparison (2.5 MW Project at 50% Capacity Factor)

Compensation Benchmark	Rate ($/kWh)	Annual Output (kWh)	Annual Revenue ($)
Residential PTC	0.10947	10,950,000	$1,198,696.50
Commercial PTC	0.10993	10,950,000	$1,203,733.50
Residential Current Cost	0.09103	10,950,000	$996,778.50
Commercial Current Cost	0.08717	10,950,000	$954,511.50
Residential Loss-Adjusted Cost	0.09932	10,950,000	$1,087,554.00
Commercial Loss-Adjusted Cost	0.09500	10,950,000	$1,040,250.00

Source: FirstEnergy Pa. Elec. Co., West Penn Rate Dist., *Estimated Price-to-Compare Sample Calculations* (Dec. 1, 2025 to May 31, 2026)

Using the modeled 2.5 MW project operating at a 50% capacity factor, moving from the PTC benchmark to the current wholesale cost component reduces annual revenue by approximately $201,918 under the residential benchmark and approximately $249,222 under the commercial benchmark. Even when compared to loss-adjusted current cost values, the reduction remains significant; approximately $111,142 and $163,484, respectively.

These revenue differentials occur before accounting for any of the operating costs described above. As a result, they directly affect whether a project can cover its full cost structure and achieve an acceptable return. Where compensation levels are reduced below the level necessary to recover both fixed and recurring operating costs, investment incentives deteriorate, project deployment slows, and existing distributed generation assets become increasingly vulnerable to retirement or curtailment.

A more complete way to evaluate project feasibility is to use a levelized cost of energy framework. Under that approach, the required compensation rate is not limited to annualized capital recovery. It is the sum of four components: (1) annualized installed cost, (2) fixed operating and maintenance expense, (3) variable operating expense and compliance costs, and (4) fuel cost or fuel opportunity cost, each expressed on a per-kilowatt-hour basis. That framework is particularly appropriate for conventional gas-based customer-generation because these projects are continuous-output assets whose economics depend on both capital recovery and recurring operating cost.

Using the same modeled 2.5 MW distributed natural gas generation project discussed above, and applying a 50% capacity factor, the project's post-tax-incentive capital recovery requirement remains approximately 1.74 cents/kWh. When combined with non-fuel operating costs of approximately 2.0 cents/kWh and modeled fuel-cost assumptions ranging from approximately 2.5 cents/kWh to 3.79 cents/kWh depending on commodity natural gas prices, the estimated all-in revenue requirement increases to approximately 6.24 to 7.53 cents/kWh. These values reflect a more moderate and economically realistic utilization profile associated with field-deployed natural gas generation assets and demonstrate the sensitivity of project economics to fuel pricing, operational conditions, and dispatch decisions.

Fuel cost then becomes a primary driver of total required compensation. The U.S. Department of Energy's distributed-generation analysis shows that, at natural gas prices of $4, $6, $8, $10, and $12 per MMBtu, fuel cost alone ranges from 6.07 to 18.20 cents/kWh at 25% efficiency, 5.05 to 15.16 cents/kWh at 30% efficiency, 4.33 to 13.00 cents/kWh at 35% efficiency, and 3.79 to 11.37 cents/kWh at 40% efficiency.[70]

Because fuel expense varies directly with commodity natural gas pricing, distributed generation economics remain exposed to fuel-market volatility. At lower utilization levels, fixed capital and operating costs are spread across fewer annual kilowatt-hours, which further increases the importance of compensation structures capable of supporting long-term operational viability.

When these fuel-cost ranges are combined with the capital-plus-fixed-O&M requirements calculated above, the resulting levelized cost of energy rises and, in many cases, approaches or exceeds compensation levels tied to avoided wholesale procurement cost. By contrast, compensation closer to the retail default-service benchmark provides a greater opportunity to recover both fixed and recurring project costs. The economic significance of that spread is illustrated by the FirstEnergy Default Service calculations for the December 1, 2025 through May 31, 2026 period, which show residential and commercial Price-to-Compare ("PTC") rates of 10.947 cents/kWh and 10.993 cents/kWh, respectively, compared to current cost components of 9.103 cents/kWh and 8.717 cents/kWh, and loss-adjusted current cost components of 9.932 cents/kWh and 9.500 cents/kWh.[71] The filing further explains that the current cost component reflects the projected weighted cost of default-service supply, including PJM wholesale procurement costs, and incorporates class-specific loss factors of 1.0910 for residential service and 1.0899 for commercial service.[72]

[70] Nat'l Rural Elec. Coop. Ass'n, *White Paper on Distributed Generation* 13–14 (2007) (presenting fuel cost sensitivity ranges by natural gas price and generator efficiency).
[71] *Id*.
[72] *Id*.

Table 5. Illustrative LCOE Range Before Variable O&M and Compliance Costs (Modeled 2.5 MW distributed natural gas generation project; post-ITC capital recovery of 1.74¢/kWh; fixed O&M of 2.00¢/kWh; 50% capacity factor)

Electrical Efficiency	$4/MMBtu	$6/MMBtu	$8/MMBtu	$10/MMBtu	$12/MMBtu
25%	9.81¢/kWh	12.84¢/kWh	15.87¢/kWh	18.90¢/kWh	21.94¢/kWh
30%	8.79¢/kWh	11.32¢/kWh	13.85¢/kWh	16.38¢/kWh	18.90¢/kWh
35%	8.07¢/kWh	10.24¢/kWh	12.41¢/kWh	14.57¢/kWh	16.74¢/kWh
40%	7.53¢/kWh	9.43¢/kWh	11.32¢/kWh	13.22¢/kWh	15.11¢/kWh

Important note: These values still exclude engine overhaul reserves, emissions compliance, insurance, taxes, interconnection costs, financing structure effects, and any developer risk margin. They therefore remain conservative from the project sponsor's perspective and should not be interpreted as guaranteed project returns or complete all-in operating costs.

