

# Behind-the-Meter Optimization

## and the Rise of Energy-as-a-Service

WHITEPAPER



- +1 463-266-4496
- [www.vedeni.energy](http://www.vedeni.energy)
- [info@vedeni.energy](mailto:info@vedeni.energy)
- Whitestown, in 46075, US.



# Executive Summary

Commercial and industrial energy strategy is shifting from passive procurement to active energy management. For decades, most large customers treated electricity as a delivered commodity, managed through tariff selection, competitive supply contracts where available, and periodic efficiency projects. That model is no longer sufficient. Rising peak demand, greater exposure to demand charges, extreme weather, grid congestion, decarbonization commitments, electrification of fleets and industrial processes, and heightened sensitivity to outages are forcing customers to treat energy as an operating platform. Behind-the-meter energy solutions—solar, battery storage, microgrids, building controls, backup generation, electric vehicle charging infrastructure, and customer energy management systems—are becoming integral to the core facilities, finance, risk, and sustainability agenda.

The rise of energy as a service reflects this shift. In an Energy-as-a-Service model, a third-party provider finances, designs, builds, owns, operates, and manages distributed energy assets for a customer under a long-term service agreement. The customer may avoid upfront capital investment, transfer technical and operational risk, secure predictable pricing, and access expertise that would be difficult to build internally. The provider, in turn, creates value by aggregating project finance, technology integration, data analytics, maintenance, market participation, and performance management. In its most advanced form, Energy-as-a-Service is not merely a financing structure. It is a distributed energy business model that converts behind-the-meter assets into a managed portfolio capable of reducing bills, improving resilience, supporting decarbonization, and potentially delivering services to utilities and wholesale markets.

The opportunity is significant, but it is not frictionless. The U.S. electricity sector's regulatory structure was built around vertically integrated utilities, franchised distribution service, central station generation, and one-way power flows. Behind-the-meter optimization challenges that structure. Retail rate design can reward or discourage flexible load. Interconnection procedures can accelerate or delay projects. Net metering and net billing policies affect the economics of solar-plus-storage. Utility standby charges, demand ratchets, export restrictions, and data-access rules can make or break customer value. Wholesale market access under FERC Order No. 2222 creates a path for distributed energy resource aggregations, but implementation remains complicated because DERs sit at the intersection of customer facilities, distribution utility operations, state regulation, and regional transmission organization or independent system operator markets.

For utilities and grid operators, the implications are substantial. Behind-the-meter resources can reduce peak demand, defer distribution investment, improve local resilience, and provide flexibility as load growth resumes after years of relative stagnation. They can also create challenges for visibility, forecasting, coordination, cybersecurity, and cost allocation. A battery that optimizes a customer's demand charge may not automatically optimize the feeder, the local substation, the transmission interface, or the bulk power system. A microgrid that improves resilience for a hospital, manufacturing plant, port, airport, or data center may reduce utility revenue while increasing the need for more sophisticated distribution planning. The future value of Energy-as-a-Service will therefore depend on whether customer economics, utility planning, and market rules can be better aligned.

# From Passive Load to Active Energy Platforms

The traditional commercial and industrial customer relationship with the electric grid was built on a simple bargain. The utility provided reliable service, the customer paid for consumption and peak demand, and energy management was largely limited to conservation, procurement, and backup generation. Large customers might negotiate special contracts or participate in demand response programs, but the physical energy system behind the meter remained largely static. Lighting retrofits, chiller upgrades, power-factor correction, and emergency generators were important, but they did not fundamentally change the customer's role in the electric system.

That model is breaking down because the economics of electricity have become more dynamic. The cost of energy is no longer adequately captured by kilowatt-hours alone. For many commercial and industrial customers, demand charges, coincident peak exposure, time-of-use periods, power quality events, outage risk, emissions reporting, and capital planning are now part of the same problem. A warehouse with rooftop solar may still face high evening demand charges. A cold-storage facility may be able to shift load but cannot risk product loss. A manufacturer may value resilience more than energy savings because even a short interruption can shut down production lines. A data center may prioritize power quality, redundancy, and speed to energization over simple retail-rate arbitrage. A university, hospital, airport, or military installation may need energy assets that support both sustainability and mission continuity.





