

Smart Electric Power Alliance

NRECA
America's Electric Cooperatives

SEPA and NRECA Resilience Planning Playbook for Electric Cooperative Utilities

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About SEPA

The Smart Electric Power Alliance (SEPA) helps all electric power stakeholders accelerate the transformation to a carbon free electricity system. SEPA concentrates our focus on the following areas to maximize impact: Transportation, Storage, Resilience, Emerging Technology, Policy, and Energy Equity. SEPA delivers value to our members through research, education, events, working groups, peer engagements, and member projects. We facilitate collaboration, develop innovative strategies and guidance for regulatory and business innovation, and provide actionable solutions for our members and partner organizations. For more information, visit www.sepapower.org.

About NRECA

The National Rural Electric Cooperative Association (NRECA) represents more than 900 consumer-owned, not-for-profit electric cooperatives, public power districts, and public utility districts in the United States. NRECA is the national service organization that represents America's electric cooperatives. Below are some of the services NRECA provides to and on behalf of its members:

- Sponsors and administers employee benefit plans for participating cooperatives
- Spearheads communications, advocacy and public relations initiatives
- Carries out federal government relations activities
- Conducts leadership and staff training
- Coordinates national and regional conferences and seminars
- Researches, educates and communicates with NRECA voting members regarding legal, tax, environmental, engineering and other issues
- Performs economic and technical research
- Champions the cooperative business model

For more information, visit www.electric.coop.

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Importance of Resilience Planning

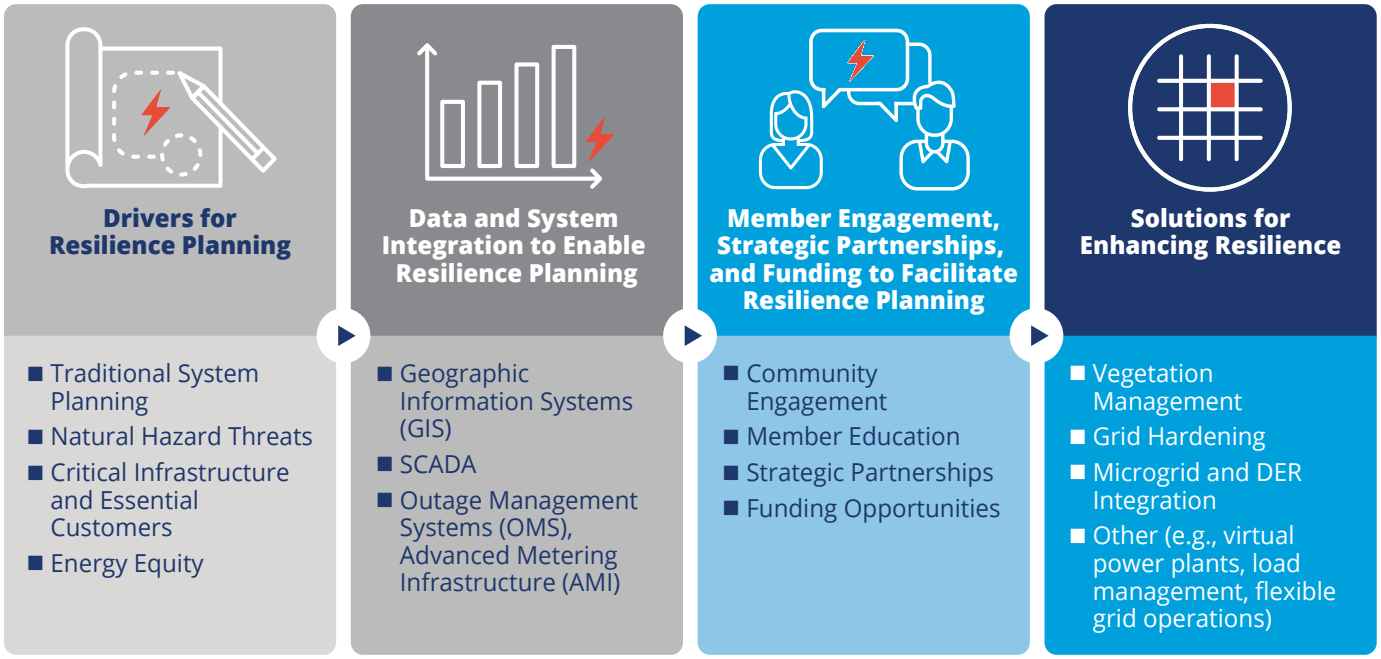
Electric cooperatives (co-ops) across the U.S. are navigating an evolving energy landscape shaped by increased electrification, new technology demands, policy-driven decarbonization goals, and the growing impact of extreme weather events. In particular, the destructive and damaging 2024 hurricanes Helene and Milton in Florida and the Carolinas have illustrated that it is essential for co-ops to prioritize resilience during grid planning to withstand outages more effectively, recover more quickly from disasters, and adapt to changing energy demands.