As Table 5 shows, once realistic fuel costs are added to capital recovery and fixed operating expense, the resulting LCOE for a gas-based customer-generator operating at a 50% capacity factor quickly approaches or exceeds avoided-cost compensation levels, particularly at lower efficiency levels or higher fuel prices. Even under the modeled project assumptions used here, relatively modest increases in commodity natural gas pricing compress project margins. In other words, as compensation trends downward toward avoided wholesale procurement cost, the margin available to recover fuel, maintenance, compliance, and project risk narrows quickly. For conventional gas customer-generators, that reduction can be the difference between an investable project and a project that remains uneconomic.

In that respect, the distinction between retail-based compensation and avoided-cost compensation is determinative. A compensation framework that fails to support capital recovery plus operating margin will not sustain private investment, regardless of broader policy objectives. Conversely, a framework that preserves sufficient revenue to cover both capital and operational costs enables continued deployment of privately financed generation, including projects that extend the productive life of existing natural gas assets.

In this respect, customer-generation does not alter the underlying market discipline; it operates within it. What it provides is an additional mechanism through which existing energy resources can be deployed efficiently, extending their useful life while contributing generation capacity to the grid. For Pennsylvania's substantial base of legacy oil and gas assets, that mechanism represents a direct means of preserving economic value through private investment. This additional economic value exists separately from the revenue generated through electricity sales and further improves overall project economics. In addition, when distributed generation offsets retail electricity consumption through a utility meter, the electricity produced provides the full retail value of that power to the system and the customer.

D. Market-Based Compensation and the Need for Investment Certainty

The U.S. Department of Energy, regional transmission organizations, and grid operators increasingly recognize that DERs can provide measurable operational and economic benefits to the electric system, including localized reliability support, peak shaving, ancillary services, deferred transmission and distribution investment, resilience benefits, and voltage and frequency support.[73]

At the same time, Pennsylvania has experienced increasing regulatory and utility opposition to existing customer-generation compensation structures. In several recent proceedings, electric distribution companies and parties before the Pennsylvania Public Utility Commission ("PUC") have sought to redefine customer-generator classifications, alter default service treatment, and modify compensation methodologies applicable to distributed generation facilities.[74] These proceedings demonstrate that the policy debate in Pennsylvania is no longer focused solely on encouraging distributed generation deployment, but increasingly on limiting the compensation mechanisms available to customer-generators. Utilities have argued that certain customer-generators create procurement volatility, increase default service costs, or impose cost-allocation burdens on non-participating customers. At the same time, the increasing focus on procurement impacts, transmission utilization, and distribution operations reflects the reality that DER deployment has become operationally significant to modern grid management.

For example, UGI asserted that grouping large customer-generators with smaller default-service customers would increase price volatility and procurement risk for other ratepayers, arguments ultimately accepted by the Commission and later affirmed by the Commonwealth Court.[75] Similarly, FirstEnergy Pennsylvania Electric Company recently proposed modifying default service classifications by incorporating "Maximum Registered Peak Load" calculations tied to customer-generator export capability, expressly stating that the purpose was to move larger customer-generators into hourly-priced default service classifications rather than traditional price-

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[73] U.S. Dep't of Energy, *Distributed Energy Resource Interconnection Roadmap: Transforming Interconnection by 2035* 9–21 (2025); ERCOT, *Distributed Energy Resources Operational Data: Value, Insights, and Technology Pathways for a Reliable Grid* 4–10 (2025).
[74] *Penn Renewables, LLC v. Pennsylvania Public Utility Commission*, No. 337 C.D. 2025 (Pa. Commw. Ct. Mar. 13, 2026); *Petition of FirstEnergy Pennsylvania Electric Company for Approval of Its Default Service Program for the Period June 1, 2027 to May 31, 2031*, Docket No. P-2026-3060298 (filed Feb. 3, 2026). ; *Pa. PUC v. Citizens' Electric Company of Lewisburg*, Docket No. R-2025-3054394 (Opinion and Order entered Jan. 15, 2026).
[75] Penn Renewables, No. 337 C.D. 2025, slip op. at 12–18.

to-compare structures.[76] Importantly, many of the current Pennsylvania proposals focus heavily on potential cost-allocation concerns while giving comparatively less attention to the substantial infrastructure contributions already borne by customer-generators themselves.

Contrary to the assertions made by the opposition, customer-generators routinely fund interconnection studies, transformer upgrades, relay protections, feeder improvements, and other distribution-system modifications as conditions of interconnection approval. In many cases, these utility-directed upgrades become permanent additions to the utility's infrastructure without requiring direct capital investment from the broader rate base.[77] Customer-generators also continue paying customer charges, distribution charges, and other grid-access costs associated with maintaining backup and balancing service from the utility system.

These realities undermine simplistic assertions that customer-generation merely "shifts costs" without corresponding system value. Although concerns regarding rate design and cost allocation warrant legitimate policy discussion, broad claims that distributed generation imposes net harm on non-participating customers frequently fail to account for avoided infrastructure costs, avoided line losses, reduced peak demand obligations, localized reliability benefits, deferred capital investment, and the private infrastructure expenditures already borne by customer-generators themselves. Multiple valuation studies and regulatory reviews have concluded that DERs provide measurable operational and economic benefits to the electric system when evaluated comprehensively.[78]

The frequently cited "cost-shift" narrative also depends heavily on assumptions that remain highly contested and, in many cases, incomplete. Chairman DeFrank's testimony projects that net metering costs could exceed $700 million annually if pending interconnection requests proceed under existing rules.[79] That projection, however, reflects gross compensation assumptions without fully accounting for the corresponding system benefits, avoided infrastructure costs, reduced transmission losses, deferred capital expenditures, and substantial interconnection investments already funded directly by customer-generators themselves.

