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AMERICAN PUBLIC POWER ASSOCIATION

AFFORDABILITY AND FINANCIAL PLANNING

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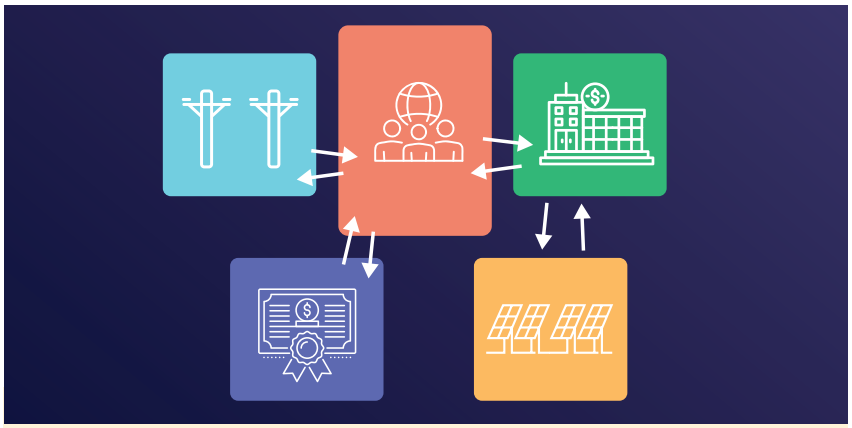

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Powering Strong Communities

The American Public Power Association is the voice of not-for-profit, community-owned utilities that power approximately 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 55 million people that public power utilities serve across the United States and its territories. We advise on electricity policy, grid technology and operations, and workforce development in support of safe, modern, and resilient utilities.

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Public Power's Commitment to Keeping Electricity Affordable

BY SCOTT CORWIN, PRESIDENT AND CEO, AMERICAN PUBLIC POWER ASSOCIATION

For public power, affordability is a core value. Our members work hard to keep prices down for their customers while ensuring they continue to make smart investments in the systems that will serve their communities well for many years to come. As shown in the enclosed 2026 Public Power Statistical Report, public power residential customers continue to have the lowest average electric bill, saving more than $20 a month, or $246 per year compared to customers of other utility types. Yet cost pressures continue around power supply, general inflation, supply chain, and other factors.

While our nonprofit structures are a benefit, maintaining our affordability edge means having to stay fresh on the array of options and innovations available to keep costs low and to structure rates fairly for our communities. This issue of Public Power dives into these innovations to address costs, from how technology and artificial intelligence is being used in utility finance and accounting (see page 22) to strategies for rate design (page 30). It also examines how financing mechanisms uniquely accessible to public power (for which APPA strongly advocated), such as elective pay with tax credits (page 14) and prepay with municipal bonds (page 6), are helping deliver long-term savings for public power customers.

As members work to improve their systems, every choice has an effect on the bottom line. Programs offered by APPA, such as the Reliable Public Power Provider, or RP3, designation, help utilities determine how to specifically prioritize limited resources to maintain operational excellence in safety, reliability, system improvements, and workforce development.

At APPA, we also educate policymakers in Washington, D.C., about how policy and regulatory moves affect affordability or could contribute to uneven cost burdens. We are pushing for reforms at the Federal Emergency Management Agency for quicker reimbursement around disasters, and for reforms to federal permitting of generation and transmission to address supply constraints that are affecting power costs. We also work to ensure you are aware of opportunities for funding your much-needed work, including $1.9 billion for the next round of GRIP grants, announced as part of the SPARK program, and our cooperative agreements with the Department of Energy providing grant dollars to public power utilities.

Thank you for continuing to share the stories included here, and across the national public power network, including on APPA Engage, about how you are navigating economic pressures and delivering value to the communities you serve.

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Financing the Future

How Public Power Is Paying for Infrastructure Projects

BY ADAM PATTERSON, CONTENT SPECIALIST, AMERICAN PUBLIC POWER ASSOCIATION

Photo courtesy Indiana Municipal Power Agency

Public power utilities are overseeing projects designed to incorporate new technologies, diversify their supply portfolios, and meet the demands of load growth and electrification. These capital-intensive, yearslong projects rely on sound financial strategies that provide returns that will outpace their upfront costs and mitigate risk to the community.

Amid changes in the costs to develop or procure various resources, market structures affecting the value of grid assets, and tax policies, utility project financing is a complex endeavor. Public power is securing project funding in ways that are sustainable and with an eye toward long-term affordability for their communities.

Leveraging Storage for Affordability

Utility-scale battery storage has made substantial progress in both affordability and capacity over the past few years. Capital costs for developing battery storage are one-tenth what they were in 2010, dropping from $1,400 per kilowatt-hour that year to nearly $140 per kWh in 2024. This decrease has been driven by advancements in technology and ease of integration. As a result, battery storage was the second largest utility-scale capacity addition in 2024, outpaced only by solar.

Public power utilities are finding energy storage increasingly helpful in supporting overall energy affordability for their communities.

City Utilities of Springfield in Missouri has worked to mobilize capital behind two successive battery storage projects — a 5-megawatt storage installation near City Utilities' Blackman Water Treatment Plant and a 31-MW storage system near the James River Power Station that is scheduled to complete construction later in 2026.

As Jeff Parkison, director of treasury and FP&A, explained, the utility laid out a strategy that paired certificates of participation and tax credits with the leveraging of funding from other projects.

"City Utilities issued certificates of participation along with what I would call pay-go. We also paired the two battery storage projects with the construction of 150 MW of natural gas combustion turbines, doing the financing together for that. Since we needed additional capacity, it made sense to pair those together," Parkison said.

He noted the battery storage projects cohered with Springfield's integrated resource plan, which aims to support the financial and structural viability of the city, the third most populous in the state with a population of 170,000.

City Utilities also made the choice to construct the battery projects based on requirements from Southwest Power Pool to increase reserve margins — to 36% in winter and 16% in summer — in part as a precaution driven by events like 2021's Winter Storm Uri.

Parkinson said an internal power supply task force put together recommendations based on the SPP requirements, which informed its latest budgeting process.

While City Utilities has staggered its construction timelines, it financed both battery storage locations simultaneously. Parkison noted that one of the most important elements behind raising capital for future projects — and setting a timeline for completion — will involve keeping an eye on federal policy and tax incentives.

"Looking forward, our eyes are on the Fed. We were certainly happy that we got the financing completed when we did, especially since we saw changes over the past year to direct pay credits. Thankfully none of those changes so far will materially impact us, so we're focused on completing these projects to meet the deadlines that are within existing legislation," Parkison said.

> **"We were certainly happy that we got the financing completed when we did, especially since we saw changes over the past year to direct pay credits."**
>
> **JEFF PARKISON,** DIRECTOR OF TREASURY AND FP&A, **CITY UTILITIES OF SPRINGFIELD,** MISSOURI

Blackman Water Treatment Plant battery project. Photo courtesy City Utilities of Springfield.

The Right Timing

Over the past decade, the Indiana Municipal Power Agency has developed numerous solar parks across its service area — totaling 54 installations that together have 210 MW of capacity as of February 2026.

IMPA President Jack Alvey said when the joint action agency first began financing and building the solar parks in 2014, using internal cash reserves made the most sense.

As IMPA Chief Financial Officer Chris Rettig explained, the decision to use cash funding was largely a practical one, since each solar park typically comprised 1-MW to 10-MW capacity.

"Given the relatively small size and capital investment, cash funding was [the] most logical and least-cost option with no real negative impacts to the agency's cash flows," Rettig said.

Alvey said IMPA also explored partnership deals with tax equity partners for some of its solar parks to help reduce the cost of construction and to gain access to federal tax incentives. In those arrangements, IMPA designed and built the parks, lending part of the cost of the construction to the tax equity partner, before selling to the equity partner. IMPA then purchased the power from the parks for several years and collected principal and interest from the construction loan. "All in all, this helped us reduce the cost of the park, and we feel we got 50% of the investment tax credit value by doing it that way," he noted.

These contracts included the right for IMPA to purchase the parks back after five to six years, which it has.

With the inclusion of elective or direct payment provisions in the Inflation Reduction Act in 2022, IMPA's financing strategy for the parks changed again.

With direct access to the investment tax credit, or ITC, IMPA again used cash to develop 11 solar parks from 2023 to 2025 and has been filing returns with the IRS to get the full value of the credit. Alvey said his team analyzed options to determine what would deliver the most value for IMPA and its member communities.

"It was not that hard of a decision to make … if our competitors are getting the tax credit for solar investments, we felt that we should get the same value because our customers are paying federal taxes. So, why should our customers be treated differently than a taxable entity's customers?" Alvey said.

IMPA also weighed whether the ITC or production tax credit would deliver more value, ultimately opting for the lower risk of the ITC, as it provides credit on the upfront costs at a point in time, rather than on the continued output, which could change along with tax policy.