Behind-the-meter optimization addresses this broader problem. It treats the customer site as an energy system rather than a passive load. Solar generation can reduce grid purchases during daylight hours. Batteries can reduce demand charges, shift energy consumption across time-of-use periods, provide backup power, and support participation in demand response or other grid services programs. Building automation systems can control HVAC, lighting, refrigeration, process loads, and thermal storage. Microgrid controllers can coordinate generation, storage, and load during both grid-connected and islanded operation. Customer energy management systems provide the software layer needed to forecast load, respond to tariffs, manage carbon objectives, and execute dispatch decisions.

The term commercial energy optimization is useful because it captures the operating logic behind these investments. The objective is not simply to install more devices. It is to manage energy outcomes across cost, reliability, resilience, emissions, operational constraints, and financial risk. A poorly integrated solar-plus-storage system may underperform even if the individual assets are well designed. A building controls project may save energy but fail to deliver resilience. A battery may reduce one tariff component while increasing another. A microgrid may be technically impressive but financially weak if it lacks a clear dispatch strategy. The business case increasingly depends on integrated design and active management.



- ▶ Businesses are shifting from **passive energy use** to **active energy management** due to more complex electricity costs and reliability needs.
- ▶ **Integrated systems** (solar, batteries, automation) now optimize cost, resilience, and performance—not just energy consumption.



## The Building Blocks

# Behind-the-Meter Energy Solutions

Behind-the-meter energy solutions typically draw on several resource classes. Solar photovoltaic systems remain the most visible because they are modular, mature, and often economically attractive when roof space, land, incentives, and tariff structures align. For commercial and industrial customers, solar can reduce energy purchases, support sustainability goals, and hedge a portion of future electricity price exposure. Yet solar alone has limitations. Its production profile may not match a facility's demand profile, particularly when peak demand occurs in the late afternoon or evening, or during process-driven operating cycles. Export compensation may be limited, and high solar penetration can create operational issues on distribution circuits.

Battery storage addresses some of those limitations. For customers with high demand charges, batteries can discharge during short peaks to reduce billed demand. Under time-of-use rates, batteries can charge during lower-cost periods and discharge during higher-cost periods. In facilities with critical loads, batteries can bridge short outages, support seamless transfer to backup generation, or be part of a larger microgrid. Batteries can also provide grid services when market rules, metering, telemetry, and aggregation structures permit. However, battery economics are highly sensitive to use-case stacking. A battery justified solely by demand-charge management may have a narrow revenue base. A battery that also supports resilience, demand response, capacity value, renewable integration, and power quality may have a stronger business case, but only if contractual rights and operating priorities are clearly defined. Published U.S. storage statistics often emphasize utility-scale additions, so they should not be read as a direct one-for-one measure of customer-sited storage adoption. Even so, the same cost declines, software advances, interconnection practices, and value-stacking logic that support grid-scale storage are also influencing behind-the-meter storage and Energy-as-a-Service offerings.

Energy management systems serve as the control layer that turns assets into an optimization platform. Modern customer energy management systems use interval data, tariff logic, weather forecasts, occupancy patterns, production schedules, battery state of charge, solar forecasts, and

operational constraints to make dispatch decisions. The value of these systems is growing as customer sites become more complex. A commercial building may have rooftop solar, a battery, electric vehicle chargers, automated HVAC, controllable lighting, and tenant-specific operating requirements. An industrial site may have process loads that cannot be interrupted, backup generators with emissions limits, power quality requirements, and corporate carbon reporting obligations. Without effective controls, the customer owns equipment. With effective controls, the customer has an energy strategy.

Microgrids are the most comprehensive form of behind-the-meter optimization. A microgrid integrates local generation, storage, controls, and load management into a system that can operate in parallel with the grid or independently during outages. In the commercial and industrial sector, microgrids are most compelling when outage costs are high, power quality is critical, grid interconnection is delayed, or the customer has strong sustainability and resilience objectives. Hospitals, ports, airports, universities, military facilities, water treatment plants, logistics hubs, food processing facilities, semiconductor plants, and data centers are natural candidates. The economics vary by site, but the strategic appeal is straightforward: the customer gains a managed energy system rather than a collection of separate assets.

Backup generation remains part of the picture, particularly for resilience. Diesel and natural gas generators are familiar, dispatchable, and often required for emergency power. Yet they are increasingly integrated with batteries, solar, and controls rather than operating alone. This integration can reduce fuel use, improve ride-through performance, manage generator loading, and enable more flexible operating modes. In some regions, emissions limits and permitting requirements constrain generator operation, making batteries and renewable generation more important in resilience planning.

