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POWER POINTS

BEYOND TRANSACTIONS:
HOW UTILITIES ARE RETHINKING INFRASTRUCTURE, ENGAGEMENT AND THE CUSTOMER RELATIONSHIP

ELISABETH MONAGHAN
Editor in Chief

It is impossible to work in the electric energy sector without recognizing that rapid, ongoing change is constant. One thing, however, remains unchanged: electricity demand will only increase.

While new technology and innovations evolve, grid modernization remains a priority for the utility sector. In this issue, our contributors provide updates on what they are doing to advance grid modernization, why they chose the approaches they've taken and what lessons they can offer the rest of us.

There are a couple of articles I'm highlighting in this column because they capture some of the latest trends shaping the industry's direction: the first examines how utilities can collaborate to modernize the grid more efficiently, and the second explores the shift from transactional interactions to personalized, relationship-based engagement. Both reflect a broader truth: change is a given, and the industry is rethinking not just what it builds, but how it learns, plans and establishes trust.

From isolated pilots to shared discipline

One example of this rethinking can be seen in how utilities are approaching grid modernization. In her article, "The Grid Will Not Modernize Itself: Why AEIC's Grid Advancement Program Is Becoming a Movement," Dr. Elizabeth Cook examines how utilities are changing the way they organize themselves to innovate, working to avoid solving the same problems independently, at great cost and with inconsistent results. The AEIC Grid Advancement Program is a structured, utility-led initiative built on a straightforward idea: no utility should have to navigate grid modernization alone.

Cook describes a challenge facing utilities across the industry. The pressures are converging all at once. We have AI-driven data center load, electrification, distributed energy resources, aging infrastructure and climate volatility, all unfolding at a pace the industry has never experienced before.

What makes the AEIC program distinctive is that it targets not just the grid, but also the process of modernizing it. Traditional planning was built for a steadier future, where load growth was predictable and capital projects could unfold over long horizons. That model will still be part of the answer, but it cannot be the only answer. The grid of the future demands a broader portfolio: physical infrastructure alongside software, data, automation and customer-side flexibility, evaluated together rather than in sequence.

The AEIC program also addresses a problem that is less visible but just as consequential: promising ideas getting stuck between interest and execution. Without a repeatable evaluation process, the same questions, who owns the problem, what does success look like and what cybersecurity review is required, get answered differently by every team, at every utility, over and over again. The AEIC model standardizes that journey, giving utilities a common workflow to move from idea to peer-reviewed pilot faster and with lower risk.

Across nearly every modernization use case, the same challenge emerges: data gaps identified too late can slow progress or halt a pilot altogether. The AEIC playbooks help surface those issues early, enabling utilities to address them before significant time and resources are invested.

From transactions to relationships

While utilities are rethinking how they modernize infrastructure, they are also rethinking how they engage the people who depend on it. One of the clearest explanations of this shift from transactions to relationships comes from Stefan Zschiegner of Itron. In his article, "From Service Provider to Energy Advisor: Redefining Utility Engagement," Zschiegner describes how the relationship between energy providers and their customers has fundamentally changed.

As Zschiegner writes, "For much of their history, utilities have interacted with customers primarily through bills, service notices and periodic program communications. These touchpoints reflected a grid in which energy flows were predictable, pricing structures were largely static and customer behavior had little immediate impact on system operations. Engagement served a transactional purpose: communicate usage, collect payment and resolve issues when they arose."

Distributed energy resources, electric vehicles, rising electricity costs and increasingly volatile demand patterns are reshaping that relationship. Customers have evolved from passive rate-paying consumers to active prosumers whose decisions can directly influence grid reliability and performance.

To meet those growing expectations, Zschiegner argues that utilities must communicate at moments when guidance can still influence outcomes, rather than explain results after the fact. That requires moving from generalized messaging to personalized, behavior-based engagement grounded in high-quality data. When recommendations reflect actual usage patterns and are delivered before costs are incurred, customers are more likely to act on them and trust the source.

Grid-edge intelligence plays a central role in enabling real-time engagement. By processing and analyzing data closer to where energy is consumed, utilities can identify consumption trends, detect anomalies and assess how customer behavior affects grid performance in near real time.

The value of that real-time visibility increases when it is paired with artificial intelligence. By analyzing historical usage alongside factors such as weather and regional demand conditions, AI enables utilities to anticipate issues and deliver forward-looking guidance rather than reactive alerts, with recommendations that improve as customer behavior evolves.

Zschiegner's broader point is that utilities willing to make this shift will strengthen customer relationships, improve grid reliability and position themselves as trusted energy advisors rather than billing entities.

Together, these two trends point in the same direction. The industry is not just deploying new technology. It is rethinking how utilities learn, plan, collaborate and build trust – with customers, with peers and with the grid itself.

If you would like to contribute an article on an interesting project, please email me:

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Elisabeth

THE GRID TRANSFORMATION FORUM

THE GRID WILL NOT MODERNIZE ITSELF:

WHY AEIC'S GRID ADVANCEMENT PROGRAM IS BECOMING A MOVEMENT

ELIZABETH COOK, PH.D., AEIC

The electric grid is one of the greatest engineering achievements in modern history. It powers nearly every part of daily life: hospitals, homes, factories, transportation systems, communications networks, water systems, data centers and the digital economy. It is so essential, and often so reliable, that most people rarely think about it until the power goes out.

But the grid was not designed for the world now arriving at its doorstep.

Across the country, utilities are being asked to connect new loads faster, integrate distributed energy resources, harden aging infrastructure, prepare for more extreme weather, manage affordability pressure, address supply chain constraints and modernize planning processes built for a slower, more predictable era. AI-driven data center load, electrification, distributed energy resources and climate volatility are converging at once, on a clock that no prior grid transition has had to keep. The system is being asked to become more dynamic, more resilient, more digital and more flexible, while still delivering the reliability customers depend on every hour of every day.

This is the defining engineering and operational challenge of our era, and utilities are being asked to solve it on a faster clock than at any point in the system's history.

That is why the AEIC Grid Advancement Program, powered by InnovationForce, exists.

The program is built on a simple but powerful idea: no utility should have to solve the grid modernization challenge alone. The technologies to address many of today's problems already exist. The harder work is knowing which solutions fit which operational problems, how to evaluate them in real utility environments, how to learn from peers who may already be testing similar approaches and how to move from promising idea to practical deployment with greater speed and lower risk.

The AEIC Grid Advancement Program is designed to close that gap.

AEIC's origin story

AEIC is uniquely positioned to lead this work because of who it is and where it comes from. As the electric utility industry's longest-serving association, AEIC was founded in 1885 by the pioneering electric companies that helped build the modern electric power system, and it has been in the room for every major transition the grid has had to navigate since: industrial electrification, the interconnection era, the long arc of reliability engineering, the nuclear build-out, distributed generation, smart metering, and now, the data layer. Its roots are not in abstract theory. They are in practical utility operations, in shared engineering knowledge and in the hard work of keeping the power system running.

That origin story still matters.

AEIC brings together operational utility leaders and subject-matter experts, the people closest to the day-to-day realities of generation, transmission, distribution, reliability, resilience, planning and modernization. These are the leaders who understand that every new idea must eventually survive real constraints: budgets, regulation, safety, cybersecurity, workforce readiness, system integration, procurement, customer impacts and reliability obligations.

That is what makes AEIC different. It is not a forum built around innovation theater. It is a trusted, utility-led community focused on operational excellence and practical execution, the kind of peer-to-peer structure complex systems require when order and chaos are present at the same time. The industry has been here before, and collaboration is what carried it through every previous transformation.

Its motto, "Knowledge of one is the knowledge of all," has never been more relevant.

The grid is changing too quickly for every utility to independently evaluate every technology, build every use case and learn every lesson from scratch. One utility may already have tested a wildfire situational awareness tool. Another may have worked through the data architecture needed for feeder-level load forecasting. Another may be piloting a non-wires alternative to address a capacity constraint. Another may have learned difficult lessons about cybersecurity review, vendor integration or operations.

If those lessons stay isolated, the industry moves slowly. If they are shared through a trusted, structured process, the industry can move faster.

Why this program matters now

The AEIC Grid Advancement Program begins with a clear view of the pressures utilities are facing. Utilities are not only paying for aging infrastructure. They are also meeting today's reliability and resilience expectations while preparing for tomorrow's digital, distributed and flexible grid. AEIC's program materials describe this as a "trifecta" of cost pressures: yesterday's deferred investments, today's reliability and climate resilience needs and tomorrow's required technologies and capabilities. These forces are placing pressure on utility budgets, customers, regulators and traditional planning frameworks.

The issue is not only physical infrastructure. It is also how utilities plan, partner, regulate and learn.

Traditional planning processes were built for a steadier future, where load growth was more predictable and infrastructure projects could be planned over long horizons. But the future now emerging is more dynamic. Load growth from data centers, electrification, electric vehicles, distributed energy resources and new industrial demand is more localized, more variable and harder to forecast. The old playbook (study, plan, build, recover costs over decades) will still be part of the answer, but it cannot be the only answer.

The future grid will require more options, better data, new operating models, new forecasting and automation and new ways to evaluate solutions that do not always look like traditional capital projects.