While Rettig and Alvey noted the extra work involved in filing the tax returns correctly, using the direct payment mechanism did eliminate the complicated contract negotiations involved with tax equity partner deals. An area they advised other public power entities to pay attention to in filing credit returns was around the prevailing wage requirements, especially ensuring any contractors involved understand and document those requirements correctly.

Alvey acknowledged that IMPA's development of the parks was "lucky, timing-wise," in terms of being able to take advantage of the credits when they were available. He said the current tax policy would have "altered the economics" of the parks for IMPA, but that the solar parks likely would still have been built to continue to diversify its portfolio.

As IMPA considers future areas of grid development, it is looking at how a battery project that came online in December 2025 can offer value and whether further storage systems might help reduce cost pressures, especially in the parts of its territory within the PJM market.

The Richmond Solar Park. Photo courtesy Indiana Municipal Power Agency.

Generational Investments

While certain public power utilities are overseeing expansions to their grid infrastructure, others are raising capital for modernizing their existing grid.

The City of Palo Alto Utilities in California is overseeing a $300 million modernization program designed to accommodate growing electrification in its service area through upgrading decades-old components. This will entail replacing over 1,400 single phase transformers rated less than 50kVA, replacing 56 miles of open wire secondary conductors, and rebuilding several substations serving these areas.

CPAU has been focused on decarbonization and renewables integration, and the utility's Grid Modernization for Electrification Program is intended to provide the structural basis for continuing this work.

"We have some aging equipment and are starting to see older equipment fail at a more rapid rate than some other areas," said Terry Crowley, chief operating officer at CPAU. "We prioritize replacement based on age and system reliability, looking at those areas to determine future capacity needs under rising electric vehicle adoption and home electrification."

Crowley noted many of these choices were made with an eye towards financial practicality, "that is the lowest cost option for us – expanding capacity while we're replacing aging facilities to improve reliability."

CPAU utilities director Alan Kurotori, said investment in grid modernization was determined to be a prudent allocation in light of Palo Alto's high rates of EV adoption and growing number of corporate high-tech and edge data center customers.

"We have one of the highest amounts of registered EVs in the state and growing… We're looking to be strategic and responsive about meeting the load growth of electrification and commercial development while meeting Palo Alto's strong commitment to addressing climate change," Kurotori said.

CPAU has funded the project through a combination of bond financing and internal funding, with the city's well-rated bonds having made this financial strategy particularly sound.

> **"If our competitors are getting the tax credit for solar investments, we felt that we should get the same value because our customers are paying federal taxes. So, why should our customers be treated differently than a taxable entity's customers?"**

JACK ALVEY, PRESIDENT
INDIANA MUNICIPAL POWER AGENCY

"The City of Palo Alto has a AAA rating from both Moody's Investor Services and S&P Global. We're very pleased with our ratings, and plan to fund portions of the grid modernization from rate revenues as well," Kurotori said.

Kurotori described these allocations as an investment in the future, one that would pay dividends through ensuring reliability and affordability, "We see this investment to be generational. It's affecting not only the near-term but will also keep rates affordable here in Palo Alto." Palo Alto's residential rates are nearly 40-50% below neighboring investor-owned utility rates.

To map out potential cost and timeline for complete modernization, CPAU first piloted the upgrades in select areas.

"[The pilot project] informed us how to approach construction and material procurement, and it also gave us a general cost per customer and how much it will take to upgrade all neighborhoods to support electrification," Crowley said.

The Grid Modernization for Electrification Project has received widespread support throughout the greater Palo Alto community, with the project receiving buy-in from major stakeholders largely due to alignment with the city's environmental and service reliability goals.

"We have very strong ties to our community as well as a Utilities Advisory Commission comprised of residents who have a longstanding commitment to Palo Alto. So we were able to engage with stakeholders to vet what things would look like in terms of project financing, and whether it makes financial sense not only for our customers now, but in the future as well," Kurotori said.

While the Grid Modernization for Electrification Project represents a future-looking advancement in the city's grid infrastructure, CPAU staff see the project as a wholly practical one in which the goals align with the broader community's essential values.

"At the end of the day, our main objective is to uphold safe, reliable, environmentally sustainable, and cost-effective service," Kurotori said.

Prepay Bonds Provide Savings on Long-Term Energy Needs

BY JESSICA PORTER, CONTRIBUTING WRITER

Municipal bond-financed prepayment transactions are quickly becoming a top strategy for public power utilities to pay for their power supply needs. At the end of 2025, these financing structures were among the top 10 in the Bloomberg Municipal Bond Index. A record $580 billion in municipal bonds was issued in 2025, and many of the major issuances of the new money bonds in the electric sector were for prepays. In the first half of 2025, of just over $9 billion in power-related new money bond issuances, about $7 billion were for prepays.

The Almond 2 Power Plant. Photo courtesy Turlock Irrigation District.

What Are Prepayment Bonds?

Prepay municipal bonds are used to provide the upfront capital for prepay transactions, which in turn secure a long-term supply of electricity or natural gas. The transactions make financial sense because the bonds are exempt from tax and so are issued at a lower rate of interest than taxable debt. These cost savings are generally passed on to customers. Prepay transactions have been around for decades but are growing in volume and complexity.

Parties to these transactions include:

- The customer, which is the public power utility that ultimately receives electric power or natural gas from the supplier.
- The issuer, generally a "joint powers authority," which is a financing authority that issues the bonds and manages the deal structure.
- The supplier, which is a power developer, generator, or natural gas supplier.
- The bank, which takes receipt of the bond proceeds in exchange for making payments to the supplier.
- The investor, which buys the bonds and provides capital for the transaction.

In a simpler variation, a public power utility is the issuer instead of a joint powers authority.

Prepay bonds specifically fund the purchase of energy commodities like natural gas or electricity, not power infrastructure. The condition of prepay bonds is that the

> **"At different times, the market takes different-size deals better. It might be a market that can take a lot of prepay debt, or it might be a time when smaller deals are better."**
>
> **FRED CLARK,** PRESIDENT AND CEO, **ENERGY SOUTHEAST,** ALABAMA

ultimate consumer of the product must be customers of a municipal utility, according to Peter Thompson, executive vice president and chief operating officer of Energy Southeast, a joint action agency based in Montgomery, Alabama.

Prepayment bonds allow municipal utilities to achieve discounted rates on a long-term energy supply. The bonds include final maturities that typically are 30 years, with shorter tenders often between five and 20 years. The shorter tenders optimize borrowing costs, while the longer maturity improves the bond's market discount tax treatment, according to Sterling Capital.

Utilities can alternatively secure power supply via power purchase agreements. What's different with prepay transactions is that they allow a utility to lock in a supply while taking advantage of the tax-exempt benefit of municipal bonds.

"Utilities have achieved the best economics they could through PPAs, but there are greater discounts and savings on energy itself through prepay bonds," said Fred Clark, president and CEO of Energy Southeast.

An issue drawing attention is that while prepay transactions can help public power utilities achieve discounts on power supply costs, the other parties also derive benefit from the transaction. For example, under a prepay transaction, a bank typically obtains bond proceeds from the issuer in exchange for making prepayment payments to the supplier. These payments are generally equal to the amount the bank would have to pay if it — and not the issuer — had borrowed the money, i.e., its discount rate. The value to the issuer is that for the price of paying off their tax-exempt interest, the bank is making payments to the supplier equal to what would be a taxable interest rate. The advantage to the bank is that it is not limited in how it invests the bond proceeds and so can achieve a rate of return higher than its discount rate. A 2022 article in *Forbes* about prepaid bonds noted how the large financial firms involved in brokering the issuances benefit from the tax-exempt status of the bonds.

The Rise of Prepay

One of the biggest issuers of prepay bonds in recent years is the Southeast Energy Authority. (Note: SEA and Energy Southeast are different entities). According to its website, from 2021 until October 2024, SEA executed eight prepayments totaling $4.71 billion. In 2025, it was involved with some record-setting deals with public power entities, including a $675 million transaction that involved multiple utilities across the U.S. and a nearly $2.7 billion transaction involving Salt River Project in Arizona.

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Other large deals include a nearly $1 billion transaction that the New York Power Authority established with the New York Energy Finance Development Corporation. The largest issuer in 2025 was the California Community Choice Financing Authority, which leveraged deals for community choice aggregators in the state.

The rise in prepay bonds is driven by growing energy demand, favorable interest rates, and trends in power generation.

"As costs go up, due to increases in demand and loads, utilities are searching for ways to save money and reduce costs," Clark said.

Additionally, interest rates have been high over the past 10 years, a key component to gaining the benefits of prepay bonds. When interest rates are low, the savings aren't as significant.