The Chairman's cost-shift analysis identifies the projected gross compensation paid to net-metered customer-generators, but it does not complete the comparison that matters for energy policy. If, by

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[76] *Petition of FirstEnergy Pennsylvania Electric Company*, FE PA Statement No. 1, Direct Testimony of David M. Young at 15–20 (Feb. 3, 2026).
[77] Id. at 17–18.
[78] National Renewable Energy Laboratory, *State Strategies for Valuing Distributed Energy Resources in Cost-Effective Locations* 9–17 (2024); Rocky Mountain Institute, *Aggregated Distributed Energy Resources in 2024: The Fundamentals* 22–61 (2024).
[79] Prepared Testimony of Stephen M. DeFrank, Chairman, Pa. Pub. Util. Comm'n, before the House Energy Committee 2–3 (Mar. 2, 2026).

example, 1.5 GW of proposed customer-generation is viewed as a cost to ratepayers, then the alternative cost of procuring, constructing, interconnecting, and delivering an equivalent amount of centralized generation must also be considered. Developing several gigawatts of new centralized generation would require billions of dollars in capital investment, together with fuel costs, operations and maintenance expenses, financing costs, interconnection facilities, and, in many cases, significant transmission expansion. Those costs do not disappear; they are ultimately recovered from consumers through wholesale market prices, capacity charges, transmission rates, and other components of retail electric service. Those costs would ultimately be reflected in consumer bills through wholesale market prices, default service procurement costs, capacity charges, and transmission cost recovery mechanisms. A proper policy analysis therefore cannot compare customer-generation compensation to zero. It must compare customer-generation compensation to the cost of the supply and infrastructure that would otherwise be needed to serve the same growing demand.

A more fundamental problem underlies many of the "cost-shift" analyses advanced by Chairman DeFrank in his March 2026 testimony to the General Assembly and by utilities in recent proceedings. They implicitly assume that customer-generation should be valued using the same framework applied to utility default-service procurement. That assumption is flawed because customer-generation and default service perform fundamentally different functions within the electric system.

Default service is a procurement mechanism used by utilities to purchase electricity from centralized generators through competitive wholesale markets in an effort to obtain the lowest reasonable commodity price for customers who do not choose an alternative supplier. Customer-generation, however, is not a procurement resource. It is privately financed generation that is developed, interconnected, and operated by customers themselves, often at or near the location where the electricity is ultimately consumed.

That distinction matters because electricity is not valued solely by reference to its wholesale commodity price. Electricity derives value from where it is produced, where it is consumed, and what infrastructure is required to move it between those two points. A kilowatt-hour generated at or near load is not the economic equivalent of a kilowatt-hour procured from a distant generator and delivered through transmission and distribution infrastructure. In other words, electricity created by customer-generators, arrives with fewer losses, reduces reliance on centralized procurement, and may defer investments in generation, transmission, and distribution facilities. While reliance on centralized procurement requires those systems to be built, maintained, and paid for by consumers.

Treating customer-generation as though it were merely another source of wholesale supply therefore risks measuring the value of the electricity while ignoring the value of the infrastructure it may help avoid. The result is an incomplete comparison that focuses on the compensation paid to customer-generators without fully accounting for the costs that would otherwise be incurred to produce, procure, and deliver the same electricity through traditional means.

Importantly, many utility cost-shift analyses treat reductions in utility electricity sales as though they are themselves system "costs" imposed on other ratepayers. But reduced load is not inherently a system harm. To the contrary, reduced load growth can defer or eliminate the need for new transmission infrastructure, substations, feeder upgrades, generation procurement, and other capital expenditures that would otherwise be recovered from ratepayers through future utility rates.[80]

Recent analyses evaluating distributed generation and localized energy resources have concluded that DER deployment can materially reduce transmission and distribution investment requirements when integrated into long-term system planning.[81] In California, for example, distributed solar and energy efficiency deployment contributed to the cancellation or deferral of more than twenty transmission projects, avoiding approximately $2.6 billion in projected infrastructure expenditures that customers would otherwise have had to pay through utility rates and charges.[82] Similar avoided-cost principles are increasingly reflected in modern grid-planning literature and DER valuation methodologies nationwide.[83]

Nor does the "cost-shift" narrative fully account for the fact that customer-generators routinely finance substantial interconnection-related infrastructure improvements as conditions of interconnection approval. Transformer replacements, relay protection systems, feeder modifications, and distribution upgrades are frequently funded directly by the customer-generator rather than recovered from the broader rate base.[84] Those utility-directed investments remain part of the utility system long after the interconnection process is complete.

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[80] *The Utility "Cost Shift" Fallacy: How the Utilities Use Tricky Math to Vilify Rooftop Solar* 2–4 (Solar Rights Alliance 2021).
[81] National Renewable Energy Laboratory, *State Strategies for Valuing Distributed Energy Resources in Cost-Effective Locations* 9–17 (2024); Rocky Mountain Institute, *Aggregated Distributed Energy Resources in 2024: The Fundamentals* 22–61 (2024).
[82] *The Utility "Cost Shift" Fallacy*, supra note 20, at 1, 3–4.
[83] U.S. Dep't of Energy, *Distributed Energy Resource Interconnection Roadmap: Transforming Interconnection by 2035* 9–21 (2025).
[84] *Petition of FirstEnergy Pennsylvania Electric Company for Approval of Its Default Service Program*, FE PA Statement No. 1 at 17–18 (Feb. 3, 2026).

The relevant policy question, therefore, is not whether customer-generation has a cost. The question is whether compensating privately financed distributed generation is more or less expensive than requiring ratepayers to finance the centralized generation and infrastructure that would otherwise be needed to serve the same demand. A cost analysis that measures only the compensation paid to customer-generators, while ignoring the cost of the alternative supply resource, risks comparing a known cost to an assumed free substitute that does not exist. Increasingly, modern DER valuation studies conclude that the answer is highly dependent on methodology, system conditions, and whether the analysis measures only utility revenue impacts or broader system economics.[85] When measured on a net-system basis rather than a utility-revenue basis, customer-generation produces measurable net benefits for both the grid and ratepayers.