Co-ops can lead by deploying consumer-centric resilience solutions that align with their mission as member-owned, not-for-profit utilities. Co-ops are governed by member-elected boards and focus on serving rural and dispersed populations, where maintaining reliable service is essential but can be resource-intensive. As they step up to meet the challenges of increasingly extreme weather and growing electric demand, co-ops are finding that resilience planning requires balancing traditional planning objectives, such as affordability and reliability, with their policy goals tied to sustainability and energy access for all.

About the SEPA and NRECA Resilience Planning Playbook

Drawing from conversations with the Smart Electric Power Alliance (SEPA) and National Rural Electric Cooperative Association (NRECA), this resource affords co-ops the opportunity to learn from one another through case studies, best practices, and real-world insights from those already navigating new approaches to resilience planning. By building on the successes and lessons of their peers, co-ops can strengthen their resilience strategies, protect their communities from costly disruptions, and ensure that they're prepared for the future's evolving energy demands and environmental conditions. This playbook builds on traditional system planning elements and translates high-level concepts in resilience planning from research into solutions (see Figure 1).

Figure 1. Key Considerations for Resilience Planning for Co-ops



Source: SEPA (2024).

Background

SEPA has over 1000 members, over 140 of which are electric co-ops. To comprehensively understand the approach co-ops are taking to resilience planning, SEPA partnered with NRECA, the national trade association for electric coops. Through this partnership, SEPA and NRECA developed this educational resource to highlight best practices, lessons learned, and case studies on how co-ops are prioritizing resilience investments in grid planning to benefit their members.

Co-ops were established in 1937 with the Rural Electrification Administration to bring electricity to rural areas that for-profit utilities would not serve. According to NRECA, these co-ops provide electricity to 42 million people, covering 56% of the nation's landmass. As a result, equity is at the core of a co-ops operations by ensuring that rural and underserved populations have electricity and, in some cases, providing broadband access as well. This focus aligns with state and federal initiatives that prioritize investing in underserved communities and resilience.

In August 2024, SEPA hosted a workshop for co-ops with NRECA centered around resilience planning and resilience investments that was open to all co-ops. Thirty-four co-op employees from 21 different utilities were in attendance to provide input on their resilience planning strategies. For a full list of participating co-ops, see Appendix B.

During the workshop, SEPA and NRECA gathered insights from attendees across several key areas of resilience planning. This included their approaches to engaging with their members and communities on resilience planning, how they measure reliability and use resilience metrics, and the data they collect to support these efforts. They also discussed the factors they consider when identifying resilience needs, the types of investments made to strengthen reliability, their use of distributed energy resources (DERs), and the perceived risks and challenges associated with deploying new resilience solutions.

From the dense forest mountains of Virginia to the wildfire-prone regions of Colorado, cooperatives exist in different environments and are pursuing innovative solutions, leveraging emerging technologies, and actively engaging their communities in resilience planning. This playbook builds on SEPA's prior resilience planning work. It synthesizes a range of co-op case studies, offering insights into the unique challenges and opportunities faced by a sample of co-ops as they better integrate resilience into their system planning efforts.

Utility Case Studies

A comprehensive collection of the referenced case studies can be found in Appendix A: Utility Case Studies.

For more background on SEPA's Resilience Planning efforts, see the Resilience Playbook for States and Utilities, which documents methodologies and frameworks for grid resilience planning based on experience working with state energy office and utility members across the country.

To provide a clear structure for this playbook, the following sections are organized into key themes highlighting various aspects of resilience planning for electric cooperatives. Each section includes real-world case studies and practical insights to guide co-ops' efforts. These themes include:

1. **Drivers for Resilience Planning:** Examining how co-ops are evolving their traditional planning processes to address modern challenges, including natural hazards, energy access, and critical infrastructure needs.
2. **Data and System Integration:** Exploring how co-ops leverage advanced data collection and management systems to enable proactive resilience planning and real-time grid operations.
3. **Member Engagement, Strategic Partnerships, and Funding:** Highlighting the role of member engagement, innovative partnerships, and federal and state funding opportunities in de-risking resilience investments.
4. **Solutions for Enhancing Resilience:** Showcasing both traditional and emerging resilience strategies and their applications.