"When you bring a deal to market, the market moves constantly, and the difference between taxable and tax-exempt is different every day," Thompson said.

"That's what makes this unique; it's something you already will buy," said Brian Stubbert, assistant general manager of financial services and chief financial officer at Turlock Irrigation District in California. "If you buy natural gas or renewables, you already have these expenditures, and it's a way of helping ratepayers receive the benefits of transactions you will enter into anyway."

Prepay bonds first hit the market in the 1990s, leveraged primarily to finance natural gas purchases. In 2003, the IRS issued guidance allowing prepay bonds to be used for electricity as well, including renewables. That guidance opened the door to utilities in states like California that are moving away from fossil fuels and relying more heavily on electricity.

In those states, uncertainty existed about whether natural gas would be permitted in the future, so those utilities were hesitant to participate in the long-term contracts required by prepay structures. The guidance assured utilities they can purchase natural gas, electricity, or a combination of both using prepay structures.

Randy Howard, general manager of the Northern California Power Agency, noted how he had been involved in some of the largest prepay transactions at their inception near the turn of the 21st century, when he was with the Southern California Public Power Agency and Los Angeles Department of Water and Power.

At that time, he said, the strategy to use prepay bonds stemmed from public power being blocked from direct access to tax credits on renewable projects.

"We had owned hydro, we had owned coal, we owned gas plants, but we really weren't owning a lot of renewable facilities. Yet, our ratepayers were seeing substantial benefit on some of these facilities that we had owned almost 100 years," he said, noting that the true value related to these assets was from the land they sat on, the interconnection to the grid, and the resources produced.

Howard said that the prepays allowed utilities to manage the risk upfront and offered an opportunity to own the assets later, a benefit both to the more nascent solar industry and to the utility being able to continue to deliver value to its community.

"So, we prepay, and if something were to happen with the developer or the project, we had great step-in provisions where we could take it over, but we also had buyout options associated with that transaction. It reduced our cost up front for the resource, but it also secured some risk elements that we could better manage."

Compared with doing power purchase agreements, Howard said prepay arrangements have some higher upfront risk, but can provide better negotiating opportunities than a PPA without a prepay provision.

While he acknowledged that the market has evolved since some of the early deals, Howard said he "would never do a prepay on a renewable project that his agency no interest in eventually stepping into" or operating directly under a default scenario.

Saving Today, Funding Projects Tomorrow

TID, a public power utility in Turlock, California, sought the expertise of a financial advisor when it began looking into prepay arrangements, both to help navigate the nuances of prepay bonds and to determine whether they were the right approach for the utility.

TID finished its first deal in early 2025, achieving savings of $93.3 million on its natural gas purchases over 10 years. After 10 years, additional bonds will be issued to achieve additional savings, and the utility will have the option to convert from natural gas to electric and renewable energy.

Though the arrangement is a 30-year contract, it's common for the bond length to be less, with additional bonds negotiated at market rate.

The second deal began in February 2026, with TID achieving savings of $48 million associated with its renewable energy purchases over eight years. Similar to the first deal, additional bonds will be issued after eight years. It includes two existing PPAs, one for wind and one for solar. For both transactions, TID worked with Goldman Sachs.

Goldman Sachs noted that gas prepay bonds surpassed $31 billion in 2025, a record year. It gave two primary reasons for increasing utility interest in the mechanism: lower borrowing

> **"Talk to a utility that has done prepay and start gathering information to see if it's right for your utility. This is a mechanism other industries don't have; Let's use all the tools in our toolbelt to lower costs."**
>
> **BRIAN STUBBERT,** ASSISTANT GENERAL MANAGER OF FINANCIAL SERVICES AND CHIEF FINANCIAL OFFICER,

The Tulomne Wind Project. Photo courtesy Turlock Irrigation District.

costs and rising energy prices. Still, the terms that will be most favorable to both utilities and the financial institutions involved in the issuance can change quickly.

"When you go to market, you look at what duration investors will invest and what time period gives the best savings," Stubbert said. "We had an eight- and 10-year option on the first deal, and the 10-year gave the best savings. I wanted that again for the second deal, but people were looking for six to eight years at that time."

TID plans to use the savings from both transactions to offset future rate increases and pay for the construction of large capital projects planned over the next five to 10 years, like new substations and increased capacity at existing substations, additional transmission and distribution lines, new transformers, and upgrades to generation facilities.

"Anybody who can use these should really strongly look into them," Stubbert said. "The biggest advice I can give is to start the process and don't drag your feet. In a time when costs are going up, it's a good feeling to provide real savings to ratepayers."

Achieving Deeper Savings

Energy Southeast began leveraging prepay bonds approximately eight years ago after being approached by Morgan Stanley, which demonstrated the regulatory requirements for prepayment.

It decided to wrap existing PPAs into prepay arrangements, resulting in $2 billion in bonds and $100 million in savings over the first seven years of the deal, which was $14.5 million annually. Those savings proved the worth of prepay to Energy Southeast, and it continued partnering with public power utilities on prepay deals.

It recently worked with Morgan Stanley to underwrite $1 billion in bonds for CPS Energy in Texas, which leveraged the deal to access additional solar and other renewables for its power supply. The proceeds were given to Energy Southeast, which

prepaid for the power. CPS Energy will purchase the power from Energy Southeast over the next 30 years.

The prepay structure is allowing CPS Energy to save 8% on the power it would otherwise have purchased directly from the developer through a PPA. Energy Southeast also recently worked with Florida Municipal Power Agency and Riviera Utilities in Alabama to enter existing PPAs into a prepay arrangement with Goldman Sachs as the underwriter.

It includes four components rolled into one prepay arrangement to create a $430 million deal. Transactions of all sizes can enter prepay arrangements.

"At different times, the market takes different-size deals better. It might be a market that can take a lot of prepay debt, or it might be a time when smaller deals are better," Clark said. "We can put a number of deals into one transaction."

Howard sees some similarities between the renewable project prepays he has been involved with and some of the natural gas prepays occurring today but sees the latter as more of an exercise in arbitrage and price hedging than a means to buy out a resource. He credited Energy Southeast for developing a model that makes it easier for public power utilities to get involved in prepay transactions.

However, Howard sees prepays as mostly being valuable for larger projects.

"It's a little costly to put together, so you really want a large enough project to ensure that you're going to optimize the benefits," he said, explaining why the transactions are often connected to larger utilities or joint action agencies.

Getting Leadership on Board

Since many utilities are new to prepayment bond arrangements, the biggest hurdle to entry often is education.

"Each utility has to get its governing body to approve the contract, and that's the hardest lift," Thompson said. "It's a 30-year contract, which sounds scary. You can do shorter structures, but 30 years creates more savings."

Prepay bonds are considered nonrecourse debt. The utility pledges to purchase a commodity it would purchase regardless of financing structure, and it doesn't impact revenue or require a rate raise. If the counterparty doesn't deliver the agreed-on power, the utility isn't on the hook to pay it. In traditional bond arrangements, the utility pledges revenue. If it can't make a bond payment with a traditional bond, it is required to raise rates until it can make the payment, according to Stubbert.

TID held workshops for its board members about prepay bonds. Board members asked questions to understand the structure and potential risks and requested that independent counsel evaluate the risks. TID worked with auditors to better understand how prepay would be treated in its financial statements.

"The one disadvantage is the psychological impact of adding that much debt onto our books. Over the two deals, approximately $1.7 billion in principal was added to our consolidated balance sheet, which is more than three times that of our traditional bond debt," Stubbert said. "So the Board wanted to understand the type of transaction and the impact it would have on TID."

Another hesitation in entering these arrangements is estimating the load over such a long period of time. There's no risk of financial loss if significant load changes occur due to protection mechanisms in the arrangement, but the utility won't achieve the savings expected.

"The risk is if you have a large customer that leaves, or if a lot more customers install solar or other behind-the-meter generation, and then your load drops," Stubbert said. "It's not a loss, but you don't get the savings."

TID managed this risk by purchasing power under a prepay arrangement that is below the threshold of what it estimated the load to be over the 30-year period.

Stubbert encouraged public power utilities to look into whether prepay structures make sense for their energy purchases.

"Talk to a utility that has done prepay and start gathering information to see if it's right for your utility," Stubbert said. "This is a mechanism other industries don't have; Let's use all the tools in our toolbelt to lower costs."

UNDERSTANDING PREPAYMENT BONDS

Public power is increasingly looking at prepayment transactions to get savings on power supply. While these transactions can take different forms, here's a quick overview of how they typically work, including each party involved and how they benefit from the transaction.

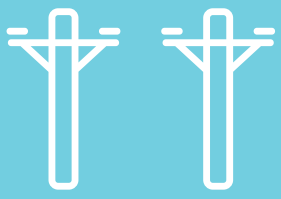
The transactions can be complex and involve a third-party issuer, where a public power utility is the customer. Public power providers can also take a more active role in these transactions, serving as both the customer and the issuer.