That is where the Grid Advancement Collaborative Program becomes essential. It gives utilities a way to modernize not only the grid, but also the process of modernization itself.

InnovationWorks as the program engine

One of the most important features of the program is that it standardizes the journey from idea to action.

That may sound simple, but it is one of the biggest unlocks for utility innovation. Inside utilities, promising ideas often stall because every team evaluates them differently. A solution may be discussed at a conference, introduced by a technology partner, raised by an internal champion, or mentioned by a peer utility. But without a repeatable process, the idea can get stuck between interest and execution.

Who owns the problem? What does success look like? What data and systems does it touch? What cybersecurity review is required? What would make a pilot worth scaling?

The AEIC Grid Advancement Program turns those questions into a structured workflow.

Through challenge-specific playbooks and InnovationWorks workflows, AEIC members can move through a common process: define the Big Idea, frame the challenge statement, compare business-as-usual approaches, explore modernization solution stacks, identify potential solution providers, evaluate data and cybersecurity needs, create a test plan, gather peer feedback and prepare for a more credible pilot.

This is how the program helps members go faster with lower risk.

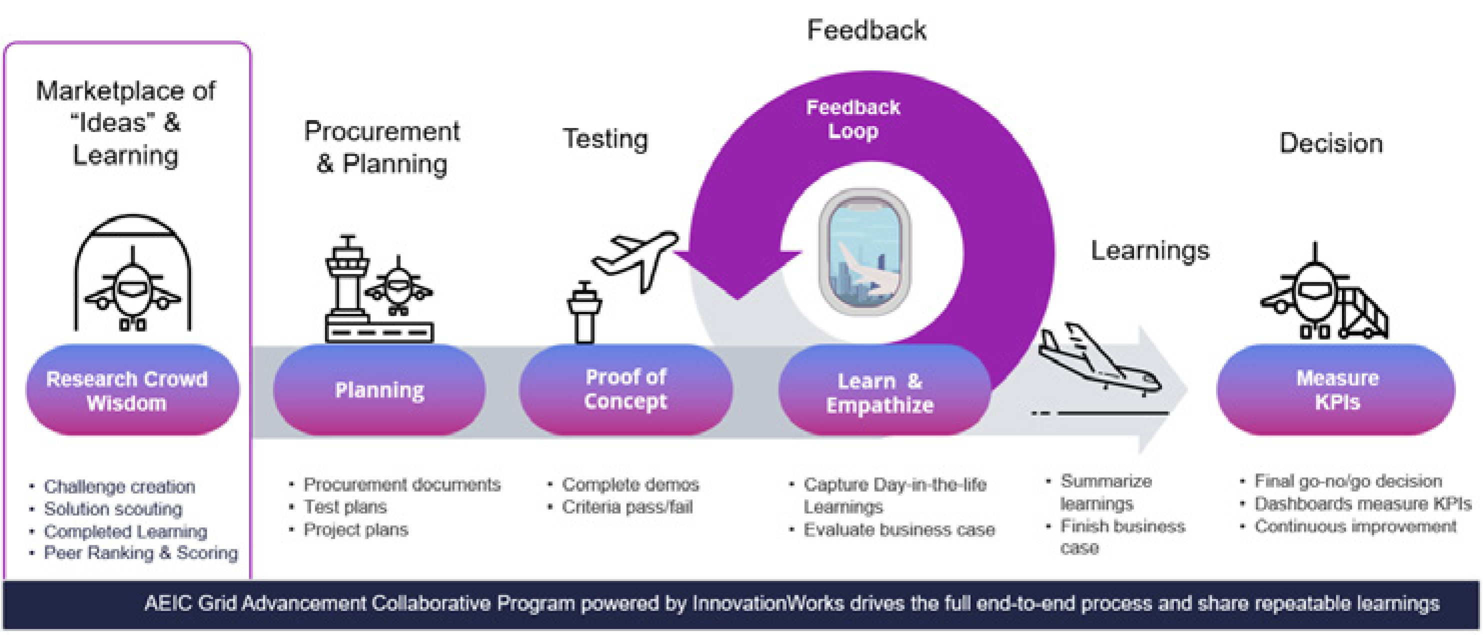
It does not ask utilities to move recklessly. It helps them move with discipline. It reduces the time spent reinventing the same evaluation process. It gives teams a common language. It helps peers consistently review use cases. It creates a stronger record of why an idea is worth testing, what it is expected to prove and what conditions must be in place before it can scale.

That repeatability is critical if the industry wants to move beyond isolated pilots and toward scalable modernization.

InnovationWorks, powered by InnovationForce, serves as the collaboration and workflow engine for the AEIC Grid Advancement Program. It gives AEIC members a private, structured workspace to turn shared grid modernization challenges into actionable use cases, peer-reviewed pilots and scalable learning.

That matters because utility innovation is not just about finding new technologies. It is about organizing the work required to evaluate them. A promising solution still has to clear the same bar: real data, real systems, real cybersecurity review and real operational. Ownership.

InnovationWorks helps standardize that journey and helps reduce duplicated effort. By organizing challenges around modernization solution stacks and connecting them to viable solution providers, InnovationWorks gives utilities a stronger starting point for due diligence. Members still evaluate fit, risk, cost, integration and operational readiness, but they can do so with more structure, more context and more peer insight.



An approach backed by research

One of the most valuable aspects of the AEIC Grid Advancement Program is that it treats innovation as a discipline, not a slogan.

Utilities are not short on ideas. The harder problem is creating the conditions for those ideas to be tested, challenged, adopted and scaled across complex operating environments. That is where InnovationForce adds distinctive value.

InnovationForce brings a research-informed approach through the work of its co-founder, Dr. Linda A. Hill of Harvard Business School. Her recent book, "Genius at Scale", focuses on how leaders create the conditions for innovation to scale across complex organizations. That is precisely the problem utilities face every time a promising pilot fails to move beyond a single operating area.

Every challenge playbook starts with a modernization solution stack

A defining feature of the program is its use of challenge-specific modernization "solution stacks." Each playbook begins by looking honestly at the business-as-usual approach, then broadens the field of possible solutions.

This is important because many utility challenges are currently addressed through familiar tools that remain necessary but may no longer be sufficient on their own. The program does not dismiss traditional infrastructure investment. It reframes it as one part of a broader portfolio.

The pattern repeats across the program's priority challenges. For weather and wildfire resilience, undergrounding and pole hardening sit alongside situational awareness, sensors, predictive analytics and data-driven response. For load forecasting, deterministic models sit alongside probabilistic forecasting, real-time DER visibility and adaptive planning. For capacity constraints, a feeder or substation upgrade sits alongside non-wires alternatives, managed EV charging, virtual power plants and customer flexibility programs. For interconnection, the large transmission build sits alongside advanced reconductoring, dynamic line ratings, flow-control technologies and storage-as-transmission. In none of these areas does the modernization layer replace the traditional approach. It expands the set of viable options.

This solution-stack approach helps utilities ask better questions. Instead of defaulting to, "Which capital project should we build?" teams can ask, "What combination of physical infrastructure, software, data, automation, operational changes and customer-side resources can solve this problem at the right speed, cost and risk level?"

That is a fundamentally more modern way to plan.

Data readiness as a modernization requirement

Another strength of the program is that it treats data readiness as central to grid modernization.

Many new solutions depend on data that may be fragmented across the organization. A forecasting use case may require AMI interval data, SCADA data, GIS models, customer information, DER interconnection records, weather data, EV adoption information and feeder or transformer loading. A resilience use case may require asset data, outage history, weather feeds, vegetation data, field inspection records and operational telemetry. A capacity or flexibility use case may require customer load shapes, program participation data, DER visibility and operational constraints.

These data sources often sit in different systems, owned by different teams, governed by different processes. If those issues are discovered late, pilots slow down or fail. The AEIC playbooks and InnovationWorks workflows encourage teams to identify data needs, governance gaps and cybersecurity considerations early.

That is another way the program lowers risk. It brings hidden implementation issues to the surface before a utility has already committed major resources.

In the modern grid, data is not a side issue. It is part of the infrastructure of decision-making. Utilities that can organize, govern and apply data effectively will be better positioned to forecast load, integrate DERs, evaluate non-wires alternatives, improve resilience and operate a more flexible grid.

A movement led by operators

The AEIC Grid Advancement Program is powerful because it is led by the people who understand the grid best: operational leaders and subject-matter experts responsible for keeping the system safe, reliable, resilient and affordable every day.

That gives the program credibility. It also gives it urgency.

The future grid will not be built by technology alone. It will be built by the operators who know how to translate technology into utility practice, the same people AEIC has put in the same room for more than a century. It will require planners, operators, engineers, IT teams, cybersecurity experts, procurement leaders, customer teams, regulators and solution providers to work in new ways. It will require governed environments to test ideas, shared methods to evaluate them and trusted networks to accelerate learning.

The AEIC Grid Advancement Program provides that space.

It is a deliberate move away from isolated pilots and endless scouting, toward shared discipline that creates lower-risk, higher-impact modernization portfolios more affordably.