Pennsylvania-specific modeling demonstrates why that distinction matters. In a 2025 assessment prepared by The Brattle Group, analysts concluded that deploying 2 GW of commercial rooftop solar by 2031 would produce approximately $1.8 billion in cumulative net savings for Pennsylvania ratepayers, even after accounting for Solar Renewable Energy Credit ("SREC") costs paid to developers.[86] Brattle further concluded that distributed rooftop solar would reduce wholesale production costs, delay transmission and distribution investment, and provide capacity value during increasingly constrained PJM market conditions.[87] By 2031, the study projects that the average Pennsylvania household would save approximately $4.80 per month, or roughly $58 annually, as distributed solar moderates wholesale electricity prices and infrastructure-related cost pressures.[88]

The Brattle analysis is particularly important because it directly addresses the same market conditions underlying Chairman DeFrank's concerns.[89] Brattle projects that PJM will experience substantial supply constraints due to accelerating load growth, data center expansion, electrification, and the retirement of existing fossil-fuel generation.[90] Under those conditions, distributed rooftop solar reduces system costs by supplying low marginal-cost electricity during daylight hours, thereby lowering PJM market clearing prices and reducing the need for additional transmission infrastructure connecting distant generation resources to load centers.[91] Even

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[85] National Renewable Energy Laboratory, *State Strategies for Valuing Distributed Energy Resources in Cost-Effective Locations* 9–17 (2024).
[86] Tom Chapman, Ragini Sreenath & Audrey Yan, *Pennsylvania Value of Rooftop Solar Market Assessment* 5 (Brattle Group May 28, 2025).
[87] Id. at 4–5.
[88] Id. at 6, 22.
[89] The Chairman's concerns about the supposed "cost cliff", and the math and analysis surrounding those concerns, should be disclosed and transparent to all.
[90] Id. at 3, 15.
[91] *Id*. at 4–5.

relatively small reductions in hourly market clearing prices can generate substantial system-wide savings across PJM energy markets.[92]

These findings are consistent with broader DER valuation studies, which undermine the simplistic "cost-shift" narrative advanced by utilities and certain regulators. Modern distributed-resource valuation methodologies increasingly recognize avoided energy costs, avoided transmission and distribution costs, reduced line losses, deferred capacity additions, voltage-support benefits, resilience value, and localized reliability improvements as legitimate economic benefits attributable to customer-generation.[93] The National Renewable Energy Laboratory ("NREL") has specifically recognized that distributed resources can reduce or defer investments in transmission and distribution infrastructure when integrated into long-term grid planning.[94]

Importantly, many utility cost-shift studies rely on accounting assumptions that treat customer self-generation and reduced utility sales as though they are themselves economic harms imposed on other ratepayers. But lower load growth is not inherently a system cost. Reduced demand for centrally supplied electricity can defer or eliminate the need for new substations, feeder upgrades, transmission projects, and generation procurement costs that would otherwise be recovered through future utility rates.[95] Indeed, California grid operators previously canceled or deferred more than twenty transmission projects due in part to increased distributed solar deployment and energy efficiency, avoiding approximately $2.6 billion in projected infrastructure expenditures.[96]

Nor does the cost-shift narrative adequately account for the substantial utility-system upgrades already financed by customer-generators themselves. Customer-generators routinely pay for interconnection studies, transformer upgrades, relay protections, feeder modifications, and other utility-directed infrastructure improvements required as conditions of interconnection approval.[97] These investments become permanent additions to utility infrastructure without requiring equivalent upfront capital expenditures from the broader rate base. In practical terms, customer-generators are not merely reducing load; they are privately financing portions of the electric system itself.

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[92] *Id*. at 11–12.
[93] National Renewable Energy Laboratory, *State Strategies for Valuing Distributed Energy Resources in Cost-Effective Locations* 9–17 (2024); Rocky Mountain Institute, *Aggregated Distributed Energy Resources in 2024: The Fundamentals* 22–61 (2024).
[94] National Renewable Energy Laboratory, *State Strategies for Valuing Distributed Energy Resources in Cost-Effective Locations* 9–17 (2024).
[95] *The Utility "Cost Shift" Fallacy: How the Utilities Use Tricky Math to Vilify Rooftop Solar* 2–4 (Solar Rights Alliance 2021).
[96] Id. at 1, 3–4.
[97] Petition of FirstEnergy Pennsylvania Electric Company for Approval of Its Default Service Program, FE PA Statement No. 1 at 17–18 (Feb. 3, 2026).

The cost-shift narrative also overlooks a broader economic reality: rising electric rates in Pennsylvania and throughout PJM are being driven principally by escalating infrastructure costs, transmission expansion, fuel-price volatility, generation retirements, and constrained supply conditions, and not by customer-generation. The Pennsylvania Public Utility Commission's own Electric Power Outlook reported approximately $898.47 million in PJM Regional Transmission Expansion Plan ("RTEP") investment associated with Pennsylvania projects in 2023 alone, up substantially from prior years.[98] At the same time, PJM capacity prices and wholesale market costs have increased sharply due to tightening reserve margins and delayed generation additions.[99] By way of example, the PJM capacity auction clearing price increased from $28.92/MW-day for the 2024/2025 delivery year to $269.92/MW-day for the 2025/2026 delivery year—an increase of more than 830% in a single auction cycle.[100] Against that backdrop, customer-generation is not the source of rising system costs. To the contrary, distributed generation represents one of the few immediately deployable resources capable of moderating future infrastructure and procurement expenditures.

The operational logic underlying these conclusions is straightforward. Distributed generation located near load reduces the amount of electricity that must travel through congested transmission and distribution infrastructure. This localized generation can reduce peak loading on substations and feeder circuits, lower line losses, defer infrastructure upgrades, and improve voltage support. Distributed resources may also provide capacity value precisely where the system is experiencing the greatest operational stress, particularly during periods of constrained supply or high peak demand.[101] Pennsylvania's long-term reliability, affordability, and supply objectives are best served by maintaining a framework that allows private actors to invest in generation resources under stable and predictable rules that reflect the value those resources provide to the electric system.