Electric vehicle charging infrastructure is becoming another driver of behind-the-meter optimization. Fleet electrification can create large new loads with highly concentrated demand patterns. A depot with electric buses, delivery vans, forklifts, or heavy-duty trucks may require significant electrical upgrades, managed charging, on-site generation, and storage to avoid excessive demand charges or interconnection delays. Energy-as-a-Service models are particularly relevant here because many fleet operators do not want to become energy infrastructure developers. They need reliable charging as an operating service, not merely installed chargers.





# Why Energy-as-a-Service is Emerging Now

Energy-as-a-Service is not a new concept. Energy service companies have long financed efficiency upgrades through performance contracting, and third-party ownership has long been common in the solar industry. What is different now is the convergence of technology maturity, customer demand, capital availability, software capabilities, and grid needs. The customer problem is broader than efficiency, and the provider offering is broader than equipment finance.

The first driver is capital discipline. Many commercial and industrial customers face competing demands for capital. A manufacturer may prefer to invest in production equipment rather than in energy infrastructure. A hospital may prioritize clinical facilities. A logistics company may prioritize fleet assets and automation. Even when an energy project has an attractive lifecycle return, it may be rejected internally because it is not core to the business. Energy as a service addresses this barrier by shifting upfront capital requirements to a third party and converting a capital project into an operating or service payment. This does not make the project free; the provider must recover capital, operations, maintenance, financing costs, and margin. It can, however, make deployment easier for customers whose internal hurdle rates, balance-sheet constraints, or capital allocation processes prevent direct ownership.

The second driver is risk transfer. Behind-the-meter projects involve engineering, procurement, construction, interconnection, permitting, software integration, operations, maintenance, performance monitoring, warranty management, and sometimes market participation. Many customers lack the internal staff to manage these risks. A third-party provider can specialize in managing them. The provider can standardize design, aggregate procurement, manage contractors, monitor assets, update software, and optimize performance across a portfolio. The customer receives a contracted outcome, such as lower energy costs, resilience, renewable energy supply, charging availability, or emissions reduction.

The third driver is complexity. The value of distributed energy resources increasingly depends on dispatch decisions. Solar generation, building load, battery cycling, tariffs, weather, demand response events, wholesale prices, distribution constraints, and carbon signals can shift by the hour or even the minute. A traditional engineering project may deliver an asset. An Energy-as-a-Service provider delivers ongoing operational intelligence. This is especially important when value stacking is required. A battery may need to preserve state of charge for resilience, reduce monthly demand peaks, respond to utility events, and avoid excessive degradation. These objectives can conflict. The provider's control platform and operating protocols become central to the business model.

The fourth driver is resilience. Extreme weather, wildfire risk, hurricanes, winter storms, heat waves, aging distribution infrastructure, and cyber risk have heightened the value of continuity. For some customers, outage costs are no longer an occasional inconvenience; they are a board-level risk. Energy-as-a-Service models enable customers to pursue resilience without establishing a full internal power engineering function. The provider can design a microgrid or hybrid system tailored to critical loads, outage-duration targets, fuel logistics, black-start capability, and operating procedures.

The fifth driver is decarbonization. Many corporations have emissions-reduction targets, renewable energy procurement goals, or customer-driven sustainability obligations. Utility-scale renewable procurement remains important, but it does not address every site-level issue. Behind-the-meter solar, storage, efficiency, electrification, and load flexibility can reduce operational emissions and demonstrate visible progress. Global examples are relevant here. In Europe, building efficiency directives and energy performance contracting have helped frame energy upgrades as service-based investments. Internationally, agencies such as IRENA have treated Energy-as-a-Service as an innovation model that can support distributed resources, customer flexibility, and cleaner energy systems. The U.S. market has its own regulatory structure, but the underlying customer logic is increasingly global.



Energy-as-a-Service is growing because businesses want to avoid upfront costs, reduce risk, and handle complex energy systems more easily. At the same time, rising needs for reliability and decarbonization make a service-based energy model more practical than owning and managing assets.