Who's Involved

Customer

The utility/joint action agency buying long-term power supply.

Savings on power supply



Issuer

The go-between entity (typically a joint powers authority) that issues the bonds, assists in transfer of power to customer, and transfers bond proceeds to the bank.

Compensated for developing and managing the transactions

Bank

Makes payments to supplier and transfers power to issuer.

Receives and invests bond proceeds

Bondholder

Purchases bonds.

Repayment of principal, with interest

Supplier

Generates and sells power to bank.

Assured, long-term purchase of output

How to Modernize Without Breaking the Budget

Why scaling is a modernization model built for public power budgets

The imperative to modernize is clear. Yet knowing the need and meeting it are two different things. Public power utilities today face growing pressure to modernize aging grids at the very moment federal support is being reduced. Recent cancellations of billions of dollars in clean energy and grid improvements have left utilities balancing essential modernization needs against shrinking federal and state resources.

For most utilities, that means the question isn't whether to modernize, but how to deliver improved reliability and resilience within genuine constraints. For utilities caught between run-to-failure legacy practices and the pressure to transform, the answer lies in scaling — starting with where you know you need help most, proving the value, then expanding systematically as results and budget can justify further commitment. It is a grid modernization strategy designed for how utilities actually operate.

Lateral protection as a case study

Consider overhead laterals — often the most outage-prone segments of the distribution system. Conventional fuses do their job, but they cannot distinguish between a temporary fault and a permanent one. A squirrel, a wind-blown branch, a momentary contact — any of these will trip the fuse, and customers sit in the dark until a crew arrives to replace it. Multiply that across hundreds or thousands of laterals, and the cumulative impact on reliability metrics, O&M costs,

customer satisfaction, and overall resilience adds up fast.

Single-phase reclosers change the equation by bringing fault-testing to the lateral level. Devices like S&C's TripSaver® reclosers automatically restore power after temporary faults before they become sustained outages and isolate permanent faults to minimize outage impact. They can mount in cutouts, require no communication infrastructure to deliver value, and can be deployed easily and incrementally.

- **Start with what you know.** Most utilities already know their worst-performing laterals — the ones that generate repeat truck rolls, the feeders that drive SAIFI and SAIDI numbers, the areas where service calls come from most. That is enough to start a pilot with devices deployed in targeted locations.
- **Prove your case.** When you strategically place TripSaver reclosers in areas of your grid where they are likely to operate, you'll have the data you need to build your business case within three to 12 months. Data from TripSaver reclosers can be easily collected using sensors, meters, or by pulling device analytics to measure impact and show the value of expansion.
- **Expand systematically.** This approach expands with you. You can start with a handful of devices on your most troubled laterals and scale from there. As you gather performance data, each deployment informs the next. Over time, you build not just a more reliable grid, but a deeper understanding of where future investments will deliver results. Because these devices reduce truck rolls, your crews spend less time chasing temporary faults and more time on proactive maintenance and system improvements.

Alabama Power proved the model

The utility began with a pilot of 20 TripSaver® II Cutout-Mounted Reclosers in the Birmingham area. After one year, those 20 devices saved nearly 107,000 customer minutes of interruption and avoided more than $15,000 in O&M costs. That initial success justified an expanded deployment of 100 units across the state.

The results were striking: a 70% improvement in SAIFI and 57% improvement in SAIDI on protected laterals. Customers who had been experiencing sustained outages more than twice a year saw that drop to once every three years. With proof in hand, Alabama Power committed to installing more than 1,500 reclosers annually over 10 years as part of its grid modernization program.

Flexibility is the point

Grid modernization doesn't have to mean rebuilding everything at once.

When less capital is available, incremental investments with compounding benefits are crucial. What makes this approach powerful is its adaptability. It bolsters your system where it's needed most, proving value at each step, and scaling as conditions warrant. And every investment in reliability and resilience has a direct positive impact on the community you serve. That is a modernization strategy built for today's utilities.

Learn how S&C's lateral protection solutions can help you scale your modernization strategy and build toward a more resilient grid at sandc.com/lateralautomation.

How Technology Is Transforming Utility Finance and Accounting

BY JOHN EGAN, CONTRIBUTING WRITER

Emerging technologies, including artificial intelligence, are changing the way utilities conduct financial planning and accounting

In finance and accounting, utilities typically have relied on spreadsheets to reconcile accounts, track budgets, project revenue, and measure construction work in progress. Many finance and accounting tasks can be time-consuming and mind-numbing. Today, technology, including artificial intelligence, is changing that — speeding up some tasks and elevating others to forward-looking, value-added functions.

Finance and accounting typically emphasize historical reporting over forward-looking analysis, said Russ Hissom, senior manager for energy and infrastructure at Baker Tilly Advisory Group LP, a large U.S. tax, advisory, and assurance firm.

Until now, utility financial analysts and accountants have had to spend a lot of time cleaning up and standardizing financial data, which sometimes arrives in a less-than-complete or inconsistent format. Each month, a lot of manual data massaging has been needed to put information into acceptable templates for board and council meetings.

The gradual embedding of AI functionality into workplace software packages means that the future will not look like the past, Hissom said. He spoke on this topic at the American Public Power Association's 2025 Business & Financial Conference, and is scheduled to speak again at the Accounting and Finance Virtual Summit in April.

"AI tools are helping utilities maximize the value of the financial information they have," Hissom said. Those tools can quickly automate reconciliations for banks, subledgers, inventories, and project costs, recognize data patterns, and process documents such as invoices.

"You'd be surprised how many times a utility orders 100 poles and 80 are delivered," he said. Those gaps must be reconciled, and doing so has historically involved tracking those costs in separate spreadsheets or systems that can't be easily integrated.

In some instances, Hissom said, public power utilities are using AI to prepare rudimentary rate-case materials that will be reviewed by staff. Best-practice utilities also are using AI to integrate formerly separate processes for financial planning, accounting, load forecasting, revenue recognition, and other functions.

He said that a variety of platforms, including those from Workiva, BlackLine, UiPath, Automation Anywhere, Power BI, and Tableau, are transforming finance and accounting functions including financial reporting, Federal Energy Regulatory Commission filings, board reporting, monthly closes, account reconciliations, transaction matching, accounts payable, and tracking key performance indicators.

"AI is very useful at assembling and analyzing data, but it is unable to exercise judgment," said Hissom. "Deploying AI is like hiring an intern: useful for some tasks, but the work has to be checked and confirmed."

Room to Improve

Bart Miller, the chief financial officer for Heber Light & Power in Utah, sees potential for technology to reduce a lot of the manual work involved in utility accounting.

"It can be very time-consuming to convert data into the formats required by a utility's systems," he said. "Typically, that is not a value-added activity." He said he recently spent about six hours over three days manually manipulating data so that it

aligned with the utility's budget software.

"Right now, utility finance and accounting platforms are clunky, but providers of those platforms are being pushed hard to modify their systems for our market, and they are responding," Miller said.

A growing number of utilities are using software with AI capabilities to automate their functions and processes. Some have been using AI tools embedded in Excel to project energy use curves and to help prepare graphs and presentations.

Going forward, Hissom and Miller agreed that providers of existing finance and accounting systems will be forced to broaden and customize their systems to meet the needs of the large number of small and midsized utilities that could become customers. That process is underway, but it's just getting started.

"Once the big dogs in the utility industry adopt it, it will spread," Miller predicted. "Right now, the platforms are not purpose-built for utilities."

Heber Light & Power serves about 16,000 customers.

"AI is very useful at assembling and analyzing data, but it is unable to exercise judgment. Deploying AI is like hiring an intern: useful for some tasks, but the work has to be checked and confirmed."

RUSS HISSOM, SENIOR MANAGER FOR ENERGY AND INFRASTRUCTURE, **BAKER TILLY**

Removing Silos

Hissom believes AI will have a dramatic positive benefit on public power utilities across a range of departments, not just finance and accounting.

"There are opportunities for dramatic increases in productivity across the utility enterprise, akin to the introduction of computers in the workplace, spreadsheets, the internet, and [enterprise resource planning] systems," he said.

"The biggest benefits to utilities will come from analytics, such as customer energy-use projections, inventory management, and calculating how electric vehicle charging will impact the local distribution system," predicted Miller.

These functions are closely related to financial planning, though they often reside in different departments. AI can help tear down those internal silos and drive organizational change. "Right now, we're just getting started," said Miller. "As an industry, most of us are trying to figure out how to crawl, while some are walking and a select few are running. If I had to liken it to a sport, I'd say we're at the opening kickoff in a football game."