Customer-generation aligns with principles that have historically commanded bipartisan support across energy policy and infrastructure development. It promotes private investment rather than public expenditure. It encourages competition by allowing new market participants to develop generation resources outside of traditional utility ownership structures. It enhances energy security by diversifying supply and reducing reliance on centralized infrastructure. And it supports

[98] Pennsylvania Public Utility Commission, *Electric Power Outlook for Pennsylvania* 2023–2028 21–22 (2024).
[99] Chapman *et al*., supra note 21, at 15, 19–22.
[100] PJM Interconnection, L.L.C., 2025/2026 Base Residual Auction Results, available at https://www.pjm.com/markets-and-operations/rpm.aspx (showing an increase in the RTO clearing price from $28.92/MW-day for the 2024/2025 delivery year to $269.92/MW-day for the 2025/2026 delivery year, an increase of approximately 833%).
[101] Rocky Mountain Institute, *The Economics of Distributed Energy Resources* (2023).

economic development by directing private capital into local engineering services, construction activity, equipment procurement, and ongoing operations within Pennsylvania communities.[102]

Unlike utility-owned infrastructure, which is ultimately recovered through regulated rates charged to captive customers, customer-generation projects are financed principally through private capital deployed at investor risk.[103] At a time when Pennsylvania and the broader PJM region are confronting substantial projected load growth, increasing transmission investment requirements, and resource adequacy concerns, customer-generation represents a form of infrastructure deployment that supplements system supply without requiring equivalent upfront utility capital expenditures recoverable from the broader rate base or default service procurements.

Importantly, preserving investment certainty does not require ignoring legitimate affordability concerns or broader system obligations. Policymakers may reasonably consider targeted and transparent adjustments designed to address specific public-interest cost components while preserving compensation structures that remain sufficiently stable to support continued private infrastructure investment.

One potential framework is a targeted "Consumer Protection Adjustment" applied to customer-generator compensation. Under such an approach, customer-generators would continue receiving compensation tied to the retail value of electricity supplied to the grid, while a narrowly tailored adjustment would account for specifically identifiable public-interest cost components borne by the broader customer class. Such components could include utility-specific uncollectible account expense, universal service obligations, and gross receipts tax recovery.

Unlike proposals that would fundamentally restructure customer-generation compensation around wholesale market pricing or hourly default-service constructs, a Consumer Protection Adjustment preserves the core economic predictability necessary to finance distributed generation infrastructure while directly addressing concerns regarding affordability and equitable cost allocation. By tying the adjustment to transparent and measurable utility cost inputs, the framework avoids arbitrary compensation reductions while ensuring that customer-generators continue contributing toward clearly identifiable public-interest obligations.

Such an approach also reflects broader ratemaking principles already utilized elsewhere in Pennsylvania utility regulation. The Commission routinely approves riders, reconcilable surcharges, universal service mechanisms, and formulaic adjustments designed to recover specific

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[102] U.S. Dep't of Energy, *Distributed Energy Resource Interconnection Roadmap: Transforming Interconnection by 2035* 9–21 (2025).
[103] Doerfler & Toering, supra note 1, at 169–76.

categories of public-interest costs from identifiable customer classes.[104] A targeted Consumer Protection Adjustment would operate similarly by recognizing that customer-generators, while providing measurable system benefits, may still appropriately contribute to limited categories of broader system obligations.

Concerns regarding investment certainty are not unique to distributed generation. Utilities themselves routinely seek regulatory mechanisms designed to reduce investment risk and stabilize cost recovery. Long-term rate recovery, stranded cost protections, formula rate mechanisms, and guaranteed return structures all reflect the broader regulatory recognition that infrastructure investment depends upon predictable rules and stable compensation frameworks. As one recent legal analysis observed, abrupt changes to net metering structures create a "stranded costs double standard" whereby utilities seek protection for their own investments while simultaneously impairing the settled investment expectations of customer-generators.[105]

The consequences of regulatory instability are not theoretical. Following abrupt changes to net metering compensation structures in Nevada, distributed solar deployment and associated private investment declined until subsequent policy revisions restored greater market certainty.[106] More broadly, legal and economic studies consistently demonstrate that regulatory instability increases financing costs, suppresses deployment, and discourages long-term capital formation in energy infrastructure markets.[107]

Accordingly, any reforms to Pennsylvania's customer-generation framework should carefully distinguish between legitimate concerns regarding cost allocation and proposals that undermine investment predictability through abrupt or retroactive compensation changes. Policymakers may reasonably consider prospective reforms tied to transparent avoided-cost methodologies, updated interconnection practices, or more granular rate design. However, those reforms should preserve reliance interests, maintain investment stability, and recognize the increasingly important operational role that distributed resources play in supporting grid reliability, resilience, affordability, and long-term energy security. Policies that preserve investment certainty while aligning compensation with demonstrable system value are therefore more likely to support long-term affordability and reliability objectives than policies that destabilize distributed generation investment altogether.

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[104] See 66 Pa.C.S. §§ 1307, 1404, 2807(e); *Pa. PUC v. Citizens' Electric Company of Lewisburg*, Docket No. R-2025-3054394 (Opinion and Order entered Jan. 15, 2026).
[105] Doerfler & Toering, supra note 1, at 169–76.
[106] Pieter Gagnon et al., *The Impacts of Changes to Nevada's Net Metering Policy on the Financial Performance and Adoption of Distributed Photovoltaics* (Nat'l Renewable Energy Lab. 2017).
[107] Doerfler & Toering, supra note 1, at 169–76.

V. The Legislative Answer

The policy debate presently unfolding in Pennsylvania should not be understood as a dispute over whether distributed generation merely supplements the existing electric system. The electric system itself is changing. For more than a century, the modern grid was built around large, centralized generation facilities connected through long-distance transmission infrastructure and supported through capital-intensive utility investment models. That structure reflected the technological and economic assumptions of the twentieth century, when generation economies of scale favored progressively larger power plants and when electricity could only be produced economically through centralized deployment. Those assumptions, however, are no longer fully applicable.