The grid modernization challenge is too large for any single utility to solve on its own. Together, utilities can move at the pace this transformation actually demands. That has been the AEIC pattern for 140 years. This program is its current chapter. Learn more about the program, watch the latest videos or download challenge playbooks by visiting the AEIC Center for Operational Excellence **website**.

Dr. Elizabeth Cook is vice president of Technical Strategy at the Association of Edison Illuminating Companies (AEIC) and program director for the Center for Operational Excellence, where she leads AEIC's grid modernization, workforce and AI fluency programs. A national leader in grid modernization and operational transformation, she hosts the Grid Mod Pod, AEIC's weekly podcast where utility voices share with utility voices.

Cook serves on the board of the Energy Systems Integration Group (ESIG), is an adjunct professor at Carnegie Mellon University and was previously director of Advanced Grid Systems at Duquesne Light. She holds a Ph.D. in electrical and computer engineering from the University of Pittsburgh.

Outside her AEIC work, she runs an advisory and leadership coaching practice and is the founder of Integrated Being, where she writes and hosts the Integrated Being podcast on mind-body-spirit connection and intentional living.

GREEN OVATIONS

BEYOND MANUAL SAMPLING:
HOW REAL-TIME TRANSFORMER MONITORING CUTS COSTS WHILE BOOSTING GRID RELIABILITY

THOMAS JARMAN

Dissolved gas analysis has long been the gold standard for transformer diagnostics. But even the best laboratory results are only as good as the sample behind them. Even worse, time delays often mean critical changes go unnoticed.

When KAMO Power detected acetylene in an 84 MVA transformer for the first time in its operational history, the utility faced a dilemma familiar to grid operators nationwide: How aggressively should the team respond? The fault gas had jumped from 0 to 1.2 ppm in a year, then climbed to 19 ppm over 6 months despite intensive manual sampling.

Each sample required pulling two technicians from regular duties, sending oil to external labs and waiting days for results. Costs mounted quickly, but without real-time data, maintenance managers lacked confidence in their next move. Should they drain the transformer for inspection? Plan for an outage? Keep sampling and hope the trend reverses?

Through this experience, the Oklahoma-based electric cooperative recognized that traditional dissolved gas analysis protocols, while proven over decades, increasingly struggle to meet the operational and financial demands of modern grid management. As transformer populations age, load demands intensify and O&M budgets tighten, utilities need monitoring approaches that deliver actionable insights without escalating costs or exposing personnel to unnecessary risk.

Transformer reliability = grid stability

For utilities and electric cooperatives, transformer reliability is synonymous with grid stability. Forming the critical junction between transmission and distribution, these high-value assets convert power and maintain voltage balance across increasingly complex networks. Yet as demand climbs and many transformers near or exceed their designed service lives, utilities face growing challenges in monitoring health, preventing faults and optimizing maintenance budgets.

When electrical or thermal faults occur within the oil, they generate gases — hydrogen, methane, acetylene and others — that can point to a larger problem. If concerning trends emerge, sampling frequency increases, sometimes dramatically. Yet for most utilities, traditional DGA still means manual sampling and laboratory testing, sometimes performed only once a year.

A low sampling frequency limits visibility into developing faults and inherently introduces delays between sample collection and results, potentially obscuring rapid changes in transformer condition. The process also incurs operational costs — sending technicians to remote sites, managing sample logistics and paying lab fees — all while exposing personnel to field risks.

The hidden costs of manual sampling

KAMO's 2012 Waukesha transformer had logged clean DGA results since its installation. Annual samples from 2016 through 2021 showed no acetylene, a key indicator of arcing in oil. But the July 2022 sample revealed 1.2 ppm of acetylene, where none had been detected before.

Following lab recommendations, KAMO maintenance staff shifted to manual sampling every two weeks. Within a month, two additional samples showed acetylene climbing to 3.7 ppm. The electric cooperative consulted the manufacturer and ran comprehensive field tests: power factor, transformer turns ratio, winding resistance, insulation resistance and oil power factor evaluations. Staff exercised all DETC no-load taps, tested ratios and performed resistance testing on reactor core ground and main core grounds.

The tests returned no abnormalities, yet acetylene continued rising to 4.3 ppm.

The management of this sampling protocol remained burdensome and expensive. More troubling, a clear picture of the situation remained elusive to maintenance managers. Without confidence in the data story, they believed continued manual sampling was the only option.

KAMO's service territory spans parts of four states, requiring two technicians to travel to substation sites for each sample. Those staff hours represented direct costs and opportunity costs from work left undone. Sample collection, shipping, lab analysis and results interpretation added administrative overhead. Perhaps most concerning, repeated site visits increased personnel exposure to potential safety hazards.

Consequently, KAMO sought a way to make its decisions with confidence without sending people into the field every few weeks.

The real-time revolution

The situation crystallized a broader industry trend: While foundational to transformer asset management, manual sampling protocols provide only periodic glimpses into asset health. Between sample measurements, operators essentially operate blindly, unable to correlate fault gas trends with loading conditions, temperature variations, power quality issues or other operational factors that might explain changes in transformer behavior.

In spring 2024, KAMO's maintenance managers decided to deploy a mobile online multi-gas DGA monitor to collect real-time data during the transformer's summer high-load operational periods. The **Vaisala Optimus OPT100 monitor** installation took just a few hours and began providing hourly dissolved gas measurements immediately.

The difference proved revelatory. Rather than waiting weeks between snapshots, operators could observe how acetylene levels responded to loading and thermal conditions in near real time. Patterns that remained hidden in periodic sampling data emerged when viewed continuously. The rate of change, visualized through trending slope data, allowed maintenance managers to evaluate fault severity with new precision.

The Vaisala sensor provided the maintenance team with the confidence to cut back on O&M manual sampling costs while improving and increasing the amount of transformer gassing data.

Summer 2024 data told a story that manual sampling had only hinted at: Despite higher loads during peak season, acetylene levels continued to decline, stabilizing around 6.5 ppm by season's end. The transformer was not experiencing active, progressive faulting. Whatever had caused the initial acetylene generation had resolved, and the unit could safely remain in service.

Equally important, the OPT100's real-time trending enabled KAMO's asset managers to correlate gas behavior with temperature and load patterns, providing context that static lab results could not.

That insight carried enormous value. KAMO avoided planning for backup unit deployment, scheduling an outage during critical summer months and incurring inspection costs that could have run into six figures when factoring in labor, equipment, lost capacity and potential repair expenses if issues had been found.

Building a hybrid monitoring strategy

Armed with confidence from continuous monitoring data, KAMO strategically pivoted. The mobile multi-gas monitor confirmed the transformer's condition had stabilized around 6.5 ppm acetylene. Rather than maintain that level of monitoring indefinitely, the co-op installed a **Vaisala MHT410 moisture, hydrogen and temperature transmitter** for ongoing surveillance.

This approach illustrates a cost-effective transformer asset management alternative. Different situations demand different monitoring intensities. When fault gases appear or trends raise concerns, multi-gas continuous monitoring provides the necessary detailed trending data for confident decision-making. Once situations stabilize, single-gas monitoring focused on key fault indicators offers early warning at a lower cost.

Hydrogen serves as a “smoke detector” gas because it typically appears early when faults begin developing. By monitoring hydrogen continuously, KAMO would receive advance warning if the previous acetylene issue resurged or if new fault conditions emerged. That assurance allowed maintenance managers to reduce manual lab sampling from monthly to twice yearly, seriously cutting both direct costs and staff exposure to risks in the field.

The operational math proved compelling. KAMO estimates it saved tens of thousands of dollars in O&M and testing costs on this single fault case, a figure that accounts for avoided lab fees, reduced technician travel time and the administrative overhead of managing intensive sampling protocols. The co-op also avoided potentially unnecessary repair expenses and capacity loss from an outage that continuous monitoring revealed was unwarranted.

Project stakeholders noted the savings could have multiplied if the mobile monitor had been deployed sooner in the investigation cycle. That lesson has shaped KAMO’s thinking about future transformer health management strategies.

Technical success factors

Several technical factors enabled KAMO’s successful monitoring strategy shift. The online monitors require no consumables and minimal scheduled maintenance, contrasting sharply with some competing technologies that demand regular calibration gas or sensor replacements. Plus, installation speed matters when assessing developing fault conditions. The two-hour deployment timeframe allowed KAMO to quickly collect continuous data without extensive outages or complex integration work.

Remote data accessibility also simplified the monitoring program. Rather than requiring site visits to download data or check readings, maintenance managers could access measurement information from office locations, reviewing trends and setting alerts without field trips. As utility workforces face skilled labor shortages and competing demands on technical staff time, remote monitoring becomes increasingly valuable.

Hourly measurements throughout the summer load period created a detailed picture of how the transformer responded to varying conditions. The monitoring systems’ granularity enabled correlation analysis between fault gas levels, loading patterns and thermal conditions that would be impossible with periodic manual sampling.

For utilities evaluating monitoring technology options, these operational characteristics deserve weight alongside accuracy specifications and measurement ranges. A highly precise monitor that requires frequent maintenance visits, consumes expensive calibration gases or demands complex data retrieval may deliver less practical value than a lower-maintenance system providing adequate precision for decision-making.