Need for Data Security Limits Use

Hissom and Miller agreed that using AI on locally hosted, internal applications for finance and accounting is fine because the data stays in-house. However, public platforms such as ChatGPT, Claude, or Gemini, which add users' work to their cloud-based large-language models, are a no-no, at least for now, because they exist externally and thus are subject to hacking.

> **"Utility finance and accounting platforms are clunky, but providers of those platforms are being pushed hard to modify their systems for our market, and they are responding."**
>
> **BART MILLER,** CHIEF FINANCIAL OFFICER,
> **HEBER LIGHT & POWER,** UTAH

"Data security is so important to utilities," said Hissom. "Utilities have access to a lot of sensitive data. You can't have a customer's personally identifiable information like their Social Security number, banking information, and passwords out there floating in the cloud."

"The opportunities for malevolent actors to use or sell that information is why utilities, banks, credit card companies, and government agencies operate under strict data-security protocols."

Hissom said utilities would have to purchase a special enterprise license from those software companies to make sure their data is not being used to train the companies' AI models. "As long as the data stays in-house and out of the public domain, it's okay."

"There is a huge library of public data about geography, locations of physical assets, climate, census tract demographics, disposable income, property values, and energy affordability. All of those data streams affect a utility's creditworthiness and utility financial planning."

ANDREW TERAS, HEAD OF PRODUCT STRATEGY (AMERICAS), **INTERCONTINENTAL EXCHANGE**

Miller agreed. "There is a lot of anxiety about using cloud-based applications because of data security issues."

Miller said he has used AI-enabled software to perform financial planning and analysis, though he worried about its data security.

Planning in a Changing Risk Environment

Outside of utilities, financial planners are using technology to better understand and forecast a variety of financial pressures and risks surrounding energy infrastructure and utilities.

For example, Intercontinental Exchange has built a powerful platform that uses algorithms and various historical data streams to provide forward-looking risk assessments for utilities and other types of bond issuers. Bond analysts and asset managers are using the Intercontinental Exchange's Climate Analytics Platform, or Intercontinental Exchange's CAP, to gain a more comprehensive understanding of utilities' exposure to physical hazards like wildfires, hurricanes, and floods.

Utility financial planners can use this platform to better understand their own changing risk environment as well as the way the investment community views utility projects.

"Public power utilities that want to stay abreast of the way the financial community assessment of risks is changing have been able to gather that insight from our platform," said Andrew Teras, ICE's head of product strategy (Americas).

The platform turns qualitative assessments, such as, "We're a municipal utility located in California, so we may have a wildfire affect our service area at some point in the future," into more of a data-driven and long-term probabilistic outlook, such as, "Within our service area, the estimated percentage of property value at risk from wildfires may be as high as X%."

"There is a huge library of public data about geography, locations of physical assets, climate, census tract demographics, disposable income, property values, and energy affordability," said Teras. "All of those data streams affect a utility's creditworthiness and utility financial planning. Our platform draws on all of those data sources and more to provide users with better insight into the specific risks facing bond issuers."

Utilities could use that intelligence to double-check that they are fully insured against wildfires or other extreme events, or to calculate how a planned price increase affects the affordability of their services compared to peers. ICE CAP also has tools to assess the economic profile of a given census tract.

One metric of the changing risk environment facing utilities is the rising impact of weather disasters tracked by the U.S. government. The numbers show an unmistakable upward trend. The rolling five-year average impact is about $150 billion per year, up sharply from what it was 10, 20, or 30 years ago.

And the number and value of those disasters align with documented gains in global average surface temperatures, as tracked by the National Oceanic and Atmospheric Administration.

Bond analysts and bond investors are, in fact, using climate data and a variety of other data to better assess the creditworthiness of utilities, Teras said.

"There has been an increasing trend to rigorously measure risks and benchmark them, both quantitatively and qualitatively," he continued. "The risk-assessment landscape has changed considerably in recent years. Increasingly, we are able to quantify risks that once were only assessed qualitatively."

Hard quantitative metrics, such as the age of a utility's assets, its rate of customer growth, and average number of days customer are behind in their bill payment, increasingly are being combined with qualitative metrics like risk profiles to provide the financial community with a more comprehensive understanding of all the risks that could threaten a utility's ability to repay a bond.

Public Power Leaders: **Brian Skelton**

Brian Skelton has served as CEO of Riviera Utilities in Foley, Alabama since May 2024. His career in public power began at Memphis Light, Gas, and Water in Tennessee in 1985. His wealth of experience across numerous municipalities includes serving as the president of Tullahoma Utilities Authority in Tennessee, general manager of Bowling Green Municipal Utilities in Kentucky, and general manager of Opelika Power Services in Alabama. Skelton holds a Bachelor of Science in electrical engineering from the University of Tennessee and a Master of Science in engineering management from Christian Brothers University in Memphis. He was a 2012 recipient of the American Public Power Association's James D. Donovan Individual Achievement Award and a 2015 recipient of APPA's Kramer-Preston Personal Service Award.

WHAT BROUGHT YOU TO YOUR CAREER IN PUBLIC POWER?

I participated in the 4-H electric project in junior high and high school, and my uncle was a lineman for the local electric cooperative where I grew up, which gave me some exposure to the industry, though I didn't head off to college knowing I was going to work for a utility. I was pretty good at math, so I studied electrical engineering. I went across the state to the University of Tennessee at Knoxville, which offered a cooperative education program where you could work five quarters before earning your degree, which gave me the opportunity to work for Memphis Light, Gas, and Water during college.

After I graduated, I spent about 12 years in various engineering and midlevel management positions at MLGW. I want to give credit to MLGW for being a great place to learn. I realized early on I wanted to manage people rather than just do engineering. Now, 41 years later, I've worked at five municipal utilities and have been fortunate to be the CEO of four of them.

WHAT HAVE YOU ENJOYED MOST ABOUT WORKING IN PUBLIC POWER?

I would say the people and the ethics. Public power is there to serve, not just make a paycheck. We of course want to make good money and pay our employees fairly, but we also want to save money and keep our rates low. It's refreshing to focus on making the right decisions for your customers and your utility and not be driven by pressures that investor-owned utilities face, where you need to increase returns for stakeholders. The ethics in public power are superb, and people are here for the right reasons. I've worked across multiple locations, and each utility is motivated to serve its customers and keep rates low.

HOW WOULD YOU DESCRIBE YOUR LEADERSHIP PHILOSOPHY?

One of my big priorities is to have an open-door policy. I always welcome employees to engage me and come visit my office, whether they just want to say hello or have a concern. We have a very small leadership team at Riviera Utilities — my direct leadership consists of a COO, a CAO, and a CFO. They're very competent in what they do, and while I aim to provide guidance and oversight, I also try to get out of the way and let them lead their areas.

Riviera tends to promote a lot from within and build people up, and they hadn't brought anybody into a leadership role with extensive experience in other utilities for a long time, if ever. So, I've tried to bring in new ideas while respecting the existing culture.

WHAT ARE SOME OF YOUR PLANS AND PRIORITIES FOR RIVIERA UTILITIES?

Managing growth is one of our biggest priorities. We're also looking to expand our electric vehicle charging and are actively working with the communities we serve. [The cities of] Daphne and Spanish Fort are both on Interstate 10, so they have a lot of traffic there and are high priority for us. We have two fast chargers here at our headquarters in Foley that seem to be used more today than they were just two years ago when I first arrived at Riviera.

Riviera has essentially completed a fully functional, two-way AMI system. We put in remote disconnects on all our 200 residential and small commercial meters, which will allow us to disconnect and reconnect customers with a keystroke. It will also give us much more information at our fingertips. When customers have questions about their bill, we'll have 30-minute increment breakdowns on their electric usage we can share with them.

We're working on plans to put in a kiosk system in our two locations in 2026, which would allow customers to make credit card or cash payments 24 hours a day. We'd also like to add prepay electric to allow customers that don't have the ability to make large deposits sign up for electricity and pay as they go.

WHAT ARE YOU PROUDEST OF HAVING ACHIEVED AT RIVIERA UTILITIES SO FAR?

Working to get our employees competitive compensation. We're growing rapidly as a utility — we have about 60,000 electric customers right now and are on target to build a new substation every three to four years. This is in addition to 20,000 water customers, 9,000 wastewater customers, and 8,000 natural gas customers. Our board was very supportive in allowing us to bring salaries up to where our employees were being paid fairly for their service. Riviera is fortunate to have a team of really good employees, and I'm proud we've been able to ensure they receive the support they need as they continue putting in the hard work to modernize and expand our grid.

Maintaining Affordability

How Public Power Utilities Deliver Savings Amid Rising Energy Costs

BY BETSY LOEFF, CONTRIBUTING WRITER

Photo by Gravity Group, courtesy of Harrisonburg Electric Commission, Virginia

It's been more than a year since the U.S. Energy Information Administration reported that electricity rates have outpaced inflation since 2022, and the agency predicts that trend will continue through 2026. The higher bills have been a focus of local elections and spurred public interest in public utility commission proceedings.