# Business Models and Contract Structures

Energy-as-a-Service is best understood as a family of contract structures rather than a single product. At one end are familiar solar power purchase agreements, in which a provider owns and operates a solar system and sells its output to the host customer. At the other end are full-service microgrid agreements, in which the provider designs, finances, builds, owns, operates, and maintains a multi-asset system under a long-term contract. Between those poles lie efficiency-as-a-service, storage-as-a-service, charging-as-a-service, resilience-as-a-service, and managed energy services.

The key distinction is ownership and responsibility. In a direct ownership model, the customer purchases the assets and assumes performance risk. In a conventional engineering, procurement, and construction model, the customer pays a contractor to build the project and then owns the asset. In an Energy-as-a-Service model, the provider typically retains ownership or operational responsibility and is paid through a service charge, energy payment, availability payment, shared savings arrangement, or a hybrid structure. The contract may include guarantees for price, performance, uptime, savings, emissions, or resilience. The provider's ability to manage risk depends on carefully defining baseline conditions, customer operating behavior, tariff assumptions, force majeure events, maintenance access, and changes in law.

Distributed energy business models are evolving around the idea that value comes from multiple channels. A provider may monetize customer payments, tax credits, renewable attributes, demand response revenue, capacity market participation, ancillary services, utility program incentives, and avoided infrastructure costs. The more revenue streams available, the more attractive the project may be. Yet value stacking also increases contractual complexity. The customer and provider must decide who controls dispatch, who receives market revenue, how battery degradation is allocated, how resilience reserves are maintained, how emissions attributes are counted, and how utility or market rule changes are handled.

Performance guarantees are important but must be realistic. Energy savings depend on weather, occupancy, production schedules, tariff changes, and customer behavior. Solar output depends on irradiance, equipment performance, soiling, shading, and outages. Battery value depends on load shape and tariff structure. Microgrid resilience depends on fuel availability, maintenance, islanding equipment, control systems, and operating procedures. A well-written contract does not pretend these uncertainties do not exist. It allocates them clearly.

The financing structure also matters. Providers with access to low-cost capital can offer more competitive pricing. Tax equity, investment tax credits, depreciation, grants, state incentives, and renewable energy certificates can materially affect project economics. For nonprofit, public-sector, and tax-exempt customers, third-party ownership can be particularly attractive because the provider may be better positioned to monetize tax benefits. This has made Energy-as-a-Service relevant to universities, municipalities, hospitals, transit agencies, airports, and other institutional customers.

# Cost, Resilience, Carbon, and Operational Control

The customer value proposition usually starts with cost, but it rarely ends there. Cost optimization can include reducing energy purchases, managing demand charges, avoiding coincident peaks, shifting consumption to lower-cost periods, limiting exposure to volatile prices, improving power factor, reducing outage-related losses, and avoiding oversized utility service upgrades. In competitive retail markets, a managed behind-the-meter portfolio may also complement supply procurement by shaping the customer's load profile.

Demand charges remain a major driver of many commercial tariffs. A facility may incur a high monthly demand charge from a brief period of peak demand. Batteries and controls can reduce those peaks if they forecast accurately and discharge at the right time. However, demand-charge management is not simple when tariffs include ratchets, coincident-peak charges, seasonal periods, or multiple demand components. Customer energy management systems are valuable because they translate tariff complexity into operating decisions.

Resilience is harder to quantify but often more important. The cost of an outage varies widely by sector. A grocery store may lose inventory. A manufacturer may lose production batches. A data center may breach service obligations. A hospital may face life-safety risks. A port or airport may experience cascading economic effects. Traditional cost-benefit analysis often undervalues resilience because it treats outages as low-probability events rather than as a strategic risk. Energy-as-a-Service contracts can make resilience more actionable by defining critical loads, minimum islanding duration, black-start capability, testing protocols, and service availability.

Carbon management is emerging as another value stream. Behind-the-meter resources can reduce Scope 2 emissions by lowering grid purchases or enabling renewable energy use. Batteries can improve or worsen emissions outcomes depending on when they charge and discharge. A battery charged during high-emissions hours and discharged during low-emissions hours may reduce costs but increase emissions. A more sophisticated optimization system can account for both price and carbon intensity, though this depends on data availability and customer priorities. Over time, carbon-aware dispatch may become a standard feature of commercial energy optimization.