Scaling monitoring across the fleet

KAMO’s experience with the Waukesha transformer prompted broader strategic thinking about its fleetwide monitoring approaches. The electric co-op is now investigating how to integrate fixed DGA monitors and portable units into standard maintenance and asset health operations across its transformer population.

The KAMO case’s evolution reflects a maturing understanding of monitoring economics. Not every transformer justifies permanent multi-gas monitoring, particularly newer units with clean DGA histories and lower criticality to grid operations. But having mobile multi-gas monitors available for deployment when concerning trends emerge provides flexibility that pure manual sampling cannot match.

Capital for monitoring infrastructure is limited, but so is tolerance for unexpected transformer failures. By mixing monitoring technologies and deployment models, operators can enhance visibility into asset health without budget-breaking capital expenditures.

Data-driven resilience

The pressures driving KAMO's monitoring strategy evolution affect utilities and electric co-ops nationwide, regardless of size or business model.

The transformer population is aging across the industry. Many units installed during major grid expansion periods in the 1960s through 1980s are reaching or exceeding design life. These aging assets face increasing failure risk just as load growth from data centers and electrification stresses grid infrastructure, creating heightened urgency around asset health visibility.

And with regulatory and stakeholder expectations around grid reliability rising, customers and regulators increasingly expect utilities to prevent failures rather than simply respond to them.

With the electric utility industry standing at an inflection point in transformer asset management, online monitoring technologies have matured to offer practical alternatives that can enhance visibility while controlling costs.

KAMO Electric Cooperative's experience demonstrates that the path forward is not about abandoning proven manual sampling protocols but rather about deploying multiple monitoring tools strategically. Mobile multi-gas monitors for intensive investigation periods, permanent single-gas systems for ongoing surveillance and periodic manual sampling for baseline monitoring can work together in a hybrid approach that optimizes resource allocation.

For an industry facing mounting pressures on multiple fronts, KAMO's journey from reactive manual sampling to proactive hybrid monitoring offers a roadmap. And the destination is a flexible, scalable approach that deploys the right monitoring intensity in the right situations. In that balance lies the future of transformer asset health management: better data, lower costs, improved safety and the confidence to make critical decisions that keep the grid running reliably.

Thomas Jarman is a sales manager and power and utility industry expert. He has worked with a range of product lines for environmental monitoring, dissolved gas analysis and moisture in oil, as well as cloud-based data connectivity. Prior to joining Vaisala, Jarman worked for a wastewater treatment manufacturing company and an EHS consulting firm. At the University of Colorado, he studied atmospheric and oceanic sciences.

FROM SERVICE PROVIDER TO ENERGY ADVISOR: REDEFINING UTILITY ENGAGEMENT

STEFAN ZSCHIEGNER

For much of their history, utilities have interacted with customers primarily through bills, service notices and periodic program communications. These touchpoints reflected a grid in which energy flows were predictable, pricing structures were largely static, and customer behavior had little immediate impact on system operations. Engagement served a transactional purpose: to communicate usage, collect payment and resolve issues when they arose.

That model no longer reflects today's operating reality. As demand patterns become more volatile, energy costs rise and distributed energy resources proliferate at the grid edge, customer behavior increasingly influences grid performance and reliability. Utilities are now being asked to engage customers not only as ratepayers, but as active participants whose decisions affect outcomes across the system. Meeting this shift requires more than faster communication or additional digital channels. It requires a fundamental evolution in how utilities leverage data to guide action—moving from explaining what already happened to influencing what happens next.

This transformation depends on turning information into insight at the moment decisions are made. Data is the foundation, but data alone does not create value. Utilities must convert raw information into timely, contextual guidance that helps customers take meaningful action while supporting broader operational goals.

The end of transactional engagement

The utility-customer relationship has traditionally been centered on monthly billing, but these infrequent interactions create a delayed feedback loop that limits the usefulness of information.

Customers learn about their energy consumption only after it has occurred and are left reacting to a balance due rather than understanding how daily choices shaped the outcome. This approach limits the ability to respond in real time and reduces communication to a retrospective explanation rather than a proactive source of guidance.

From the utility perspective, transactional engagement also restricts the ability to influence customer behavior in meaningful ways. Without visibility into how everyday decisions affect energy usage, consumption feels abstract and disconnected. Even when information is accurate, it often fails to drive action because it arrives too late to matter. When communication channels are used primarily for record keeping, customers gain little sense of empowerment or support, which can discourage participation in programs aimed at improving efficiency or managing demand.

To redefine this relationship, utilities must communicate at moments when guidance can influence outcomes rather than explain results after the fact. For example, utilities can notify customers when EV charging coincides with peak pricing periods, prompting them to delay charging to avoid higher costs. Insights delivered at the point of decision—rather than at the end of a billing cycle—are far more likely to change behavior and create shared value.

Why personalization now defines customer experience

As energy costs rise, expectations for proactive and personalized communication rise alongside them. According to **J.D. Power**, average residential utility costs have increased more than 30% since 2020, intensifying customer sensitivity to both usage and pricing. Customers increasingly expect communication that is relevant to their specific situation and delivered when it is most useful, not generic alerts that offer little actionable guidance.

Alerts that lack specificity or recommendations that fail to reflect actual behavior are easily ignored, undermining the effectiveness of programs designed to encourage new habits. In contrast, personalized communication creates immediate and tangible value. Utilities can alert customers when heating or cooling usage exceeds seasonal norms or recommend optimal times to run energy-intensive appliances based on time-of-use rates. When guidance aligns directly with individual usage patterns, it is easier to understand and act on and more likely to shape outcomes.

Over time, these tailored interactions strengthen engagement and reinforce the utility's role as a trusted source of insight rather than a transactional service provider. Personalization shifts communication from a passive, retrospective function to a mechanism for influencing real-time decisions.

Data as the foundation for advisory engagement

Delivering personalized guidance at scale requires access to granular, high-quality data. Utilities are collecting unprecedented volumes of information, but the value of that data depends on how effectively it is transformed into action. As utilities shift toward advisory engagement models, data becomes a critical enabler of affordability, customer empowerment and more informed decision-making across the system.

According to the **U.S. Energy Information Administration**, U.S. electricity prices have risen more than 8% year over year. Combined with broader economic pressure, this trend has increased demand for clearer cost visibility and control. Customers want insight that helps them avoid unexpected bill spikes and understand how individual decisions influence expenses before costs are incurred. To support this level of guidance, utilities must ground recommendations in an accurate understanding of actual usage patterns rather than assumptions tied to static billing cycles or generalized customer profiles.

Behavior-based segmentation allows utilities to intervene at the right time before inefficiencies escalate or costs increase. Timely insight shifts the conversation from reaction to prevention, supporting both customer outcomes and operational efficiency while reinforcing trust in the guidance being provided. Rather than treating engagement as a batch process tied to monthly statements, utilities can begin delivering situational insight aligned with real-world behavior.

Beyond improving individual interactions, data-driven engagement also helps utilities understand how customers respond to guidance over time. By observing patterns, such as whether customers consistently adjust usage after receiving recommendations, utilities can evaluate which messages are effective and refine future communication strategies. This feedback loop transforms engagement from a one-way broadcast into an adaptive system that becomes increasingly precise. Importantly, this capability also helps utilities avoid over-communicating. Without insight into what resonates, organizations risk overwhelming customers with alerts that feel repetitive or irrelevant. Data allows utilities to prioritize quality over quantity, delivering fewer messages with a clearer purpose and higher value. When communication is precise and situational, customers are more likely to trust the guidance and act on it.

As utilities face increasing pressure to balance affordability, reliability and customer satisfaction, this approach becomes essential. Engagement grounded in data not only supports better decision-making for customers, but also provides utilities with measurable indicators of program effectiveness, participation and long-term impact—a sure way to strengthen the business case for continued investment in intelligence-driven engagement.

Unlocking real-time insight with grid edge intelligence

Turning data into real-time guidance requires analyzing information closer to where it's generated. Grid edge intelligence (GEI) enables utilities to collect, process and analyze energy data at the edge of the grid through distributed intelligence embedded in meters, sensors and other devices. Instead of sending all information back to centralized systems for delayed analysis, GEI allows insights to be generated where energy is consumed.

This approach significantly reduces latency and enables faster pattern recognition, enabling more responsive customer engagement while improving operational awareness. Utilities can identify local consumption trends, detect anomalies and assess how customer behavior affects grid performance in near real time. These capabilities strengthen coordination between customer communication and system management, aligning engagement strategies with operational realities.

GEI also creates a more efficient pathway for managing data volumes. By processing information locally and transmitting only relevant insights, utilities can improve system performance while ensuring communications remain targeted and meaningful rather than overwhelming.

Artificial intelligence as an enabler of proactive engagement

As utilities invest in GEI, artificial intelligence (AI) becomes essential for unlocking its full value. According to **Deloitte**, nearly 40% of utility control rooms are expected to use AI by 2027, reflecting a growing shift toward predictive, data-driven operations. Machine learning helps identify patterns that traditional analysis may miss, detect anomalies and anticipate emerging issues across complex systems.

From a customer engagement perspective, AI enhances the ability to deliver forward-looking guidance. By analyzing historical usage alongside external factors such as weather or regional demand conditions, utilities can anticipate consumption trends and deliver recommendations before issues arise. Customers receive actionable insights that help them prepare for upcoming conditions, rather than respond after the fact.