Each of these sections provides actionable guidance and examples from peer utilities to help co-ops navigate the evolving energy landscape and prioritize investments that support their members, communities, and broader organizational goals.

Drivers for Resilience Planning

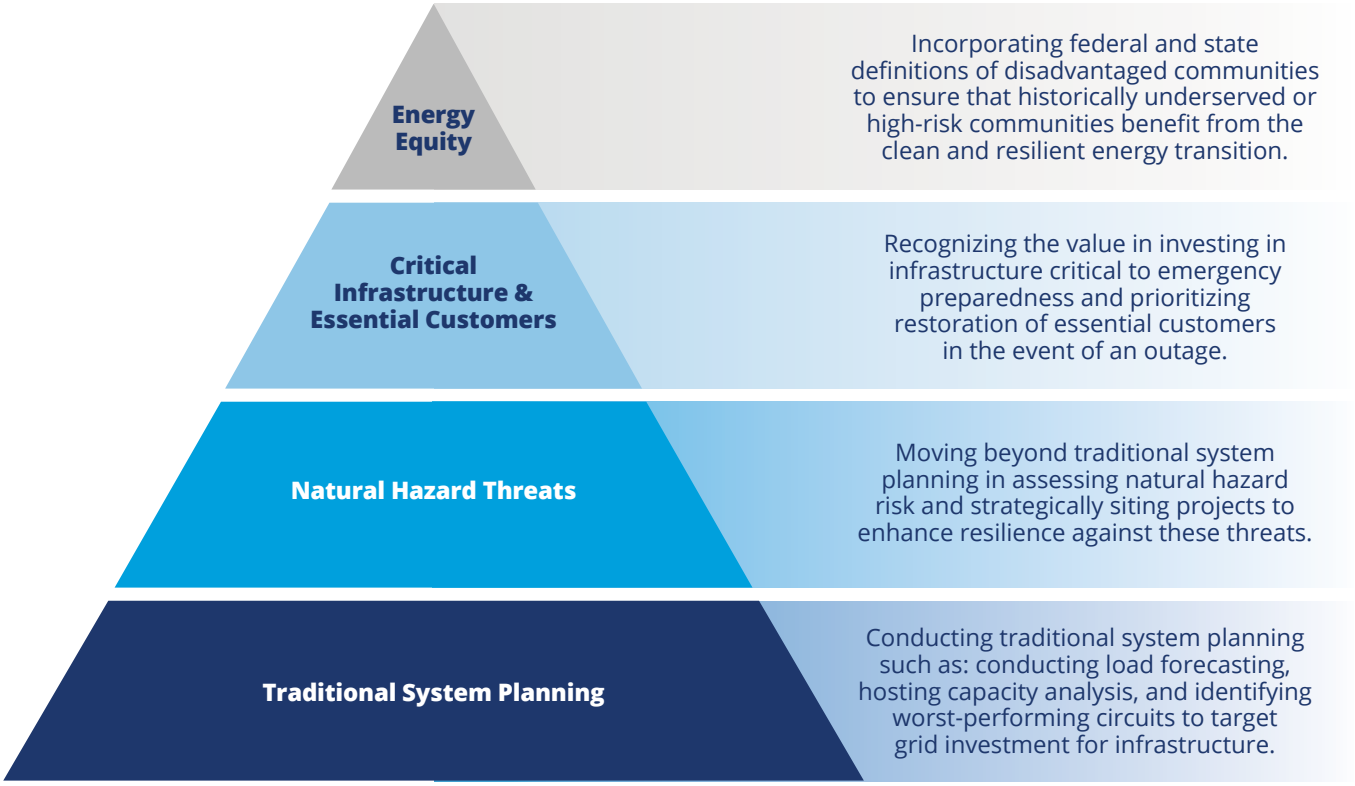
Building on Traditional Utility Planning to Support Resilience

Grid planning for co-ops is tailored to their unique challenges, resources, and their commitment to provide affordable, reliable, and safe power for their members. Increasingly, co-ops in certain parts of the country are expanding their approach to address growing customer demand and policy changes, focusing on equitable, sustainable, and resilient electrical service.

Figure 2 highlights the evolution in resilience planning beyond traditional system planning that incorporates energy equity considerations, essential customer prioritization, and natural hazard threats to optimize investments.

- **Traditional System Planning.** Key activities are identifying worst-performing circuits, utilizing reliability statistics to target grid investment for infrastructure that is aging and vulnerable to outages, conducting load forecasting, and hosting capacity analysis to identify necessary capacity upgrades to support load growth and DER deployment.[1]

Figure 2. SEPA's Resilience Planning Pyramid



Source: SEPA (2024).