With a reputation for affordability, public power providers face substantial challenges to keep rates down and equitable. Amid mounting economic pressures, utilities are responding with a closer look at ways to manage demand, developing new rate structures for emerging loads, and staying in tune with their financial health indicators to find potential savings for customers.

Strategies for Keeping Up

"The public power sector is facing multiple, simultaneous pressures," said Amanda Guci, senior manager for Raftelis, a management and consulting firm that advises local governments and utilities. One major pressure is the scale of capital investment across power systems nationwide, from system upgrades to new generation and transmission facilities. Guci noted industry estimates project these investments to reach up to $1.4 trillion through 2030. These investments include replacing aging infrastructure and meeting accelerated load growth, particularly from data centers. At the same time utilities have these development needs, they are facing increased costs for materials, equipment, and construction.

Given the considerable time, cost, and effort of constructing new plants and infrastructure, Guci noted that some utilities are turning to load flexibility strategies to manage the high demand placed on the grid.

In Virginia, the Harrisonburg Electric Commission uses load flexibility as a day-to-day strategy for managing the coincident-peak-based demand charge it pays to Dominion Energy, its generation supplier.

"We have several C&I customers that we have on load reduction rates, and some of them are interruptible," said Brian O'Dell, HEC's general manager. "That helps us keep our peak charges down each month."

So does conservation voltage reduction, which is when the utility brings down distribution system voltage to the lower end of the allowable range to reduce energy consumption, peaks, and line losses. The approach typically cuts usage by 1% to 3% without affecting customer service.

O'Dell said advanced metering infrastructure helps the utility with load studies and verifying that customers on interruptible rates are participating in peak reduction.

Guci gave the example of an investor-owned utility in the Pacific Northwest that partnered with a company specializing in AI-driven forecasting and load modeling. By optimizing flexible resources like batteries and onsite generation, she said the utility was able to avoid building new infrastructure and the initiative "freed up more than 80 megawatts for data center interconnections."

Guci noted that while such approaches represent a promising direction for the power sector, they have not yet achieved widespread implementation.

"With all the changes that are happening within the industry, things look very different from one year to the next. Now, we are recommending cost-of-service studies every three to five years, supplemented by annual financial planning updates."

AMANDA GUCI, SENIOR MANAGER, RAFTELIS

Regular Reviews

Another strategy Guci recommends to keep rates fair and equitable (and one she sees utilities increasingly adopting) is conducting more frequent financial plans and cost-of-service studies.

"We historically recommended cost-of-service studies on a five-year cycle. These studies explore how costs are allocated across customer classes based on the demand they place on the system," she said. "With all the changes that are happening within the industry, things look very different from one year to the next. Now, we are recommending cost-of-service studies every three to five years, supplemented by annual financial planning updates." The same principle applies to long-range financial planning. "It is essential to monitor how projections compare to actual results on a year-over-year basis."

California's San Francisco Public Utilities Commission is already doing financial updates annually, and actual rate calculations happen annually, too, said Matt Freiberg, SFPUC's rates manager. "We take a look at billing data every year, and we calculate an effective rate for each rate tariff. And then we look at the overall load for each of these rate tariffs, and we project out our revenues using those effective rates. We reevaluate every year, and it's a big reason why we only adopt a one-year rate at a time," he said.

"San Francisco also has a rate fairness board, which is a group of people that represent city departments as well as representatives from different customer classes," said Mike Hyams, deputy assistant general manager at the PUC. That team — plus anyone from the public who attends the Commission's multiple meetings each year — also informs the city's ratemaking.

New Approaches for New Loads

As new technologies put pressure on utility rates, new ratemaking approaches are emerging.

"When EV charging stations first started coming online, they were typically classified as standard commercial rates," Guci said. "However, EV charging stations — especially the DC fast chargers — spike the demand of the system while they're charging. Their load profile does not align with that of a typical commercial customer, so utilities need to establish an appropriate demand charge and/or an appropriate kilowatt-hour charge."

O'Dell said regulators in Virginia have recognized the large loads data centers bring. Last November, the Virginia

"We have a lot of diversity in our load. We have a lot of industry, residential, and commercial loads, as well. Our load factor tends to run relatively high, so our overall cost of power on a kilowatt-hour basis benefits from that."

BRIAN O'DELL, GENERAL MANAGER,
HARRISONBURG ELECTRIC COMMISSION, VIRGINIA

State Corporation Commission approved a new, mandatory "GS-5" rate class aimed at high-load customers. The new rate class, which takes effect in January 2027, requires high-load customers to cover 85% of their contracted distribution and transmission demand, as well as 60% of the generation demand they place on the system.

Another emerging trend Guci sees is "rate structures designed to screen out uncertain projects" on data centers and other large load customers. With AI-driven data center proposals rapidly expanding interconnection queues, utilities are implementing large-load tariffs designed to ensure that only projects that are sure to go online get into the queue, she said.

An APPA report, What Public Power Needs to Know About Serving Data Centers, includes a summary of how public power utilities have structured rates for large loads including data centers. Santee Cooper, a public power utility with 208,000 customers in South Carolina, has implemented a large-load tariff and requires customers to pay a deposit to cover capital costs and line extensions. The large-load rate includes a monthly customer charge, plus a demand and coincident-peak demand charge, a seasonal time-based energy charge, and a peak power charge.

Santee Cooper also expects large-load customers to pay for delivery-point and transmission construction costs, network

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> **MIKE HYAMS,** DEPUTY ASSISTANT GENERAL MANAGER,
> **SAN FRANCISCO PUBLIC UTILITIES COMMISSION,** CALIFORNIA

upgrades, and any additional facilities needed. In addition, large-load customers must sign a service agreement, ensuring that they won't drop load below 50,000 kW and will stay in the system — at least financially — for 15 years.

Yet another trend is time-based pricing, especially rates that incentivize overnight EV charging to help utilities improve load factor and shift charging load to off-peak hours.

Customer Impact

Rates may be rising overall across the U.S., but both Harrisonburg and San Francisco have reduced costs for customers in recent years.

Harrisonburg's rates have historically been on the low side. According to APPA's latest Average Revenue per Kilowatt Hour report, in 2024, the utility's average residential rate was 15% lower than Virginia's public power average, 22% lower than the state's IOU average, and 17% lower than the rate residential customers were paying to cooperatives.

That same year, HEC saw a 5% increase in its wholesale power costs. Fortunately, the fuel-cost component of the utility's rates from Dominion Energy dropped. "By the time we got our fuel factor adjusted, it more than offset what our base rate increases would have been for the year," O'Dell said. The result was a $5.45 monthly reduction in power bills for the average residential customer.

O'Dell modestly maintained that this rate decrease was mechanical, and benefitted from running a system with a high load factor. "We have a lot of diversity in our load. We have a lot of industry, residential, and commercial loads, as well. Our load factor tends to run relatively high, so our overall cost of power on a kilowatt-hour basis benefits from that," he said.

The utility also has a highly efficient staff. There are only 41 employees for the utility, which serves 56,000 residents (21,800 meters) spread over 18 square miles. Its service area includes James Madison University.

Good financial stewardship played a role in SFPUC's ability to lower rates this year for CleanPowerSF, the community choice aggregator serving the city. The CCA, combined with the city's Hetch Hetchy hydroelectric plant, provides more than 75% of the electricity consumed in San Francisco.

Last year, SFPUC staff saw a rate increase on the horizon due to one of the fees charged by Pacific Gas & Electric, the IOU that provides the city's distribution infrastructure. "We had been monitoring what was going on with this fee, and we knew several months in advance that it was going up because of changes in the market prices for various power supply products," Hyams said. After starting to prepare a rate action, the city found out that PG&E's fee was rising 400%.

The number is a big one, but that impact was significantly reduced when SFPUC decided to lower CleanPowerSF electricity supply rates by 25% for residential and some commercial customers and by 20% for all others.

"We have a strong financial reserve policy for CleanPowerSF," Hyams added. "We keep a certain amount of cash on hand to help us manage both fluctuations in the PG&E rates and power market prices. This reserve, plus an anticipated reduction in power supply costs, made the case for drawing down the reserve over the next two years. "We're projecting that in 2028, we will need to increase our rates again, but we'll be starting from that lower base that we've just implemented."

Freiberg added, "We knew that any rate decrease would have a requisite rate rebound, so we evaluated various scenarios. Even with the rate rebounds, it won't be until 2031 before our rates are back to where they were before we made the rate reduction."

Without that subsidy from the reserves, Freiberg said residential and large commercial customers would have been those most heavily impacted by the increase in PG&E rates and fees. Now, residential customers will only see a $1 or $2 increase.