Operationally, AI enables continuous improvement. Systems learn from customer responses, refining recommendations over time and increasing accuracy as behavior evolves. When combined with live data from the grid edge, this creates a dynamic feedback loop that strengthens both engagement and system performance.

Building trust through transparency and relevance

Effective engagement cannot rely on data alone—it must be grounded in trust and transparency. Customers want to understand how their data is used and why specific recommendations are delivered. Clear context builds confidence and reduces concern. For example, an energy usage alert that explains it is based on consumption between specific hours during the past billing period provides clarity and reinforces relevance.

Utilities must also balance personalization with privacy. Organizations must be careful to respect boundaries and ensure that when they provide valuable, personalized insights, they also protect sensitive personal information. Consistency across communications further strengthens trust. Each interaction should reinforce the value of the relationship by delivering accurate, relevant insight aligned with customer needs. Once established, trust becomes a powerful driver of participation in programs that support efficiency, affordability and demand management.

Operational impact of customer-centric engagement

A customer-centric engagement model reshapes utility operations as much as it improves experience. Proactive communication reduces avoidable customer service inquiries, allowing support teams to focus on complex issues rather than preventable concerns. At the same time, analytics-driven insight enables utilities to anticipate demand patterns and allocate resources more effectively, reducing strain on infrastructure and improving reliability.

Engaged customers also contribute to greater system predictability. When behavior aligns more closely with operational needs, utilities gain greater flexibility in managing loads across varying conditions. These improvements create a reinforcing cycle in which better insight leads to better engagement, stronger relationships and improved outcomes across the system.

Delaying this transformation can compound challenges. As expectations evolve, utilities that rely on outdated engagement models risk declining satisfaction, heightened regulatory scrutiny and reduced effectiveness of initiatives that depend on active customer participation.

Creating a scalable model that redefines the future of utilities

To support long-term transformation, utilities must invest in infrastructure that enables real time data processing and scalable engagement. Advanced metering systems combined with GEI, provide the foundation, while distributed intelligence platforms enable faster analysis and response. Together, these technologies support repeatable, data driven engagement models.

Implementation requires cross-functional collaboration. Customer experience teams, operations groups and data specialists must work together to align strategy and execution. Early use cases that deliver measurable results help build internal momentum and confidence, ensuring insights translate into effective communication rather than remaining theoretical capabilities.

As these capabilities mature, utilities must rethink their role within the customer relationship. Engagement becomes a strategic function, not a downstream activity. By positioning themselves as advisors, utilities create collaborative relationships that encourage participation and support demand flexibility, efficiency and affordability goals.

A new era for utility engagement

Customers are moving beyond purely transactional service models and increasingly expect communication that is timely, relevant and actionable. Meeting these expectations requires utilities to treat engagement as a strategic capability rooted in data and informed by insight that customers can trust.

When grid-edge intelligence and artificial intelligence work together, utilities gain the ability to deliver individualized guidance at scale while improving operational awareness. Those that embrace this shift can strengthen customer relationships, enhance grid reliability and take on a more active role in managing the evolving energy ecosystem.

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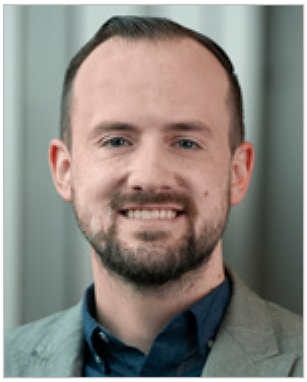
WHEN DATA CENTERS SHAPE THE GRID

HOW AI-DRIVEN DEMAND IS RESHAPING TRANSMISSION, DISTRIBUTION AND MEDIUM VOLTAGE ARCHITECTURES

KYLE STROMBERG



The global power sector is entering a period of sustained change. According to the Electricity 2025 report from the International Energy Agency (IEA), electricity consumption is expected to grow steadily through 2027, driven by electrification across transportation, buildings and industry.

Within that broader shift, data centers stand out. Research from Goldman Sachs suggests that global data center power consumption could increase by roughly 50% by 2027 and as much as 175% by the end of the decade. Much of that growth is tied to artificial intelligence (AI), which is rapidly changing both the scale and the profile of data center loads.

What matters here is not just the magnitude of demand, but how it behaves. Data centers are no longer just large electricity consumers. In many cases, they are beginning to influence how power systems are planned, operated and even designed.

A different kind of load

The U.S. grid has always had to deal with growth. What's different now is the type of load being added. AI-driven data centers combine several characteristics that rarely appeared together in traditional industrial loads:

- Very high-power density (GPU-intensive racks now draw 50-100 kW or more – several times the historical norm of 10-20 kW)
- Continuous, 24/7 operation
- Tight tolerances for power quality
- The ability to scale quickly

That combination changes the planning equation. In regions with heavy data center development, utilities are seeing energy use rise faster – and in more concentrated ways – than in the past.

Instead of broad, gradual load growth, demand is showing up in clusters. Transmission systems and emerging on-site generation must deliver large amounts of power into specific areas, while local distribution networks are expected to support sustained, high-capacity loads with little margin for disruption.

This is forcing a shift in how infrastructure is planned. Forecasting is more uncertain. Timelines are tighter. And in many cases, the traditional sequence of plan-permit-build is struggling to keep up.

AI: More than just demand

AI is often described as an energy-intensive technology, and that's true as far as it goes. Training large models requires substantial computer resources, often running continuously across thousands of processors. At scale, even inference workloads that handle everyday queries add up quickly.

But this view only captures part of the picture. AI is also becoming a tool for managing the systems it puts pressure on. Inside data centers, it's already being used to optimize workload placement, improve cooling performance and identify equipment issues before they lead to failures.

At the grid level, similar approaches are being explored for power consumption forecasting and system balancing, especially as more variable renewable generation comes online. So, while AI is clearly contributing to load growth, it is also helping operators make better use of the infrastructure they already have.

Both dynamics are happening simultaneously.

Transmission and distribution under pressure

The effects of data center growth show up differently across the grid. On the transmission side, the challenge is scale. Moving large blocks of power over long distances takes time to plan and even longer to build. Permitting, siting and cost all play a role, and lead times can stretch into years.

On the distribution side, the timeline is shorter and often more urgent. Substations, feeders and transformers in high-growth areas can approach capacity limits quickly – sometimes faster than expected.

Several issues are becoming more common:

- Localized congestion in data center hubs
- Increased sensitivity to power quality issues
- The need for faster infrastructure upgrades

One key challenge is that these pressures are not evenly distributed. They tend to be highly localized and they don't always align with long-term planning assumptions. That makes coordination between utilities, developers and regulators more important – and more complex.

Data center capacity and utilization trends

These shifts are already influencing how equipment is specified, deployed and maintained across both utility and data center environments.

Another dimension of AI-driven load growth is how quickly data center capacity is being absorbed. Industry insights, including analysis from Goldman Sachs Research and similar firms across the sector, show that AI workloads are taking up a growing share of total capacity.

The share of total capacity is projected to grow from roughly 14% to more than a quarter of total data center power demand by 2027. Meanwhile, overall data center power consumption could rise by roughly 175% by 2030 compared with 2023 levels.

Utilization levels provide additional context. Occupancy has already pushed into the mid-90% range in key markets, leaving virtually no headroom for new high-density workloads. Under these conditions, even incremental increases in demand can quickly translate into added strain on power delivery and cooling systems.

For grid operators, this creates both urgency and uncertainty. High utilization requires new supply to sustain growth. At the same time, variability in AI adoption complicates planning timelines. In regions with concentrated data center development, small forecasting gaps can have outsized impacts on infrastructure readiness, reliability and cost.

These dynamics reinforce a central point: as utilization rises, operational intensity becomes a key factor in how the grid is planned and managed. Aligning capacity expansion with evolving demand will be critical to maintaining system stability and supporting continued growth in AI-driven workloads.

From load centers to energy nodes

At the same time, data centers themselves are changing. Many large facilities are no longer designed as purely passive loads. Instead, they are incorporating additional energy capabilities that allow them to interact with the grid in more flexible ways:

- On-site generation resources
- Long-term renewable energy agreements
- Battery storage systems
- Participation in demand response programs

In practice, this means data centers can adjust how and when they draw power. In some cases, they can reduce peak demand or shift load in response to grid conditions.

This does not eliminate the need for new infrastructure. But it does introduce a more dynamic relationship between large energy users and the grid – one that wasn't common even a decade ago.

Rethinking power distribution inside the data center

Changes aren't limited to how data centers interact with the grid. They are also happening inside the facility. As power densities increase, traditional low-voltage distribution approaches become harder to scale efficiently. This has led to a growing interest in medium-voltage (MV) architectures.

By distributing power at higher voltages deeper into the facility, operators can reduce losses, simplify cabling and better support high-capacity deployments. What used to be a secondary design decision is now central to how large data centers are built.

There is also increasing attention on converting more of the supply to load power architecture, using more DC vs. traditional AC systems. While still early, enabling technologies are being explored in both research and pilot environments, particularly to reduce conversion steps and align more directly with DC-based computing loads.