Operational control is often overlooked yet essential. Customers want energy systems that support their business operations, not those that create new burdens. A well-designed Energy-as-a-Service arrangement can provide monitoring, reporting, maintenance, emergency response, regulatory compliance support, and lifecycle asset management. This is especially important for companies with multiple sites. A national retailer, warehouse operator, telecom company, or restaurant chain may need a standardized platform that can be deployed across regions and adapted to local tariffs, utility rules, weather, and facility conditions.

# Market Opportunities for Providers

The market opportunity is broad because the customer base is diverse. Large single-site customers may justify custom microgrids. Multi-site commercial customers may need standardized solar, storage, controls, and analytics across their portfolios. Industrial customers may need power quality, resilience, and process-aware optimization. Public-sector customers may value resilience and predictable budgets. Fleet operators may need charging infrastructure with managed energy costs. Data centers may need rapid deployment, high reliability, and increasingly clean power.

Providers are likely to segment the market by use case rather than by technology alone. Resilience-led projects will differ from demand-charge management projects. Fleet electrification projects will differ from building-efficiency projects. Industrial power-quality projects will differ from retail portfolio optimization. The strongest providers will integrate project finance, engineering, software, regulatory knowledge, and operations.

Utilities also have opportunities, though their role is complicated by regulation and competitive boundaries. Some utilities may offer tariff-based programs, make-ready infrastructure, managed charging, demand response, or non-wires alternatives that use customer-sited resources. Regulated utility ownership of behind-the-meter assets can raise concerns about competition, cost recovery, and cross-subsidization. Unregulated utility affiliates may compete in Energy-as-a-Service markets, but they must navigate affiliate transaction rules and perceptions of preferential access. Utilities that do not provide these services directly may still benefit by enabling them through tariffs, interconnection reform, data access, and distribution planning.

Technology companies, equipment manufacturers, energy service companies, solar developers, storage integrators, retail energy suppliers, private equity-backed platforms, and infrastructure funds are all positioned to participate. Third-party market estimates also indicate that the Energy-as-a-Service opportunity is moving from a niche offering toward a sizable service market. Guidehouse Insights estimated that the global market could grow from approximately \$15.5 billion in 2023 to nearly \$154.9 billion by 2033. The market is attractive for its recurring revenue and long-term customer relationships. It is also challenging because each project sits at the intersection of physical infrastructure, customer operations, utility regulations, and financial engineering. Scale will favor providers that can standardize offerings without overlooking site-specific realities.



# Regulatory Barriers and Policy Friction

The greatest barriers to behind-the-meter optimization are not always technical. They are often regulatory, procedural, and economic. Retail rate design is the first barrier. Customers respond to the prices they face. If rates do not reflect system costs, customer optimization may not align with grid needs. A demand charge based on a customer's individual monthly peak may encourage batteries to reduce site peaks but not necessarily system peaks. A time-of-use rate with outdated peak periods may send the wrong operational signal. Flat volumetric rates may under-reward flexibility. Standby charges can discourage self-generation or microgrids if not designed carefully. Export compensation rules can determine whether solar-plus-storage is attractive or marginal.

Interconnection is the second barrier. Behind-the-meter projects that export power, island, operate in parallel with the grid, or include storage often face complex review. Utilities must ensure safety and reliability, but slow, opaque, or inconsistent procedures can undermine project economics. Technical standards such as IEEE 1547-2018 provide a framework for interconnection and interoperability, yet adoption and implementation vary. Storage adds complexity because it can operate as load, generation, or both. A battery configured for non-export may be reviewed differently from one that can export. A microgrid may require protection studies, transfer trip schemes, control validation, and operating agreements.

Wholesale market access is the third barrier. FERC Order No. 2222 created a pathway for distributed energy resource aggregations to participate in organized wholesale markets, but it should not be read as evidence that broad, uniform DER market access already exists across every RTO or ISO. The concept is straightforward: small resources that cannot individually meet market requirements can aggregate to participate as a larger resource. The implementation is not straightforward. DER aggregations must be registered,



metered, modeled, dispatched, settled, and coordinated with distribution utilities and state regulators. The same asset may be subject to retail tariffs, distribution operating constraints, customer service obligations, and wholesale market rules. Double counting must be avoided. Distribution utilities need visibility into aggregations that may affect local reliability. Customers and aggregators need clear rules that support investment.