Technological advances in distributed generation, energy storage, digital controls, and aggregation platforms are fundamentally altering how electricity can be produced, deployed, and managed across the grid. Modern distributed energy resources are increasingly modular, scalable, dispatchable, and capable of operating at commercial and even manufacturing scale.[108] Advanced reciprocating engines, combined heat and power systems, microgrids, virtual power plant architectures, and distributed storage platforms now allow electricity production to occur closer to load, at smaller increments, and with far shorter development timelines than traditional utility-scale infrastructure.

The rapid growth of artificial intelligence infrastructure has accelerated this transition. Recent projections estimate that data center demand may account for nearly half of projected electricity load growth over the next decade in certain regions of the United States.[109] In response, large-load customers are increasingly deploying distributed natural gas generation, solar-plus-storage systems, and hybrid energy architectures capable of reducing transmission dependence and supplying capacity directly into local systems.[110] These developments expose an increasingly important reality: the traditional centralized utility model is no longer the sole mechanism through which generation supply can be deployed at scale.

At the same time, the legacy grid remains under substantial strain. Much of Pennsylvania's transmission and distribution infrastructure was constructed decades ago under fundamentally

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[108] National Renewable Energy Laboratory, *White Paper: Enabling Regulatory and Business Models for Broad Microgrid Deployment* iv–v (2022); Amory B. Lovins, *Small Is Profitable: The Hidden Economic Benefits of Distributed Generation* 1–5 (Rocky Mountain Institute 2002).

[109] Id. at 2; Eleftherios Iakovou et al., *Meeting Rising U.S. Electricity Demand from AI and Data Centers: An Integrated Technical and Policy Perspective* 1–3 (Mosbacher Inst. 2025).

[110] Iakovou et al., supra note 3, at 7–12; U.S. Dep't of Energy, *DOE Resources Available to Support Data Center Electricity Needs* 1–8 (2025).

different load assumptions.[111] Utilities throughout the PJM region are confronting increasing transmission congestion, aging infrastructure, long interconnection queues, rising capital expenditures, and accelerating demand growth associated with electrification and data center development.[112] NERC has likewise warned that portions of the Eastern Interconnection face increasing reliability risks as load growth outpaces the pace of new centralized generation additions.[113] Under these conditions, customer-generation should be understood not as a marginal policy accommodation, but as part of the broader structural evolution of the electric system itself.

In Pennsylvania, customer-generators finance and deploy generation assets at investor risk, assume responsibility for interconnection and operational expenditures, and contribute supply without requiring equivalent utility-owned capital investment recoverable from ratepayers. In many cases, distributed generation resources can be deployed faster than traditional centralized infrastructure projects and can be located closer to emerging load growth.

This dynamic is particularly important because the Commonwealth possesses substantial existing energy infrastructure capable of supporting distributed generation deployment, including conventional natural gas production, legacy well infrastructure, industrial energy assets, and geographically dispersed production regions. These existing assets increasingly provide a platform for distributed generation systems capable of supporting localized load, manufacturing facilities, industrial development, and computational infrastructure while reducing pressure on constrained transmission systems.

Importantly, recognizing this structural transformation does not require abandoning centralized infrastructure altogether. Large-scale transmission and utility-scale generation will remain important components of the electric system for the foreseeable future. But the existence of continuing utility infrastructure needs does not diminish the significance of distributed generation's expanding role. Rather, it underscores why Pennsylvania should avoid policies that unnecessarily suppress privately financed supply during a period of accelerating system demand.

Any legislative response should therefore proceed cautiously. Broad efforts to narrow customer-generator eligibility, destabilize compensation structures, or redefine distributed generation participation through administrative mechanisms risk discouraging private investment precisely when the electric system is becoming increasingly dependent upon flexible, modular, and rapidly deployable generation resources.

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[111] Am. Soc'y of Civ. Eng'rs, *2022 Pennsylvania Infrastructure Report Card.*
[112] Pennsylvania Public Utility Commission, *Electric Power Outlook for Pennsylvania* 2023–2028, at 2–7 (2024).
[113] North American Electric Reliability Corporation, *2025 Long-Term Reliability Assessment* 15–22 (2025).

This is especially critical at a time when PJM is projecting sustained load growth, transmission expansion is becoming increasingly expensive and time-intensive, and large-load customers are already moving toward distributed generation architectures. Pennsylvania should be careful not to anchor future policy exclusively to a legacy model of electricity deployment that the market itself is already evolving beyond.

VI. The Risk of Overcorrection

A. Fewer Projects and Less Distributed Supply

As mentioned above, customer-generation development is highly sensitive to compensation structures, eligibility standards, and regulatory stability. Distributed generation projects require substantial upfront capital investment, long development timelines, utility interconnection coordination, financing commitments, and ongoing operational expenditures. As a result, abrupt policy changes or broad eligibility restrictions affect investment behavior almost immediately.

Changes to customer-generator compensation or classification do not take years to influence market behavior but, rather, can slow or collapse rapidly once financing markets perceive regulatory instability. Projects already under development may be delayed or cancelled. Capital shifts elsewhere. Developers, lenders, and customers reprice risk or redirect investment into jurisdictions where the governing framework appears more stable and predictable.

The national experience with abrupt net metering changes demonstrates these effects clearly. Nevada's 2016 revisions to net metering compensation reduced projected distributed solar deployment and disrupted ongoing market development.[114] Recent legal and economic research consistently concludes that abrupt compensation changes increase financing costs, suppress deployment, and discourage long-term infrastructure investment in distributed generation markets.[115]

Accordingly, reducing the viability of customer-generation necessarily reduces future supply additions. A weakened framework therefore reduces available supply at precisely the moment additional supply flexibility is becoming increasingly important to maintaining reliability and affordability.

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[114] Pieter Gagnon et al., *The Impacts of Changes to Nevada's Net Metering Policy on the Financial Performance and Adoption of Distributed Photovoltaics* (Nat'l Renewable Energy Lab. 2017).
[115] Emily Doerfler & Cameron Toering, *Stranded Costs and Double Standards: The Case Against Abrupt Changes to Net Metering Programs,* 12 LSU J. Energy L. & Res. 153, 169–76 (2024).