There are still open questions – particularly around protection coordination, standards harmonization and interoperability across equipment from different manufacturers. In North America, for example, data center MV systems are typically specified under IEEE standards (notably C37.74 for padmount switchgear). But the rapid growth of the market has attracted IEC-tested equipment that is evaluated under different testing standards.

As both standards frameworks coexist on the same sites, questions of compatibility, certification and long-term maintainability are becoming more pressing. For emerging system architectures that rely on DC, the challenges are even more fundamental: protection schemes, fault interruption methods and safety standards are still maturing.

Even so, the direction of travel is becoming clearer. As computing loads evolve, so do the expectations placed on electrical architecture – and so does the urgency of resolving these technical foundations.

The growing importance of system visibility

As both grid conditions and data center operations become more complex, visibility into electrical systems is becoming more important. Operators require more detailed, real-time insight into system performance – how power is flowing, where constraints are emerging, how equipment is operating under load and where risks may be developing. This has led to broader adoption of monitoring, sensing and analytics capabilities across electrical infrastructures.

These tools support:

- Earlier identification of potential issues
- More informed operational and maintenance decisions
- Improved alignment between facility demands and grid conditions

In practice, the demand for visibility is outpacing what many installed systems were designed to provide. Data center operators increasingly expect remote monitoring to be a standard capability, not a premium add-on. Fault detection, automated diagnostics and integration with facility-wide energy and power management systems (EPMS) are also becoming baseline requirements.

At the same time, the commissioning process itself is under pressure. The expectation for rigorous factory and site acceptance testing has intensified, even as project timelines compress. The gap between what operators need in system visibility and what the supply chain currently delivers at scale remains one of the less discussed but more consequential constraints in the market.

Taken together, these developments point toward a more integrated model in which electrical systems are expected to respond with the same level of flexibility as the digital workloads they support.

Looking ahead

Demand for data center capacity is expected to remain strong through the end of the decade. Even as new facilities are built and efficiency improves, the overall trajectory points upward.

Meeting this level of consumption will require coordinated efforts across several areas:

- Expanding and modernizing grid infrastructure
- Integrating additional low-carbon generation
- Deploying energy storage and flexible resources
- Continuing to improve efficiency at the facility level
- Addressing equipment lead times and supply chain bottlenecks that constrain the pace of deployment

AI will play a role here as well, not just in driving demand, but in helping manage it.

An evolving grid

The relationship between data centers and the power grid is changing. What was once a relatively straightforward model – centralized generation supplying large but predictable loads – is becoming more dynamic. Data centers are growing in scale, but they are also becoming more flexible, more integrated and in some cases, more active in how they interact with the grid.

The shift has implications beyond any single technology. It affects how infrastructure is planned, how power is distributed and how resilience is built into the system.

In that sense, the rise of data centers is not just a demand story. They are part of a broader transition toward a grid that is more adaptive, more interconnected and increasingly shaped by the digital systems it supports.

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GUEST EDITORIAL

THE SMART METER PARADOX:
SCALING SIMPLE TECHNOLOGY WHILE MASTERING COMPLEXITY

JESSICA LYMAN

Utilities have spent more than a decade deploying smart meters across their service territories. In many regions, those rollouts are now largely complete.

Once deployments settle into a steady cadence, the work becomes familiar. Crews are scheduled, routes are optimized and productivity is tracked. Utilities know how to execute field operations — this is work the industry has done successfully done for generations.

The harder challenge begins after the meters are installed.

A utility that once received a single meter read per customer each month is suddenly managing 96 readings per day, along with alarms and event notifications generated by the device itself. At that point, the problem is no longer installation. It is deciding what to do with the flood of information now arriving from the grid — and how to turn that data into measurable operational and customer value.

Metering itself is not new. Utilities have always needed to measure electricity consumption to bill customers. Advanced metering infrastructure (AMI) did not change that fundamental requirement. What changed was the scale and granularity of the available data, opening the door to new use cases that extend far beyond billing. Unlocking that value, however, requires a deliberate approach — one that aligns data capabilities to a utility's specific operational priorities rather than treating AMI data as an abstract analytics problem.

A data revolution

Monthly meter reads offered only a narrow snapshot of customer energy use. With smart meters in place, utilities can now see how electricity consumption changes throughout the day. Customers gain insight into when their usage rises and falls, while utilities begin to observe patterns across neighborhoods, feeders and circuits that were previously invisible.

The scale of this data grows quickly.

In a system with two million meters, hundreds of millions of readings may be generated each day. On most days, roughly 99% of those devices are operating normally. The challenge is identifying the small fraction that are not, and doing so quickly enough to act.

Within that stream of data may be early signs of a voltage problem, degrading equipment or the conditions that precede an outage. The utilities that succeed are often those that take a use-case-driven approach to AMI data — starting with the operational questions they want to answer, then configuring systems and analytics to surface the signals that matter most. This approach helps organizations move from data accumulation to actionable insight, rather than being overwhelmed by volume.

This shift also changes how utilities organize work internally. Historically, responsibilities were clearly divided. Field crews managed poles, wires and meters, while customer service and IT teams ran billing systems and customer databases. Smart meters blurred that boundary. Devices in the field now produce continuous operational data that ultimately informs grid operations.

Utilities with experience supporting large-scale AMI deployments have learned that technology transitions are rarely isolated events. Meters, head-end systems, MDMS platforms, analytics tools and operational systems must evolve together. Organizations that plan for this transition — leveraging lessons learned across multiple deployments — tend to experience smoother integration across platforms and fewer disruptions in day-to-day operations.

Customers felt the change as well. The monthly bill was no longer the only window into energy use. Many utilities introduced tools that allow customers to track consumption throughout the day, compare usage with similar households or understand when demand peaks. These early customer-facing use cases often serve as an entry point, demonstrating value quickly while laying the groundwork for more advanced applications.

The data also began revealing conditions on the grid itself. In one instance, meter data signaled abnormal activity associated with a transformer. When crews inspected the site, they found visible arcing and char marks on the transformer terminals. The equipment was still operating, but failure was inevitable.

Because the issue first surfaced in the meter data, the utility was able to repair the equipment before it failed and caused an outage. Examples like this highlight how AMI data, when tied to clearly defined operational use cases, can support proactive maintenance and improved reliability.

From collection to insight

The systems surrounding smart meters are evolving as well.

Early AMI deployments followed a centralized model: meters transmitted data back to the utility, where systems and analysts sorted through it. Newer architectures allow some evaluation to occur closer to the source, with devices monitoring specific conditions and generating alerts when thresholds are crossed.

This shift reduces the volume of data operators must sift through and accelerates response times. More importantly, it allows utilities to prioritize and release AMI use cases incrementally, enabling value to be realized sooner rather than waiting for a fully mature analytics ecosystem.

Utilities that leverage a structured catalog of AMI use cases and deploy them through phased release cycles are often able to move into optimization sooner. Early releases may focus on outage detection, voltage monitoring or customer engagement, while later phases expand into asset health, DER integration and advanced grid analytics. This staged approach supports continuous improvement while maintaining organizational momentum.

Meters are also increasingly integrated with other grid systems. Utilities combine AMI data with information from distribution management systems, distributed energy resource platforms and additional sensors across the network. Together, these systems provide a more complete and dynamic view of the distribution grid.

Where specific functions reside varies by utility. Some capabilities are housed within the AMI platform, while others sit in distribution management systems or related operational software. Utilities with experience navigating multiple AMI and grid technology transitions often focus less on where a function "should" live and more on how data flows across platforms to support timely decision-making.

No longer just a cash register

The industry has already demonstrated that it can deploy smart meters at scale. What takes longer is determining how the surrounding systems — and the organizations that operate them — should work together once the devices are in the field.

Utilities that adopt a value-focused, use-case-driven approach — supported by experienced AMI deployment partners — are better positioned to move from installation to optimization. They can detect equipment issues earlier, address them before they escalate into outages and maintain power quality as the grid incorporates renewable generation, distributed energy resources and electric vehicles.

In that environment, the meter is no longer just a cash register. It is a foundational operational device — one that, when paired with the right use cases and delivery strategy, helps utilities manage a more complex grid while realizing value from AMI data sooner and more sustainably.

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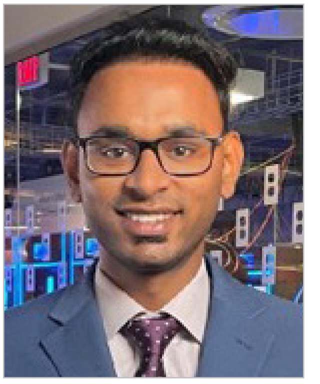
GUEST EDITORIAL

VIRTUAL POWER PLANTS:
KEY TOOLS TO ACHIEVING A MORE RELIABLE AND SECURE ENERGY FUTURE



SHIKHAR PANDEY

With energy demand increasing, traditional fossil fuel assets phasing out and security risks growing, Virtual Power Plants (VPPs) are becoming an increasingly important tool to facilitate the global energy transition.

VPPs are connected systems of distributed energy resources – like solar, batteries and generators – capable of supplying power to the grid. They can play a critical role in supporting future energy growth and infrastructure security by providing gigawatts of clean energy capacity during emergencies and periods of high demand.