State jurisdiction is the fourth barrier. Electricity regulation in the United States is divided among federal, state, regional, and local authorities. Wholesale market participation is federally regulated, while retail rates, distribution interconnection, utility programs, and many customer protections are regulated at the state level. Local permitting and fire codes also matter, particularly for batteries and microgrids. This layering of jurisdictions is not inherently bad; it reflects the industry's structure. But it creates friction for providers seeking to scale standardized offerings across multiple states and utility territories.

Data access is the fifth barrier. Optimization requires interval usage data, tariff data, demand and outage histories, equipment performance data, and sometimes feeder-level or grid-constraint information. Customers often struggle to obtain clean, timely, machine-readable data. Providers may need customer authorization to access utility data, and utilities may have legitimate cybersecurity and privacy concerns. Without practical data access, commercial energy optimization becomes more costly and less accurate.

Cybersecurity and operational coordination are increasingly important. As more behind-the-meter assets are remotely controlled, they become part of the electric system's digital attack surface. A single customer battery is unlikely to threaten the bulk power system. However, a large aggregation of controllable batteries, chargers, generators, and building loads could have broader implications if poorly secured or maliciously controlled. NERC and other industry bodies have identified DER visibility, modeling, and aggregator coordination as emerging reliability issues. Energy-as-a-Service providers will need cybersecurity practices that match the operational importance of the assets they control.



# Implications for Utilities

For utilities, the rise of behind-the-meter optimization is both a challenge and a resource opportunity. The challenge is that customers are taking greater control over load, generation, storage, and resilience. This can reduce sales, alter load shapes, complicate forecasting, and create new operational conditions on distribution circuits. Traditional utility planning assumed customers consumed electricity in relatively predictable patterns. Behind-the-meter resources make net load more dynamic. A feeder with high solar production may experience midday backfeed. A fleet-charging depot may create a new evening peak. A battery fleet may respond to price signals in ways that create secondary peaks if many systems behave similarly.

The opportunity is that customer-sited resources can help solve utility problems. They can reduce local peaks, defer transformer or feeder upgrades, provide demand response, support voltage management, reduce congestion, and improve resilience. Non-wires alternatives rely on this logic. Rather than building traditional infrastructure for every local constraint, a utility may procure targeted load reduction, storage dispatch, or distributed generation. This requires utilities to identify locational needs, compensate for performance, and treat third-party or customer-owned assets as planning resources.

The utility business model is the underlying issue. If utility earnings depend primarily on capital investment in the rate base, utilities may have weak incentives to rely on third-party behind-the-meter resources that defer infrastructure investment. Performance-based regulation, shared savings mechanisms, distribution system planning reforms, and targeted procurement can improve alignment. The goal should not be to force utilities out of infrastructure investment. The grid still needs substantial investment. The goal should be to compare wires and non-wires solutions fairly and select the portfolio that provides reliable service at a reasonable cost.

Utilities also need better visibility. Distributed energy resource management systems, advanced distribution management systems, smart meters, hosting capacity analysis, and interconnection databases are becoming essential. The utility does not need to control every customer asset, but it does need sufficient information to plan and operate safely. The boundary between customer autonomy and grid coordination will be a defining issue of the next decade.





# Implications for Grid Operators and Wholesale Markets

Regional grid operators are primarily concerned with reliability, market efficiency, and resource adequacy. Behind-the-meter resources affect all three. When DERs reduce load during peak periods, they can reduce capacity needs. When they respond to prices, they can improve market efficiency. When aggregated, they may provide energy, capacity, reserves, or other ancillary services. Virtual power plants are the market-facing expression of this opportunity. A portfolio of customer-sited batteries, solar, controllable loads, and generators can be operated as a dispatchable resource if market rules and telemetry support it.

However, grid operators need confidence that aggregated resources will perform. Measurement and verification are central. Baselines for demand response can be controversial. Batteries are easier to meter than load reductions, but their availability depends on state of charge, customer needs, and distribution constraints. Aggregations spanning multiple distribution utilities may face different local operating limits. A dispatch instruction from a wholesale market must not create a distribution reliability problem. This is why coordination among aggregators, distribution utilities, state regulators, and RTOs or ISOs is essential.

Resource adequacy accreditation is another issue. A behind-the-meter resource should receive capacity value only to the extent it can reliably perform during periods of system need. Solar output may be limited during evening peaks. Batteries may have duration limits. Load flexibility may depend on customer operations. Aggregated portfolios can reduce variability, but they still require rigorous performance rules. Over-crediting DERs would create reliability risk. Under-crediting them would discourage useful resources.