B. Greater Reliance on Traditional Utility Buildout

If customer-generation declines, the system must replace that lost supply elsewhere. In real terms, this means increased reliance on centralized generation development, transmission expansion, and utility-driven infrastructure investment.

These alternatives are slower, more capital intensive, and more likely to be financed through rates borne by captive ratepayers. Utility infrastructure projects frequently require extensive permitting, multi-year development cycles, major transmission upgrades, and substantial capital expenditures ultimately recovered through regulated cost-recovery structures.[116]

The PA PUC has already acknowledged the substantial increase in transmission-related costs borne by customers. Chairman DeFrank recently testified that transmission costs within PJM increased from approximately $3.50/MWh in 2001 to approximately $17.70/MWh by 2021, representing an increase of roughly 400 percent.[117] At the same time, PJM and NERC continue to warn that resource adequacy risks may emerge as future load growth outpaces new generation additions.[118]

Distributed generation helps mitigate these pressures by supplying electricity closer to load and reducing the need for certain transmission and distribution upgrades. The U.S. Department of Energy has specifically identified the ability of distributed generation to defer transmission and distribution investment that otherwise would be recovered through customer rates.[119] Federal and industry studies likewise recognize that distributed resources can reduce congestion, reduce line losses, improve localized reliability, and reduce infrastructure expansion pressures when deployed strategically.[120]

Reducing distributed supply therefore increases dependence on slower and more expensive utility infrastructure expansion, at a time when utilities and regulators are already confronting escalating capital requirements across the grid.

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[116] Pennsylvania Public Utility Commission, *Electric Power Outlook for Pennsylvania 2023–2028*, at 2–7 (2024).
[117] Prepared Testimony of Gladys Brown Dutrieuille & Stephen M. DeFrank before the Pennsylvania Senate Consumer Protection and Professional Licensure Committee 6–7 (June 20, 2023).
[118] PJM Resource Adequacy Planning Department, *2026 PJM Load Forecast Report* (Jan. 14, 2026); North American Electric Reliability Corporation, *2025 Long-Term Reliability Assessment* 15–22 (2025).
[119] U.S. Dep't of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Its Expansion* 14–21 (2007).
[120] Michael E. Birk, *Impact of Distributed Energy Resources on Locational Marginal Prices and Electricity Networks* 30–35 (M.S. thesis, Massachusetts Institute of Technology 2016); National Renewable Energy Laboratory, Distributed Energy Planning for Climate Resilience (2018).

C. Worse Timing Could Hardly Be Imagined

Pennsylvania is confronting rising demand, infrastructure constraints, and increasing electricity costs simultaneously. PJM has identified data centers, artificial intelligence infrastructure, industrial growth, and electrification as major drivers of accelerating demand growth.[121] National reliability assessments similarly warn that large-load growth and emerging computational facilities are creating new reliability risks for the bulk power system.[122]

Weakening customer-generation under these conditions would reduce one of the fastest and most scalable forms of supply while increasing dependence on longer-term centralized infrastructure expansion. The likely result would be higher capital requirements, greater pressure on transmission systems, and increased long-term costs for customers.

Distributed generation alone cannot satisfy all future electricity needs. Nor should it be expected to. But reducing distributed supply options while load growth accelerates would move Pennsylvania in the wrong direction. The Commonwealth should not respond to increasing electricity demand by discouraging resources that already contribute supply, support localized reliability, and reduce infrastructure burdens on the broader electric system.

VII. Legislative Principles for a Balanced Path Forward

A. Protect Customer-Generators as a Recognized Class

The AEPS Act already establishes the legal and regulatory framework governing customer-generators, including eligibility standards, participation rights, interconnection authority, and net metering treatment.[123] Those core statutory elements should remain intact.

Customer-generators should continue to be treated, first and foremost, as ratepaying customers of the utility and as a recognized class of distributed resource participants under Pennsylvania law. Customer-generators are retail customers of the utility system who remain subject to distribution charges, interconnection requirements, and utility service obligations under the AEPS framework. They are not wholesale market participants, generation suppliers, or default service providers, and should not be treated as though they participate in the utility's default service procurement process merely because excess electricity may be exported to the grid under statutorily authorized net

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[121] PJM Resource Adequacy Planning Department, *2026 PJM Load Forecast Report* (Jan. 14, 2026).
[122] North American Electric Reliability Corporation, *Characteristics and Risks of Emerging Large Loads* 1–7 (2025).
[123] 73 P.S. §§ 1648.1–1648.8; 52 Pa. Code §§ 75.1–75.75.

metering arrangements. Any future legislative reforms should preserve this distinction clearly and expressly.

This distinction is increasingly important as distributed generation becomes more integrated into broader grid planning and system operations. PJM and NERC have both identified accelerating load growth, resource adequacy concerns, and transmission constraints as emerging challenges throughout the region.[124] Under those conditions, preserving legally recognized pathways for generation supports the broader reliability and affordability objectives of the electric system.

The General Assembly should therefore avoid reclassification mechanisms or administrative approaches that effectively narrow the customer-generator framework without clear legislative direction.

B. Preserve Technology Neutrality

Pennsylvania's distributed generation framework should remain technology neutral across qualifying Tier I and Tier II resources recognized under the AEPS Act.[125] Technology neutrality promotes investment diversity, supports innovation, and allows customer-generators to deploy resources best suited to local operational, economic, and reliability conditions. This principle is particularly important where dispatchable distributed generation technologies, including systems associated with conventional natural gas infrastructure, can provide firm localized supply and resiliency benefits distinct from intermittent resources.

Modern distributed energy systems increasingly operate as integrated portfolios combining generation, storage, demand flexibility, and digital control technologies.[126] Preserving technology neutrality allows markets, rather than rigid regulatory preferences, to determine which combinations of resources can most effectively support evolving grid conditions.