As outlined in a new report from IEEE Power & Energy Society (PES), **Virtual Power Plants: A Critical Assessment of Their Role in Energy Security**, VPPs are an invaluable tool that grid operators and regulators should deploy at scale over the next decade. It's not a one-size-fits-all solution, but it will make significant progress in increasing all energy capacity and mitigating grid security challenges.

VPPs also help improve grid reliability by reducing the need for traditional power-generating infrastructure, which can take years and require a significant investment to deploy. In fact, pilot programs in the U.S., Australia and New Zealand have shown that VPPs can be reliably dispatched to support the grid during periods of highest risk.

For example, Pacific Gas & Electric (PG&E) and Sunrun launched a first-of-its-kind residential battery VPP pilot in Northern California in response to California's record heat waves earlier this decade. By the summer of 2023, the VPP provided an average of 27 MW of dispatchable capacity during peak hours for over 90 consecutive days, offering a dependable daily resource to the grid that became operational only six months after the contract was signed.

The case for VPPs

VPPs are an optimal solution in times of crisis and high demand. Whereas traditional power-generating assets are cumbersome to build, costly to operationalize and can take years to be energized, VPPs can be stood up in far less time and are highly responsive to grid emergencies, as PG&E and Sunrun have shown so far in their pilot program.

VPPs should not be deployed as all-purpose grid resources, but as high-value, fast-response capacity for peak and emergency conditions.

What's more, VPPs can also provide energy to targeted geographic areas, enabling them to address demand where needs and volatility are highest. It is also worth noting that VPPs mitigate growing security concerns because they leverage reliable, controllable assets behind the meter. It's clear that the growth of VPPs can help provide resiliency and security to the electric grid. However, to better enable VPPs as an option during emergencies and moments of high risk, grid operators and regulators must focus on a series of goals to improve connections and reform market incentives to increase overall VPP adoption.

Goal #1: Meet short-term grid security & capacity needs

Grid operators and regulators must ensure VPPs can be utilized at scale during emergencies or when demand surpasses supply. To better prepare for these security and capacity needs, it's critical that grid operators and regulators create incentive programs that are best suited for the functions of VPPs. Doing this will encourage more utility operators and consumers to participate, as was evident in the Southern California Edison VPP pilot with Tesla.

The program began with volunteer Tesla Powerwall owners in 2021, but it saw substantial growth in participation when it began offering $2 per kWh payments for energy fed into the grid during emergencies. By 2023, the VPP exceeded 100 MW of aggregate capable capacity, a milestone that shows just how quickly these programs can scale when incentives are aligned.

In the immediate term, decision-makers should also lower the barriers to adoption in ancillary service markets, making participation more accessible. And finally, they should require utilities to run transparent procurement processes with full consideration for how VPPs can replace infrastructure upgrades and save ratepayers money.

Goal #2: Provide long-term security & meet capacity strains more reliably

To ensure VPPs can meet non-negotiable reliability and security needs, operators and regulators will need to take even bolder actions. For one, they should reserve capacity for critical grid needs by locking in "must-run" support via long-term contracts. It's also critical that the energy generated by VPPs is sold to other providers only when it's not already committed to improving reliability service.

Lastly, basing payments on the amount of energy flowing in and out will provide a clear view of the value each VPP contributes to the grid. SolarZero's VPP pilot in New Zealand, detailed in the **IEEE PES Technical Report**, demonstrated that VPPs can deliver measurable value, but capturing that value at scale requires systemic changes beyond individual pilots.

Goal #3: Build more VPP-connected grids

To allow for VPPs to expand systemwide and meet current and future energy needs, regulators should take three additional actions.

- First, they should mandate foundational infrastructure upgrades that encourage advancement by setting clear, enforceable deadlines to install smart technology and build new processes.
- Second, to further integrate VPPs into grid operations, regulators should incentivize innovation to motivate utilities to embrace and deploy the technology.
- Finally, regulations should be set that drive interoperability by referencing open standards and making compliance a condition for utility cost recovery or program funding.

What's next?

Adopting VPPs is a critical piece of the global energy transition. Deploying the technology at scale will help address growing demand and strengthen energy security, but this will only happen with collaborative action among grid operators, regulators and utilities.

Taking concrete steps together to support VPP growth will help bridge the demand gap and chart a clear path forward as we navigate the next decade of energy and beyond.

With more than a decade of experience in power systems and smart grid innovation, Dr. Shikhar Pandey is principal at Grid CoGroup and has held senior leadership roles at Commonwealth Edison, where he led distributed energy resource planning, storm performance analytics and regulatory strategy. He holds a Ph.D. in power systems and an MBA from the University of Chicago Booth School of Business. He currently serves as chair of the IEEE Task Forces on Distribution Resiliency and Grid Flexibility and as the secretary of the IEEE Industrial Technical Support Leadership Committee (ITSLC).

About IEEE Power & Energy Society (PES)

The IEEE Power & Energy Society (PES) is the leading provider of scientific and engineering information on electric power & energy for the betterment of society and a trusted resource dedicated to the technical, informational, networking and professional development needs of its members. With nearly 40,000 members around the globe representing every facet of the electric power and energy industry, PES is at the forefront of the rapidly changing technological advancements that impact everyone's future. Additional information on IEEE PES can be found at **ieee-pes.org**.

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DEBUNKING COMMON UTILITY CYBERSECURITY MYTHS

WHY UNDERSTANDING POPULAR MISCONCEPTIONS CAN HELP PROVIDERS PROTECT CRITICAL INFRASTRUCTURE IN 2026 AND BEYOND

VICTOR ATKINS AND ADAM SPRATT

In 2026, few operational priorities are more critical than cybersecurity, as a cyberattack can have devastating impacts with consequences for both a utility's infrastructure and its customers. So why do so many cybersecurity myths persist in the industry?

Utility leaders in 2026 should approach cybersecurity with eyes wide open. That means setting the record straight on both the actors who seek to attack critical infrastructure, as well as the practices and principles that will be most effective in stopping them.

Myth: Cyberattackers are mostly private entities acting for profit

For years, the common view of cyberattackers, shaped primarily by Hollywood, has been of lone-wolf actors or faceless entities seeking to cause chaos and steal data for profit, revenge or no reason at all. This view, while not always inaccurate, is simply incomplete when examining the threat landscape in 2026.

The current geopolitical environment paints a much more complicated picture. Cyberattacks can come from a multitude of actors motivated by different aims, but among the greatest emerging threats are nation-states. Modern warfare, as illustrated by the war in Ukraine, has moved the fight beyond the battlefield. In 2022, Russia carried out cyberattacks aimed at sabotaging Ukraine's satellite communications before it moved in with its physical invasion. The impact of these attacks was widespread, disrupting services across the EU and affecting nearly 6,000 wind turbines in Germany.

More recently, in December of 2025, Russia-linked groups associated with the GRU **attempted to disrupt power delivery in Poland** by targeting communication links between renewable generation sites and the operators who manage them during peak winter stress. Instead of using tailored malware against a transmission substation or control center, the attackers targeted the communication layers carrying the telemetry data that operators rely upon for visibility and control. By cutting off that information across many small DER sites at once, the attackers increased the risk of frequency disturbances and potential load shedding during peak cold weather demand. Had the attack succeeded, nearly 500,000 people could have lost power and heat in extreme cold.

These attacks have significant short- and long-term implications for North American operators. The indication from high-ranking officials is that China intends to **take Taiwan by 2027**, and intelligence agencies have confirmed that Chinese state-sponsored actors are positioned to launch cyberattacks in the event of a conflict that involves the United States. For this reason, civilian infrastructure (including public utilities) and military networks could be attractive targets in such a scenario.

Domestic threats persist and complement these geopolitical concerns, as threat actors target both public and private organizations, including utilities. Vendors with hidden or masked foreign ownership are becoming more involved in local contracts, multiplying supply chain risks. And insider threats are ever-present as bad actors recruit and bribe employees via shady online forums to sell network access.

The ramifications of an attack on utilities are potentially devastating for both the organization and its customers. Recent natural disasters, such as Hurricane Helene, have shown the lasting damage a wide-scale outage can have on utility customers. Hospitals can lose power and water treatment plants can shut down for months, risking the health and safety of thousands. Even banks and grocery stores can be severely disrupted, leaving many without access to essential resources. These are just a few of the possible impacts of a cyberattack on utility infrastructure, and the likelihood of these attacks due to the rising number of global threats has become a matter of not "if," but "when."

Myth: Threat actors only target IT systems

Many utilities assume that cyber threats target only IT resources. However, cyberattacks can target any number of entry points in a utility across an ecosystem of wireless, microwave, satellite and cloud-based connections, any one of which can be vulnerable to attack if not sufficiently protected. Organizations that limit responsibility for cybersecurity only to IT can overlook these assets and put critical systems at risk.

A good example is the coordination of distributed energy resources (DERs). Utilities are integrating more renewable energy, battery energy storage and other resources across the grid and managing them via a communication network. This can create potential vulnerability points with each new resource added, and both the network as well as the DERs themselves require protection from threats.