1 There are several metrics commonly used to assess distribution system reliability. Some of the most common metrics include; System Average Interruption Duration Index (SAIDI) which measures the average outage duration for each customer, System Average Interruption Frequency Index (SAIFI) which measures the average number of interruptions that a customer would experience and Customer Average Interruption Duration Index (CAIDI) which measures the average outage duration that any given customer would experience.

- **Natural Hazard Threats.** Co-ops are emphasizing the importance of assessing natural hazard risk to identify projects that enhance resilience against these threats.
- **Critical Infrastructure and Essential Customers.** Co-ops also recognize the value of investing in infrastructure critical to emergency preparedness and prioritizing restoration of essential customers during outages. State and county inventories and FEMA-identified community lifelines provide valuable resources to co-ops for identifying key facilities and guiding resilience investments.
- **Energy Equity.** Due to community needs and policy drivers, co-ops are also beginning to incorporate federal and state definitions of disadvantaged communities to identify historically underserved or high-risk communities that could benefit from the clean and resilient energy transition and related investments.

Table 1. Case Study Examples of Drivers for Resilience Planning

Utility Case Study	Examples
Southern Maryland Electric Cooperative (SMECO) (Maryland)	SMECO is now required to submit updated Distribution System Planning (DSP) reports to the Maryland Public Service Commission that go beyond traditional methods to address modern demands with a focus on resilience and sustainability. In preparation for these new processes, SMECO must develop strategies to reduce emissions, prioritize infrastructure upgrades in vulnerable communities, enhance energy efficiency, manage load growth, integrate energy storage, handle load variability, enable bidirectional power flows, leverage demand response, and increase the adoption of DERs and electric vehicles (EVs).
La Plata Electric Association (LPEA) (Colorado)	LPEA faces aging infrastructure and increasing electricity demand due to electrification and other commercial growth, which has highlighted the importance of updating their distribution system planning processes and techniques. LPEA is preparing for independence from Tri-State, its current wholesale power provider, in 2026. They aim to act as a Distribution System Operator (DSO), managing local DERs to improve resilience. This shift enables LPEA to optimize grid stability by prioritizing battery storage projects and integrating solar energy, allowing them to balance resilience with sustainability goals.
South Central Power (SCP) (Ohio)	SCP developed a "Future Strategic Plan" that prioritizes capital projects based on criteria such as reliability, load growth, and outage frequency, integrating resilience metrics to guide investments.
Vermont Electric Power Company (VELCO) (Vermont)[2]	VELCO is a transmission-only utility and historically has not played much of a planning role in the distribution system. Given the growth of DERs in Vermont, VELCO has established a transmission-distribution (T&D) interface that allows for coordinated DER integration and flexible load management and is intended to facilitate the growth of DERs in Vermont. They are working closely with Vermont's distribution utilities to support the integration of over 50 MW of virtual power plant (VPP) capacity to enhance grid flexibility across the state.
Holy Cross Energy (Colorado)	Holy Cross Energy is a mid-sized cooperative serving wildfire-prone areas in the Rocky Mountains of Colorado. Due to increased wildfire risk, Holy Cross Energy has developed a comprehensive wildfire resilience strategy that focuses on bulk supply resilience, mobile generation fleets, backup power for refuge centers, and assessing energy needs for critical infrastructure to ensure the continuity of critical services.

Source: SEPA (2024).

2 While VELCO is not a co-op they were invited to participate in workshops given their similar ownership structure to co-ops—VELCO is owned by the 17 distribution co-ops that they serve.