The broader market implication is that the distinction between load and resource is eroding. A commercial building can be both a consumer and a flexible resource. A fleet depot can serve as both a new load and dispatchable storage. A factory can be both a reliability-sensitive customer and a demand-response provider. Wholesale markets built around central generators and passive load must evolve to accommodate this reality without compromising reliability.

# Global Examples & Lessons

**Europe's experience shows that standardized contracts, strong policies (like the Energy Performance of Buildings Directive (recast 2024)), and clear measurement frameworks help scale Energy-as-a-Service projects effectively.**



**While the model is flexible and globally relevant, its success depends on strong institutions, reliable payments, and clear regulations—without these, it struggles despite its potential.**

Although the U.S. is the primary focus, global experience offers valuable lessons. In Europe, energy performance contracting has long financed efficiency upgrades, particularly in public buildings. The European policy environment has emphasized building performance, emissions reduction, and renovation, including the 2024 recast Energy Performance of Buildings Directive, which reinforced the EU's policy focus on building performance and renovation. The European experience shows that contractual standardization, measurement and verification, and public-sector procurement frameworks can help scale projects.

International renewable energy organizations have also positioned Energy-as-a-Service as part of a broader transition to flexible, digital, distributed energy systems. This is relevant to both emerging markets and mature power systems. In some markets, Energy-as-a-Service can help customers bypass unreliable grids or avoid upfront capital costs for clean energy systems. In others, it can support grid flexibility and defer network investment. The underlying model is adaptable: customers pay for outcomes, providers manage assets, and digital platforms coordinate performance.

Global examples also offer a caution. Service models depend on institutional trust, enforceable contracts, reliable payments, technical standards, and regulatory clarity. Where these foundations are weak, Energy-as-a-Service can struggle. The U.S. has strong capital markets and sophisticated providers, but its regulation is fragmented. Europe has strong policy drivers but varied national implementation. Emerging markets may have strong resilience needs but higher financing risk. The model is powerful, but it is not self-executing.

# Strategic Considerations for Commercial and Industrial Customers

Commercial and industrial customers should treat behind-the-meter optimization as a strategic procurement and risk-management exercise, not merely a technology purchase. The first question is not whether to buy solar, batteries, or controls. It is what problem the customer is trying to solve. A cost-reduction, resilience, decarbonization, or fleet-electrification project may require different designs, even if they use similar technologies.

Customers should begin with load analysis, tariff review, outage-cost assessment, facility constraints, emissions objectives, and capital planning. They should identify critical loads, operational flexibility, roof or land availability, electrical infrastructure limits, and projected load growth. They should also assess whether direct ownership or Energy-as-a-Service better aligns with their financial and operational objectives. Direct ownership may offer greater control and long-term upside, while Energy-as-a-Service may offer speed, risk transfer, and operational expertise.

Contract discipline is essential. Customers should understand their payment obligations, escalation clauses, performance guarantees, savings calculations, asset ownership, buyout rights, termination rights, change-in-law provisions, maintenance responsibilities, data rights, cybersecurity requirements, insurance, resilience testing, and end-of-term treatment. They should also clarify who receives renewable energy certificates, tax benefits, demand response payments, capacity revenues, and other market revenues.

Customers with multiple sites should avoid one-off decision-making whenever possible. Portfolio strategy can improve procurement leverage, standardize data, reduce transaction costs, and support enterprise-level reporting. However, standardization should not overlook local utility rules. A project that works in California may not work in Indiana, Texas, New York, or Georgia under the same assumptions. Tariffs, incentives, interconnection rules, climate, facility load shapes, and market access vary materially.



**Define the Goal First:** Focus on the problem (cost, resilience, emissions) before choosing technology.

**Manage Risk and Scale Smartly:** Understand contracts and use a portfolio approach, while adapting to local rules.

# Strategic Considerations for Providers

Providers must be clear about the distinction between selling equipment and delivering outcomes. Energy-as-a-Service requires long-term accountability. Providers that overpromise savings, underprice operational risk, or rely on uncertain market revenues may face customer disputes and financial underperformance. The strongest providers will have disciplined underwriting, conservative baseline methods, robust controls, and transparent reporting.

Scale will require standardization, not commoditization. Providers need repeatable contract templates, engineering designs, software platforms, financing structures, and operating procedures. At the same time, they must adapt to customer operations and utility territory rules. This balance is difficult. Excessive customization erodes margins. Excessive standardization creates performance risk.