Technology neutrality also better aligns with the Commonwealth's historical approach to energy policy. Pennsylvania has long benefited from a diversified generation portfolio that includes natural gas, nuclear energy, coal, renewables, and distributed resources. Maintaining flexibility across multiple distributed generation technologies is therefore more consistent with the

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[124] PJM Resource Adequacy Planning Department, *2026 PJM Load Forecast Report* (Jan. 14, 2026); North American Electric Reliability Corporation, 2025 Long-Term Reliability Assessment 15–22 (2025).
[125] 73 P.S. § 1648.2.
[126] National Renewable Energy Laboratory, *White Paper: Enabling Regulatory and Business Models for Broad Microgrid Deployment* iv–v (2022); Federal Energy Regulatory Commission, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 2222, 172 FERC ¶ 61,247 (2020).

Commonwealth's reliability and affordability objectives than restricting participation to a narrow set of preferred technologies.

C. Avoid Retroactive or Destabilizing Changes

Customer-generators, lenders, developers, equipment providers, and businesses have invested substantial capital in reliance upon the legal framework established under the AEPS Act and the Commission's implementing regulations. Those investments frequently involve long-duration financing structures, interconnection expenditures, engineering costs, equipment procurement, and multi-year project development timelines.

Retroactive or destabilizing changes to compensation structures or eligibility standards undermine investment predictability and create avoidable regulatory risk. Recent legal scholarship examining abrupt net metering reforms has observed that such changes can produce a "stranded costs double standard," whereby utilities seek protection for their own capital investments while impairing the settled expectations of customer-generators operating under previously established regulatory frameworks.[127]

D. If Reforms Are Considered, Make Them Narrow and Prospective

To the extent policymakers identify concerns associated with specific configurations, procurement structures, or operational impacts, reforms should be targeted narrowly to those demonstrated issues.

Broad restructuring of customer-generator eligibility, compensation, or classification risks affecting the entire distributed generation market far beyond the particular circumstances policymakers may seek to address. Such broad changes can unintentionally impair investment across distributed generation technologies and project categories that do not contribute to the identified concern.

Pennsylvania can address discrete issues without destabilizing the broader customer-generator framework. If modifications are pursued, they should therefore be carefully drafted, limited in scope, transparent in operation, and applied prospectively.

Prospective reforms preserve the ability of policymakers to adapt to evolving system conditions while respecting settled investment expectations and avoiding retroactive impairment of

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[127] Emily Doerfler & Cameron Toering, *Stranded Costs and Double Standards: The Case Against Abrupt Changes to Net Metering Programs,* 12 LSU J. Energy L. & Res. 153, 169–76 (2024).

previously financed infrastructure. This approach better balances legitimate regulatory flexibility with the market stability necessary to support continued private infrastructure investment.

E. Align Policy with Pennsylvania's Actual Needs

Pennsylvania's energy policy should align with the Commonwealth's actual electric system needs: affordability, reliability, resiliency, supply adequacy, and sustained infrastructure investment.

Customer-generators support those objectives by adding distributed supply, reducing localized infrastructure pressures, and contributing operational flexibility to the electric system. Distributed generation resources can complement centralized generation and transmission infrastructure while reducing dependence on any single pathway for meeting future demand growth. Policies that suppress distributed generation move the Commonwealth further away from its long-term energy objectives, not closer to them.

A balanced path forward therefore preserves customer-generation as part of a diversified energy strategy capable of supporting affordability, reliability, resiliency, investment stability, and economic growth for Pennsylvania consumers and businesses alike.

VIII. Conclusion

Pennsylvania's electric system is entering a period of transition that will shape the Commonwealth's economy, infrastructure, and energy markets for decades to come. The assumptions that governed electric system planning for much of the last century, i.e., steady load growth, centralized generation, and long development cycles, no longer fully reflect present conditions. Demand is accelerating, transmission constraints are becoming more acute, and technological advances are changing how generation can be deployed across the grid.

Customer-generation has emerged within that transition not as a theoretical policy concept, but as a practical source of privately financed supply. Distributed generation allows electricity to be developed closer to load, deployed more quickly, and financed without requiring equivalent utility capital expenditures recoverable from ratepayers. In Pennsylvania, it also creates a productive use for existing energy infrastructure, including conventional natural gas assets that might otherwise face declining economic utility.

At the same time, the Commonwealth is confronting increasing pressure on the electric system itself. PJM projects sustained load growth associated with data centers, electrification, and industrial expansion. Transmission investment is becoming more expensive and time-intensive, while reliability organizations continue warning that future resource additions may struggle to keep pace with projected demand. Under those conditions, policies that discourage privately financed generation do not reduce system risk; they increase dependence on slower and more capital-intensive infrastructure expansion.

None of this suggests that customer-generation should exist outside reasonable regulatory oversight. The electric system will continue to require centralized infrastructure, transmission investment, and careful planning. But the policy response to changing system conditions should be measured and precise. Broad efforts to narrow customer-generator eligibility, destabilize compensation structures, or collapse customer-generation into default service constructs risk undermining the very investment signals that have enabled distributed generation to contribute supply, flexibility, and resiliency to the grid.

The larger point is difficult to ignore: the electric system is already evolving toward smaller, more distributed, and more flexible forms of generation. Large-load customers increasingly seek localized power solutions. Distributed generation technologies continue to improve. Private capital continues to move toward projects capable of being deployed closer to demand. The market is adapting to the realities of modern load growth and infrastructure constraints, whether regulation evolves with it or not.

Pennsylvania therefore faces a consequential choice. It can preserve a stable, technology-neutral framework that allows private investment to continue supporting supply and grid flexibility. Or it can retreat toward a model that depends more heavily on centralized buildout, longer timelines, and increasing ratepayer exposure to infrastructure costs.

At a moment when the Commonwealth needs more supply, more flexibility, and more investment, the better course is not to narrow the pathways for generation, but to preserve the conditions under which new generation can continue to emerge.