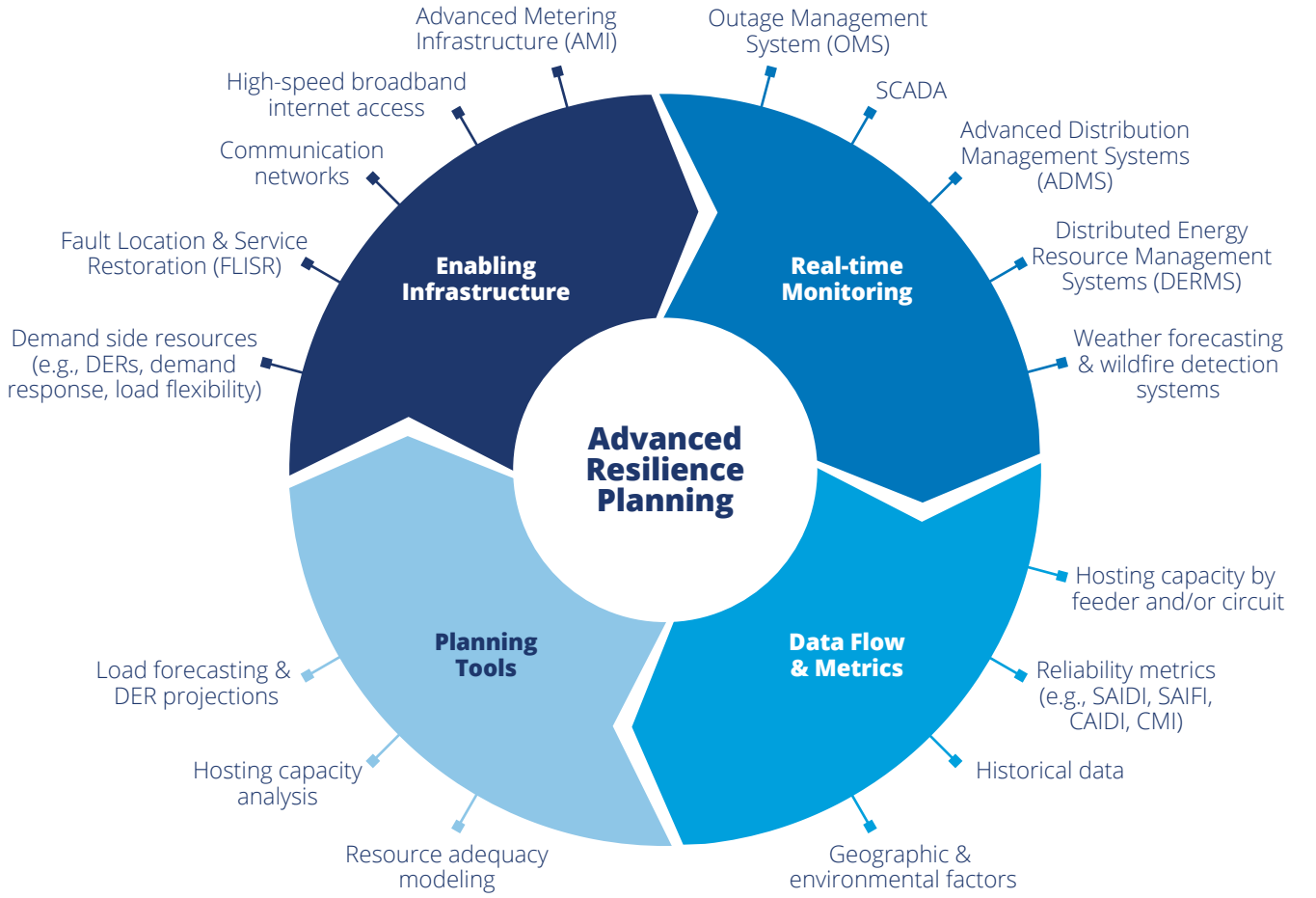
Data and System Integration to Enable Advanced Resilience Planning

A leading principle of grid resilience is the capability to prepare for system failures and to plan accordingly. Advancements in data integration and management systems enable real-time monitoring, automated response capabilities, and enhanced visibility for utilities to prepare and plan their systems to address emerging resilience threats. Co-ops have had success in utilizing historical reliability data, infrastructure conditions, geographic and environmental factors, and customer impact to inform grid and customer investments. There are several examples across the country where co-ops are effectively collecting and analyzing data to support resilience efforts, such as outage frequency, consumer impact, and infrastructure health.

Cybersecurity assessments are a critical component of data and system integration. As more DERs are added to the grid, the utilities are responsible for protecting their assets and the flow of power and data to their members. NRECA has developed several cybersecurity resources to help its members prepare for existing and potential threats to their grid.

Figure 3 illustrates the relationship between collecting and integrating real-time operations and communicating with customer- and utility-sited DERs, and how this greater visibility into utility operations can enable co-ops to conduct more advanced resilience planning.

Figure 3. Data and System Integration to Enable Advanced Resilience Planning



Source: SEPA (2024).