Partnerships will remain important. Few providers can do everything internally. Project finance, tax equity, equipment supply, software, engineering, construction, operations, market aggregation, and utility coordination may require different capabilities. The provider that owns the customer relationship must still manage the full delivery chain. From the customer's perspective, Energy-as-a-Service is attractive because it reduces fragmentation. A provider that merely passes complexity back to the customer undermines the model.

Providers should also prepare for increased scrutiny. As behind-the-meter assets become more important to grid operations, regulators and utilities will demand better data, stronger cybersecurity, performance verification, and operational coordination. Providers that build these capabilities early will have an advantage.



# The Road Ahead

Behind-the-meter optimization is likely to become a standard feature of commercial and industrial energy strategies. The direction is clear, even though the pace will vary by region and customer segment. U.S. electricity demand is growing again: EIA's 2026 outlook projects the strongest four-year growth in U.S. electricity demand since 2000, driven in part by data centers. Reuters reported EIA projections that U.S. power consumption would rise from a record 4,195 billion kWh in 2025 to 4,268 billion kWh in 2026 and 4,372 billion kWh in 2027. Grid interconnection and transmission constraints are increasingly evident. Extreme weather is raising the value of resilience. Corporate customers continue to pursue sustainability goals, though the language and emphasis may vary by industry and political environment. Technology costs, software capabilities, and financing structures continue to improve.

Energy-as-a-Service is likely to grow because it addresses a practical market gap. Many customers need better energy systems but do not want to own, finance, operate, or optimize them directly. Third-party providers can fill that gap. The model is especially well suited to customers with high energy intensity, high outage costs, limited capital, multi-site portfolios, fleet electrification needs, or strong decarbonization commitments.

The decisive issue will be integration. Customer-side integration is needed so that solar, storage, controls, generation, charging, and building systems operate as a coordinated platform. Utility integration is needed so that behind-the-meter resources support rather than undermine distribution planning. Market integration is needed so that aggregated resources can provide reliable services to wholesale markets. Regulatory integration is needed so that retail tariffs, interconnection rules, data access, and wholesale participation do not work at cross-purposes.

The industry should resist two simplistic conclusions. The first is that behind-the-meter resources are a threat to utilities and should be slowed. That view overlooks their potential value for peak reduction, resilience, customer choice, and infrastructure deferral. The second is that distributed resources can replace conventional grid planning and central infrastructure. That view overlooks the operational discipline required to maintain reliability. The more practical conclusion is that behind-the-meter optimization and Energy-as-a-Service are becoming part of the modern grid toolkit. They must be planned, priced, operated, and regulated accordingly.



# Conclusion

Behind-the-meter optimization marks a structural shift in how commercial and industrial customers use electricity. The customer is no longer merely a meter at the edge of the distribution system. The customer site is becoming a controllable energy platform with generation, storage, flexible load, software, and operational intelligence. This shift is driven by cost pressures, resilience needs, decarbonization goals, electrification, and the growing complexity of electricity markets and tariffs.

Energy-as-a-Service is rising because it turns that complexity into a managed offering. It allows customers to pursue behind-the-meter energy solutions without assuming all the capital, technical, and operational burdens. It gives providers an opportunity to build long-term distributed energy business models focused on financing, integration, optimization, and performance. It also gives utilities and grid operators a potential source of flexibility at a time when the grid needs more controllable capacity and better use of existing infrastructure.

The model will not succeed on rhetoric alone. It requires disciplined contracting, credible measurement, sound engineering, cybersecurity, transparent economics, workable interconnection, and regulatory frameworks that recognize both customer and system value. The winners will be customers who clearly define their objectives, providers who deliver measurable outcomes, utilities that learn to harness customer-sited flexibility, and regulators who modernize rules without sacrificing reliability or fairness.

The rise of energy as a service is therefore not merely a financing trend. It is part of a broader reorganization of the electric power sector around distributed assets, digital control, customer choice, and operational flexibility. For commercial and industrial customers, the opportunity is to transform energy from a recurring expense into a managed strategic capability. For utilities and grid operators, the challenge is to integrate that capability into planning and operations. For the industry as a whole, the task is to build a market structure in which behind-the-meter optimization strengthens the grid rather than simply bypassing it.

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