Along with financial reserves, SFPUC is leveraging supply budget flexibility to provide the CleanPowerSF rate reductions. "We build in some conservatism, and we call it a contingency in case power supply market prices change relative to what we were forecasting at the time that we put our budget in place. And that contingency serves almost like another buffer against having really volatile rates," Hyams said.

Freiberg summed up the value of this conservative approach. "If I had to generalize why we're able to decrease CleanPowerSF rates, it's really just old-fashioned risk management," he said.

Promoting and Seeing the Value in Demand Response

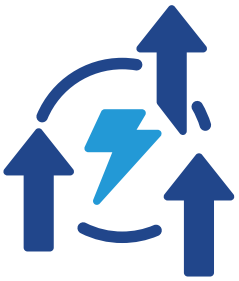
BY PAUL ZUMMO, DIRECTOR, ENERGY EFFICIENCY DEVELOPMENTS AND STATISTICS, AMERICAN PUBLIC POWER ASSOCIATION

Demand response, or DR, programs have long been a key tool in peak load management and can play a vital role in ensuring a resilient grid amid mounting load growth. These programs can also be an effective means to cost savings for utilities and customers alike.

Demand response is when consumers adjust electricity usage in response to signals from their utility. These signals can be delivered to residential, commercial, and industrial customers through price changes, financial incentives, or requests to reduce consumption during peak periods.

For utilities, DR nets savings by reducing costs associated with peak load and can allow them to defer investments in costly new infrastructure. While DR nets long-term benefits, utilities have to make initial investments in technologies such as advanced metering infrastructure and control systems to enable DR programs.

Data show that public power both is and isn't making the most of DR. In 2024, the Energy Information Administration showed that approximately 1.2 million of the nearly 11 million customers signed up for utility DR programs were public power utility customers, or just over 10%, even though public



1.6 gigawatts demand response savings potential for public power

1.2 million public power customers signed up for demand response

power customers comprise 15% of the market. However, of the 409,403 megawatt-hours total energy savings from DR programs across the U.S., 130,028 MWh, or 32%, were from public power utility programs. Still, the potential peak demand savings — meaning the total amount of capacity which could be saved if all customers who signed up for DR programs were able to curtail energy usage when called upon — was over 31 gigawatts, with actual peak demand reduction totaling 12 GW, or 1.6 GW for public power utilities.

Public power DR programs continue to grow not just in size and reach, but also in variety.

Hingham Municipal Lighting Plant in Massachusetts realized $70,000 in net avoided transmission and capacity costs within one year of joining the Massachusetts Municipal Wholesale Electric Company's Connected Homes program. The program allows participating utility customers to enroll smart devices; the utility can then automatically shift those devices' energy consumption away from peak demand periods.

Encouraging customers to participate might involve offering incentives for signing up or actually participating.

In Michigan, residential customer participants in Lansing Board of Water & Light's Peak Power Partner DR program receive a $50 check for enrolling and $25 at the end of the year if they opt into at least 50% of called events.

Austin Energy in Texas has a long-term strategy to achieve 270 MW of DR by 2035.

The public power utility provides both a price signal option and a control option for its commercial customers. Businesses enrolled in its standard DR program earn bill credits based on each kilowatt saved when called to reduce usage during peak periods. Business customers that have implemented automated DR can opt into Fast DR, where they do not have to take any measures to reduce consumption after receiving a notification, as it is done automatically. Fast DR enrollees receive bill credits $10–$15 higher per kW compared to standard DR, and Austin Energy offers additional incentives for participants' first year. Austin Energy's website noted an example of how a customer saved tens of thousands of dollars on energy bills under each program. As of July 2025, Austin Energy had 195 buildings enrolled in its program.

With electrification and data center load growth, utilities are working with tech companies and automakers to design more effective DR programs.

In California, the Sacramento Municipal Utility District's managed charging pilot for residential customers who own or lease qualified electric vehicles aims to reduce peak load by scheduling participants' EV charging to lower demand hours. SMUD worked with vehicle manufacturers to ensure the program aligned with existing vehicle applications and technology for managing charging, and to ensure participants can override the schedule in case of immediate need.

After seeing how it could successfully shift usage at a data center within Omaha Public Power District's service area, Google signed an agreement with Tennessee Valley Authority that shifts non-urgent, energy-intensive machine-learning processes, such as processing YouTube videos, to lower-demand hours.

All these programs require customer awareness and education to help achieve load management and cost savings. HMLP, for example, used MMWEC's marketing toolkit for the Connected Homes program to engage customers and increase participation.

Brianna Bennett, who manages customer programs and rebates at HMLP, explained, “Our approach was simple: Market consistently, listen closely, and fill the gaps. Each time we addressed customer concerns and adapted, we earned more buy-in.”

PUBLIC POWER COMMUNITIES

MILFORD, DELAWARE

POPULATION: **14,079**
ELECTRIC CUSTOMERS: **8,740**
UTILITY FORMED: **1908**
UTILITY EMPLOYEES: **17**

The electric department in Milford, Delaware, was formed in 1908 when the city decided to manage its own electricity rather than rely on private companies. This was both a practical and community-minded choice, as Milford was rapidly developing around the turn of the 20th century due to commerce brought from its shipping port.

Milford has evolved significantly since, with the economic boom that arrived with the opening of its shipyard laying the foundation for a town that has remained a hub of commerce and culture. While the historic shipyard no longer serves as a major transit hub, Milford remains a thriving town that is once again experiencing a wave of development supported by its public power utility.

Lauren Swain, the city of Milford's economic development and community engagement administrator, said commitment to both civic and environmental stewardship has long been integral to the town's culture.

"We're known throughout the state as 'Rivertown, Art Town, Hometown.' The city celebrates the beauty of its natural resources, its people, and its commitment to quality of life," Swain said.

"We're lucky to have our entire team living here as we plan for the future, especially since we love our hometown and everything about Milford."

She said the electric utility's integration with the city has been vital for sustaining a community that continues to grow and thrive into the 21st century.

"The best part is knowing that everything we do directly benefits our customers and our city. Decisions aren't driven by shareholders but instead by what's best for our city. We can direct our resources where they're most needed and focus on providing the best value for our customers," Swain said.

Milford Electric's close relationship with the community has fostered a greater sense of closeness, especially since its staff are a vital part of community life.

"Our employees are part of the community and regularly interact with our customers as part of our normal operations," Swain said. "You'll see us at local events, supporting schools, and volunteering for community projects. When storms hit or outages occur, we're out there working hard to restore power because we know the people we're helping personally."

Milford Electric Department crew members.

The town has experienced significant growth, with its population more than doubling over the past 20 years along with a wave of economic development, including the Milford Corporate Center, a business park slated to complete its first phase at the beginning of the summer. Swain, who was born and raised in Milford, noted how residents are grateful that the town is building infrastructure that will provide quality employment for the next generation.

"We're excited that we're building a corporate center so our kids and their kids can be employed here," Swain said. Some of the current largest employers (and electric customers) in the city are health systems and Perdue Farms.

Like other towns supported by a public power utility, Milford's affordable electric rates and quality of service have proven appealing to companies looking to settle in the area. The electric department's commitment to affordability and reliability has served as a standout example for how public power provides the foundation for a sustained quality of life over generations.

Swain said the department's priorities include maintaining exceptional reliability while continuing to invest in grid modernization.

"We have a major battery energy storage system underway that will help with reducing our system peak load while also allowing us to increase the amount of solar we can interconnect on our system. We expect it to provide other benefits as well, such as improved grid reliability and resilience. We're also focused on energy efficiency programs to help customers manage cost and reduce environmental impact. Ultimately, our goal is to keep Milford's electric system strong, sustainable, and ready for the future," Swain said.