Table 2. Case Study Examples of Integrating Data and Systems to Enable Advanced Resilience Planning

Utility Case Study	Examples
Central Virginia Electric Cooperative (CVEC) (Virginia)	CVEC targets its worst-performing circuits[3] based on SAIDI, CAIDI, and SAIFI, focusing annually on the bottom 10% of its circuits based on reliability statistics. This approach allowed CVEC to prioritize critical circuits like Circuit 501, which recently saw reduced SAIDI values after targeted resilience upgrades. In addition, CVEC deployed battery storage projects at its Piney River and Colleen substations to address seasonal peak demands and reliability concerns.
Utilities District of Western Indiana (UDWI) (Indiana)	UDWI leverages advanced systems, such as Geographic Information Systems (GIS), SCADA, and Outage Management Systems (OMS), to preemptively detect faults. By incorporating these insights into grid management, UDWI can optimize resource allocation and improve reliability across its rural service area.
Connexus Energy (Minnesota)	Connexus emphasizes the importance of tracking the effectiveness of resilience investments using reliability and resilience metrics to effectively monitor and adapt to evolving grid needs. Using an OMS alongside AMI data, Connexus continuously tracks outage causes and restoration times.
South Central Power (SCP) (Ohio)	SCP is taking a phased approach to grid improvements, focusing on reducing restoration times and enhancing service reliability. They were recently awarded a broadband grant to expand high-speed internet to unserved areas. This investment is integrated with advanced metering infrastructure (AMI) and fault location and service restoration (FLISR) automation to enable real-time data management and monitoring. By investing in high-speed internet and AMI, SCP gains greater visibility into real-time electricity usage and DERs across its system which creates a foundation for the utility to pinpoint problem areas and optimize resilience investments.
Vermont Electric Power Company (VELCO) (Vermont)	VELCO adheres to NERC standards and conducts contingency analysis to prepare for potential system failures. They use reliability metrics, such as SAIDI and SAIFI, to continuously monitor performance and prioritize upgrades, meeting the high standards required of a transmission-only operator.
Kenergy (Kentucky)	Kenergy envisions achieving comprehensive resilience through territory-wide broadband access. Kenergy is rolling out the deployment of fiber-optic connectivity to its entire membership. Their desired impact is to establish reliable communication infrastructure that can enable smart grid applications, demand response programs, and other DER integration. One example of broadband-enabled technology is to enable the deployment of virtual power plants to allow small customer contributions to improve the grid's flexibility and resilience.

Source: SEPA (2024).

Member Engagement, Strategic Partnerships, and Funding to Facilitate Resilience Planning

Resilience isn't only about grid infrastructure; it is also about the communities co-ops serve and the strategic investments and partnerships they utilize to maximize the potential for resilience investments to benefit members and communities affordably and equitably. Co-ops can successfully serve their communities by directly engaging with member-consumers to establish beneficial programs and partnering with research institutions and technology companies to pursue state and federal funding. These types of successful engagements and partnerships (see Figure 4) can de-risk co-op investments in emerging clean energy technologies and programs.

3 Every utility defines their worst-performing circuits differently, however, they typically refer to the electrical circuits within a utility's grid that consistently experiences the most frequent and longest power outages, resulting in the lowest level of reliability compared to other circuits in the same system.

Figure 4. Member Engagement, Strategic Partnerships, and Funding to Facilitate Advanced Resilience Planning



Source: SEPA (2024).

Federal and State Funding Opportunities

At the federal level, several funding programs can directly support utility resilience investments, especially DER deployments for resilience. Relevant federal programs include:

- **FEMA's Building Resilient Infrastructure and Communities (BRIC)** is a reoccurring program that supports states, local governments, tribes, and territories in reducing natural hazard risk to their communities. BRIC is focused on proactive investment in community resilience and favors projects that take innovative partnership approaches. BRIC investments often support infrastructure projects benefitting disadvantaged communities and increasing natural hazard resilience and adaptation. For more information about how co-ops can engage with FEMA's BRIC program, see additional resources from NRECA on "Understanding FEMA's BRIC Program."
- **DOE Office of Clean Energy Demonstrations (OCED) Energy Improvements in Rural and Remote Areas (ERA)** includes $1B in funding to improve the resilience, reliability, and affordability of energy systems in rural and remote communities across the country (i.e., those with 10,000 or fewer people). This funding primarily supports community-driven clean energy projects to deliver measurable benefits to customers. In February 2024, OCED announced over $366 million for 17 projects across 20 states and 30 Tribal Nations and Communities to lower energy costs and enhance energy security. In October 2024, OCED issued a Notice of Funding Opportunity of $400 million with a deadline for concept papers in February 2025 and full applications in August 2025.
- **DOE Grid Deployments Office (GDO) Grid Resilience and Innovation Partnerships (GRIP)** includes $10.5 billion to improve power system resilience in the face of extreme weather. GRIP funding supports projects that will help to ensure the reliability of the power grid and ensure access to affordable, reliable, and clean electricity. The first round of GRIP funding was announced in October 2023 which provided $3.5 billion for 58 projects across 44 states. Hoosier Energy Rural Electric Cooperative received over $116 million to build a new transmission feed. The second round of funding was announced in October 2024 which provided an additional $4.2 billion for 46 projects, including Randolph Electric Membership Corporation's $11.4 million award to bolster grid resilience in North Carolina. According to Baker Tilly, the third round of funding isn't anticipated until the spring of 2025.
- **USDA's Empowering Rural America Program (New ERA)** provides funding to member-owned rural electric cooperatives. The program includes $9.7 billion in loans, grants, and financing for co-ops to make energy efficiency improvements to eligible generation and transmission systems, to purchase, build, or deploy renewable energy, zero-emission systems, carbon capture storage systems, or to purchase renewable energy. In October 2024, the program invested $2.5 billion in financing for Tri-State Generation and Transmission Association to lower electricity costs and reduce pollution across multiple states and the program is expected to continue into 2025 to support co-ops.