One important consideration in securing connected network assets is to leverage private broadband communication, which has become a critical component of grid modernization for many utilities. Private LTE (PLTE) networks can enable high-speed coordination of DERS and other resources and enhance overall resiliency. More importantly, however, PLTE networks offer significant security benefits over public or "mesh" networks, making them an essential tool in utilities' cybersecurity strategies.

A PLTE network comes with inherent cybersecurity features and gives utilities full ownership and control of the network. Utilities can embed utility-grade reliability and advanced security controls into the overall network design, while being better positioned to respond quickly to potential threats by owning and designing the network. And because the networks operate at high speeds, operators can quickly detect anomalies, close traffic "black holes" and enforce policies around segmentation, roaming and third-party access to help protect critical infrastructure from being compromised.

It's clear that while IT assets can certainly be a target for malicious actors, IT is only one piece of the cybersecurity puzzle for utilities.

Myth: Cybersecurity is only IT's concern

Because business leaders tend to view cybersecurity as an IT problem, many miss the risks it poses to the bottom line and consider it the IT department's responsibility. But cybersecurity is first and foremost a business risk, and as such requires an organization-wide approach. For critical infrastructure owners and operators, that risk extends beyond financial and operational impacts to include the safety of employees in the field and the general public, who depend on reliable services.

The most effective cybersecurity strategies are woven into the organization's DNA from the top down. Accountability must extend to the board level, and the C-suite should make security a priority by defining roles clearly across all business units. The **costs of failure** for utilities are simply too great to ignore.

This can be easier said than done when it comes to financing cybersecurity efforts. Budgets for defense are frequently considered operating expenses and are therefore constantly under scrutiny. Effective cybersecurity can be difficult to quantify as it is not a revenue-generating activity for the business and, in the best-case scenario, nothing happens, and the ability to generate revenue from other parts of the business is maintained. While this looks good for an IT administrator, it can make the business case for further investment difficult to demonstrate.

Utilities need to reframe cybersecurity as a business necessity, one that is essential to ensuring continuity, mitigating risk and protecting brand reputation. This can help change the perception of security from a mere cost center to a strategic imperative for the business.

In addition to upgrading to a private network, utilities can implement several tactics to strengthen cybersecurity and improve network visibility. They should:

- **Strengthen hygiene:** Patch systems, block common threats and monitor well-known vulnerabilities.
- **Establish baselines:** Ensure adequate detection and train staff to respond to anomalies such as "living off the land" attacks using legitimate tools like PowerShell.
- **Test resilience:** Conduct regular exercises for business continuity and disaster recovery, simulating the loss of both IT and OT systems.
- **Invest in people:** Avoid skill stagnation with ongoing training, conferences and cross-functional exercises.
- **Scrutinize vendors:** Contracts don't reduce operational risks, and they don't transfer accountability. Require vendors that can access your systems to show clear, transparent evidence that their own security program is robust and meets industry standards, because the responsibility for an attack ultimately falls on the utility.

Utilities can also build security strategies and evaluate programs using the National Institute of Standards and Technology's **cybersecurity framework**. Many are adopting zero-trust and micro segmentation architectures, stress-testing continuity plans and treating vendor risk as a shared responsibility.

Finally, utilities should bake cyber resilience into their organizational culture. This means investing in training and professional development opportunities to keep staff agile, while incorporating cross-functional exercises to help prepare teams for a crisis. Rather than instill fear, good training helps create a healthy respect for cybersecurity as a foundational element of resilience.

A changing environment

The cyber threat landscape is shifting. Regardless of where attacks are coming from, threat actors are relentlessly seeking out vulnerabilities in utility infrastructure and systems, and the impacts of an attack can be devastating for any utility. By focusing on organizational awareness and vigilance and understanding the full scope of the cybersecurity paradigm in 2026, utilities can give both leaders and their workers the ability to protect both the organization's bottom line and the well-being of the communities they serve.

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POWHERFUL FORCES

BRIDGING STRATEGY AND THE GRID: A PROFILE OF ANN MOORE

ELISABETH MONAGHAN

Ann Moore has spent her career standing at the intersection of strategy and execution. As industry principal for Power & Utilities at AVEVA, she draws upon both perspectives every day.

"In my role at AVEVA as Industry Principal-Power & Utilities, I focus on working closely with utilities, regulators and industry partners to help translate strategic priorities such as grid modernization, resilience and reliability into practical, scalable execution," she explains. "A big part of what I do is to address the gap between technology and real-world operations, ensuring that solutions align with the complexities utilities are facing on the ground."

Much of that work takes place during conversations. Moore spends significant time facilitating dialogue across the energy ecosystem, connecting peers, surfacing shared challenges and turning collective insight into action. It's a role she finds energizing.

"The most interesting part of my job is the opportunity to engage with utilities globally across the energy ecosystem, all of which are tackling similar challenges in very different ways," she says. "No two utilities are the same and seeing how each organization approaches transformation, whether in digitalization, resilience, or workforce evolution, is incredibly insightful."

That enthusiasm for the practical side of transformation is rooted in experience. Before joining OSIsoft — now part of AVEVA — Moore spent years working in grid operations at San Diego Gas & Electric. It's a background that gave her keen insight into what modernization actually requires.

"Grid modernization is not just a technology challenge; it's also operational, organizational and cultural," Moore says. "I've learned that success depends on how well new capabilities integrate with existing processes, systems and workforce realities." Her approach, she says, is to focus "less on 'big ideas' in isolation and more on how those ideas can be implemented incrementally, with clear value at each step."

At AVEVA, that philosophy has translated into tangible accomplishments. Moore counts among her proudest achievements the creation of the Utility Executive Summit, a forum for senior industry leaders to share candid lessons and forge working relationships.

"These conversations often lead to tangible actions and collaborations that extend well beyond the event itself," she notes.

When asked what technology companies most often get wrong in the grid modernization space, Moore points to a persistent gap between technology capabilities and utility realities. "Utilities operate in highly complex, regulated environments with legacy infrastructure, and introducing new technologies requires careful integration rather than disruption," Moore says.

Beyond that, she argues, providers must make the value case clearly and concretely: "Utilities are under increasing pressure to justify investments, so technology providers must go beyond innovation and show how solutions improve reliability, resilience and cost-effectiveness in tangible ways."

According to Moore, AVEVA excels in its long-term, agnostic, platform-based and partnership-oriented approach. Instead of focusing solely on individual and siloed solutions, there is a strong emphasis on understanding the broader operational context and working alongside customers over time.

Equally important, she adds, is AVEVA's focus on enabling integration and interoperability: "In a space as complex as energy, no single solution operates in isolation, and supporting an open, connected ecosystem is critical to long-term success."

Looking ahead, Moore believes that the industry's most impactful developments will be in advanced analytics.

"As the grid becomes more distributed, complex and dynamic, having real-time insights and predictive capabilities will be essential for maintaining stability." At the same time, Moore says that technology alone won't be enough. "Market and regulatory evolution, particularly around distributed energy resources and load growth, will play a significant role. Technology alone isn't enough; it must be supported by frameworks that enable flexibility and coordination."

Considering the broader question of reaching 100% renewables by 2050, Moore takes a multi-dimensional view. "Achieving 100% renewable energy will require alignment across multiple dimensions," she says. "Technically, we need more advanced grid management capabilities to handle variability and complexity. Economically, there must be continued investment in infrastructure and incentives that support long-term resilience and flexibility."

Looking at the role of politics and regulations, Moore emphasizes balance: "Policies that encourage public-private partnerships, streamline approvals and support modernization efforts will be key to accelerating progress."

Moore doesn't hesitate to point out which industry challenges she believes deserve more attention. Workforce transformation, she says, is one challenge to consider: "As the grid evolves, so do the skills required to operate and maintain it."

Another notable challenge is supply chain resilience. "Utilities are facing longer lead times, equipment shortages and increased dependency on global suppliers, all of which can delay critical infrastructure projects and modernization efforts," Moore observes. "Building more resilient, transparent and flexible supply chains, beyond simply extending the asset lifespans, is becoming just as critical as deploying new technologies."

Finally, the challenges associated with organizational change management remain a key factor. Industry experts often talk about technology adoption, but the internal processes and cultural shifts required to support that adoption are equally important and often more difficult to implement successfully.

What keeps Moore motivated through it all is the opportunity to contribute something that has both immediate and long-term impact. "The work we do today will shape the resilience, sustainability and reliability of energy systems for decades to come, and that's a responsibility I take seriously," she says.

For the next generation of energy leaders, Moore advises them to "Stay curious and stay grounded. The industry is evolving quickly, but the fundamentals – reliability, safety and customer service – remain constant. Balancing innovation with these core principles is what will ultimately drive meaningful progress."

And as for the road ahead? Moore is clear-eyed but optimistic. "The energy transition is not a linear journey; it's complex, iterative and often uncertain," she acknowledges. "What gives me confidence is the level of collaboration I see across the industry. Utilities, technology providers, academia and research institutes, regulators and other stakeholders are increasingly working together to solve shared challenges." It is that collective effort, combined with a focus on practical execution, Moore believes, will ultimately carry the industry forward.

Ann Moore is Industry Principal, Power & Utilities at AVEVA. She holds a master's degree in electrical and computer engineering from the University of Michigan and previously served as Director of Regional Development for Greater China and India at OSIsoft.