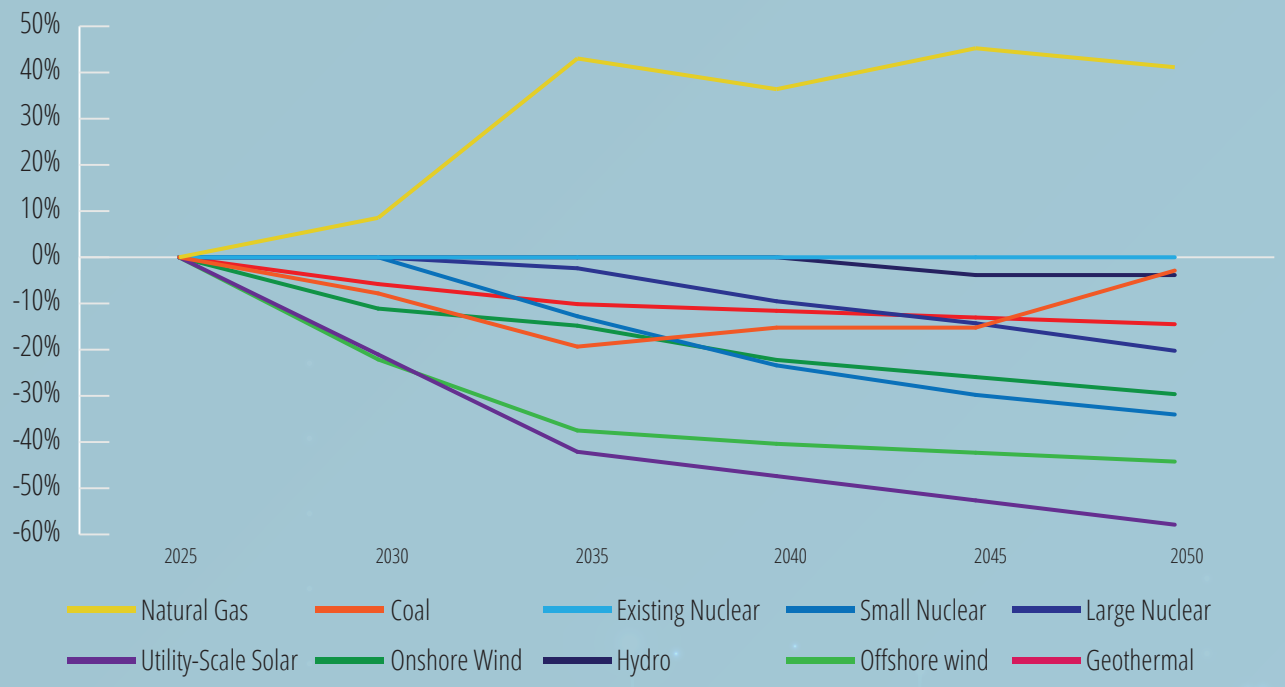
She emphasized that the success of Milford's electric department comes from the commitment of its staff and their closeness to the community.

"Our utility employees go above and beyond every single day. We're lucky to have our entire team living here as we plan for the future, especially since we love our hometown and everything about Milford," Swain said.

HOW WILL ELECTRICITY COSTS CHANGE BY GENERATION SOURCE?

Total U.S. electricity generation is expected to increase 50% from 2024 to 2050. As new generation sources are added, the cost for securing supply from different generation sources is expected to change.

Projected change in fuel price by type, 2025-2050



The average cost of utility-scale solar is expected to drop nearly 60%.

The average price of natural gas is projected to increase by 41%.

The price of coal is expected to drop almost 20% by 2035, and then increase again through 2050.

The drops in utility-scale solar and onshore wind project these sources to be among the most cost-effective fuel sources by 2050. ($16/MWh for solar and $19/MWh for wind)

The capital cost for utility-scale battery storage is projected to decrease 51% from $320 kWh in 2025 to $157 kWh in 2050.

Sources:
Electricity Annual Technology Baseline, National Laboratory of the Rockies. https://atb.nrel.gov/electricity/2024b/data
Annual Energy Outlook 2025, Energy Information Administration. https://www.eia.gov/outlooks/aeo/

Note: Coal, natural gas, and existing nuclear projected costs are based on the cost of the fuel itself. Other fuel sources are measured in levelized cost of energy (LCOE), which includes capital expenditures and operating costs. Projections are based off the dollars per megawatt-hour in 2022 dollars.

CONGRATULATIONS

to the 2026 Reliable Public Power Provider (RP3) program designees. We salute your commitment to operating at the highest levels of reliability, safety, workforce development, and system improvement as you build and support strong communities.

DIAMOND

Alameda Municipal Power, CA
Bay City Electric Light and Power, MI
Beaches Energy Services, FL
Belmont Light, MA
Brownsville Public Utilities Board, TX
Bryan Municipal Utilities, OH
Bryan Texas Utilities, TX
BVU Authority, VA
Carthage Water & Electric Plant, MO
CDE Lightband, TN
Cedar Falls Utilities, IA
City of Cuyahoga Falls Electric Department, OH
City of Dover Electric Department, DE
City of Fort Collins Light & Power, CO
City of Grand Island Utilities Department, NE
City of Hamilton Electric Department , OH
City Utilities of Springfield, MO
Clark Public Utilities, WA
Conway Corporation, AR
Detroit Lakes Public Utilities, MN
Easton Utilities Commission, MD
Elk River Municipal Utilities, MN
Groton Utilities, CT
Hillsdale Board of Public Utilities, MI
Homestead Energy Services, FL
Jackson Energy Authority, TN
Kaukauna Utilities, WI
Keys Energy Services, FL
Lafayette Utilities System, LA
Lansing Board of Water & Light, MI
Marietta Power, GA
Marshall Municipal Utilities, MN
Mason PUD 3, WA
Menasha Utilities, WI
Montpelier Municipal Electric, OH
Morristown Utilities, TN
Muscatine Power & Water, IA
Naperville Electric Utility, IL
Nashville Electric Service, TN
Nebraska Public Power District, NE
Nixa Municipal Utilities, MO
Ocala Electric Utility, FL
Paducah Power System, KY
Peru Utilities, IN
PUD #1 of Clallam County, WA
Santee Cooper, SC
Springfield Utility Board, OR
Statesville Public Power, NC
Tell City Electric Department, IN
Town of Tarboro, NC
Village of Versailles, OH
Westfield Gas + Electric, MA
Willmar Municipal Utilities, MN
Wilson Energy, NC

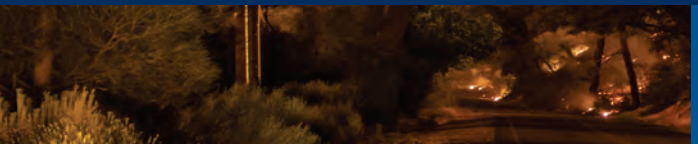
PLATINUM

Algona Municipal Utilities, IA
ALP Utilities, MN
Bolivar Energy Authority, TN
Borough of Chambersburg, PA
Bowling Green Municipal Utilities, KY
Brainerd Public Utilities, MN
City of Anaheim Public Utilities Department, CA
City of Banning Electric Utility, CA
City of Fort Morgan Light and Power, CO
City of Fulton, MO
City of Garden City Electric Department, KS
City of Marshall Electric, MI
City of Mesa Energy Resources, AZ
City of Milford, DE
City of Monroe, NC
City of Morganton, NC
City of St. George, UT
City of Westerville, OH
Cleveland Utilities, TN
CPS Energy, TX
Danvers Electric Division, MA
Edmond Electric, OK
Farmington Electric Utility System, NM
Henderson Municipal Power and Light, KY
Holden Municipal Light Department, MA
Littleton Electric Light and Water Departments, MA
Marshall Municipal Utilities, MO
McMinnville Electric System, TN
Middleton Electric Light Department, MA
Moreno Valley Electric Utility, CA
Napoleon Power & Light, OH
New River Light & Power Company, NC
Orlando Utilities Commission, FL
Riviera Utilities, AL
Rochester Public Utilities, MN
Rockwood Electric Utility, TN
Rocky Mount Energy Resources, NC
Seattle City Light, WA
Tacoma Power, WA
Taunton Municipal Lighting Plant, MA
Turlock Irrigation District, CA
Village of Minster, OH
West Memphis Utility Commission, AR
Winchester Utility System, TN

GOLD

Brigham City Public Power, UT
City of Mount Dora Electric Utility, FL
City of Newark, DE
City of Newton, NC
City of Santa Clara, UT
Evansville Water and Light, WI
Harrisonburg Electric Commission, VA
Ipswich Electric Light Department, MA
Lakeland Electric, FL
Lassen Municipal Utility District, CA
Lawrenceburg Municipal Utilities, IN
New Braunfels Utilities, TX
Rochelle Municipal Utilities, IL
Salt River Project, AZ
Scottsboro Electric Power Board, AL
SMTX Utilities, TX
Stowe Electric Department, VT
Town of Cornelius, NC
Town of Huntersville, NC
Town of Pineville, NC

RP3 RELIABLE PUBLIC POWER PROVIDER
American Public Power Association



RS RESILIENT STRUCTURES
FOR A RELIABLE GRID

WHEN FAILURE IS NOT AN OPTION, UTILITIES RELY ON RS ENGINEERED COMPOSITE POLES

The reliability of the world's electric power grid is tested time and again by extreme weather, challenging remote locations, or the use of inferior materials for supporting critical structures and circuits. These events can disrupt communities, compromise infrastructure, and leavemillions without power. Each disruption underscores how essential it is to maintain strong, resilient connections.

RS | Resilient Structures is a global leader in advanced composite utility poles, trusted by 500+ utilities in 30+ countries to deliver reliable, resilient, cost-effective grid infrastructure.

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