Alongside the many federal funding opportunities currently available to support resilience investments, states, and local governments often leverage funding from the State Energy Program or other sources to provide region-specific support for resilience solutions.

Co-ops can also partner with member finance organization programs like the National Rural Utilities Cooperative Finance Corp (CFC) and CoBank to access funding.

With state and federal funding opportunities in mind, NRECA has created several consortia that have helped organize their members to bid on funding that would otherwise likely be inaccessible to them. NRECA's Microgrid Consortium organized a winning bid of seven electric co-ops to apply for the DOE OCED ERA funding for more than $45 million. This program aims to improve reliability and resilience in remote areas, and NRECA's funding will go towards developing microgrids to support communities' resilience. Additionally, NRECA's grid integration consortium was awarded over $97 million under DOE's GRIP program for 11 electric co-ops to develop and upgrade transmission lines to support resilience and transfer capacity for additional renewable generation interconnection.

Table 3. Case Study Examples on Customer Engagement, Strategic Partnerships, and Funding to Facilitate Resilience Planning

Utility Case Study	Examples
LPEA (Colorado)	LPEA partnered with the National Renewable Energy Laboratory (NREL) and the Southern Ute Tribe to obtain federal funding for battery storage and wildfire mitigation investments on Tribal land. This partnership also led to the installation of smart reclosers and vacuum reclosers on outage-prone Tribal lands which has enabled LPEA to facilitate DER and microgrid adoption.
UDWI (Indiana)	UDWI is deploying member engagement platforms through its partnership with Meridian Cooperative to better inform its members about outages and reliability initiatives.
VELCO (Vermont)	VELCO worked closely with PNNL and ORNL to develop Common Information Model (CIM) simulations that improve transmission-distribution coordination.
Cobb EMC (Georgia)	Cobb EMC is engaging its members with time-of-use rates and education about demand management.
SCP (Ohio)	In response to the increase in peak demand, SCP established a "Rate Committee" that is responsible for establishing and approving new rate classes for new loads, such as data centers. The correction makes commercial requests for loads balance out with funding for resiliency and aligns SCP pricing structures and operational needs.
Holston Electric Cooperative (HEC) (Tennessee)	HEC and BoxPower collaborated to utilize BoxPower's Microgrid Integration Survey (MGIS) to scan their worst-performing circuits to identify optimal microgrid integration opportunities that would improve end-of-line reliability along with grid services for their broader membership.

Source: SEPA (2024).

Solutions for Enhancing Resilience

Electric cooperatives looking to increase the resilience and reliability of their systems have many options to explore, depending on the resilience challenges they have identified, their budgets, and other goals. Traditional resilience solutions that utilities employ include vegetation management, grid hardening, and grid modernization.

Emerging resilience solutions include DER and microgrid integration for grid and member benefit. Each resilience strategy comes with its own benefits and challenges and the decision to deploy a particular strategy often needs to be made on a case-by-case basis.

Vegetation Management

Effective vegetation management is critical for ensuring reliability and mitigating natural threats, such as tree-related service disruptions. Many co-ops deploy advanced technologies, such as Light Detection and Ranging (LiDar) mapping, predictive analytics, and targeted maintenance strategies to identify and address vegetation risks.

Table 4. Case Study Examples for Vegetation Management

Utility Case Study	Examples
CVEC (Virginia)	CVEC uses a proactive, data-driven approach to vegetation management, concentrating efforts on high-risk circuits in its mountainous, forested service area. In 2023, CVEC implemented a satellite-based vegetation management program to identify which circuits are most at risk of tree-related outages. After a successful pilot, CVEC will deploy this technology enterprise-wide, enabling it to proactively address vegetation issues before they cause outages and will shorten restoration times.
Kenergy (Kentucky)	Kenergy utilizes industry-leading technologies, such as LiDAR and AI-based analytics combined with drone inspections, to cultivate best-in-class vegetation management. This process allows Kenergy to only work high-risk sections rather than broader, more costly rotations, keeping maintenance expenses low and reducing outage risks. Treating specific sections within its service area, Kenergy is improving operational efficiency with resilience while preserving resources for other essential projects.
LPEA (Colorado)	LPEA applies targeted vegetation management as part of a greater wildfire resiliency strategy. By engaging the services of valued partners, LPEA takes advantage of satellite imagery to monitor vegetation in very high fire-prone areas, particularly where critical infrastructure could be at risk. This proactive management allows the cooperative to reduce outage risks and help mitigate the threat of wildfires, a very serious concern within its mountainous service area.

Source: SEPA (2024).

Grid Hardening

Grid hardening includes solutions that aim to increase the ability of grid infrastructure to withstand and recover from natural hazards and operate efficiently. Techniques include pole assessment and replacement, undergrounding, and vegetation management. Investments in grid hardening and modernization can reduce replacement costs down the road by ensuring that natural hazard impacts to grid infrastructure are more limited in scope and/or scale. Several co-ops have infrastructure hardening as a key strategy to minimize outage risks from severe weather.

Table 5. Case Study Examples for Grid Hardening	
Utility Case Study	**Examples**
Bon Homme-Yankton Electric Association (BHYEA) (South Dakota)	BHYEA prioritizes resilience by undergrounding approximately 30 miles of its distribution lines each year, aiming to reduce outage risks from storms and natural disturbances. Operating with financial constraints, BHYEA focuses these undergrounding efforts on the most outage-prone, rural sections of its service area to maximize impact per dollar. This gradual but strategic investment is BHYEA's primary approach to fortifying its infrastructure against severe weather events.
Connexus Energy (Minnesota)	Connexus has committed to a 10-year infrastructure plan to improve resilience by undergrounding power lines in high-risk areas vulnerable to frequent weather-related outages. Each year, Connexus transitions approximately 400 lots from overhead to underground service, focusing on the sections of its grid with the highest outage rates. This systematic approach aims to reduce weather-related disruptions and ensure long-term service reliability across its Minnesota service area.

Source: SEPA (2024).

Non-Traditional Resilience Solutions

Traditional system planning often does not account for newer technologies, like DERs. Some electric cooperative utilities are using DERs in the transition towards a resilient grid, despite the fact that traditional planning might not consider them as viable solutions. Integrating non-traditional DER solutions behind-the-meter (BTM) or in-front-of-the-meter (FTM) like solar PV, distributed generation, battery energy storage, and microgrid technologies can provide advanced load control and backup power during grid outages for a single customer or entire community depending on the scale of the solution. In some cases, strategically integrated DERs also can help utilities defer or avoid infrastructure upgrades, especially in rural and remote communities experiencing load growth.

Deep Dive into DERs

Deploying FTM grid-scale and BTM customer-sited DERs can maintain the continuity of critical infrastructure and essential services during grid outages. Communities that are able to maintain their emergency services, life safety, public health, communications, and other critical infrastructure during outages and are often able to avoid the worst impacts of outages. DERs can also provide economic benefits through energy cost savings, peak demand reduction, energy arbitrage, or providing grid services.

Given ideal conditions, DERs can be a cost-effective solution that can reduce customer costs and defer and/or replace traditional infrastructure investments. Based on various conversations with co-ops, ideal conditions include areas with frequent outages, remote and end-of-line areas with recurring hazards and isolated load pockets, socially vulnerable communities, and areas that can host distributed generation and/or would benefit from energy storage.

While the value of deploying DERs as a grid asset for resilience can be significant, there are many perceived challenges and risks associated with selecting them over more traditional grid hardening methods. DERs as a resilience investment are a relatively new concept, and limited case studies demonstrate quantitative resilience benefits under real world operating conditions. Identifying and sharing successful case studies is critical to de-risking projects.

These new solutions have prompted co-ops to begin evaluating different financing and ownership models to reduce capital burdens associated with resilience investments and increase project feasibility. From a financing perspective, co-ops have several options available to them. For some larger coops, an up-front capital investment may be possible, however, many co-ops may prefer to use loans, which require less up-front investment.

A newer financing model, resilience as a service (RaaS) has evolved from the traditional energy as a service (EaaS) model and is being explored by some co-ops looking to enable DER deployment for key account customers while mitigating operational risks. In a RaaS model, the utility can make an upfront investment (typically along with a third-party provider) to jointly own, operate, and maintain the DER assets. In this model, the utility can operate the DER for grid benefit during normal operation and on behalf of the customer during emergency operations, where the utility would provide emergency backup to the customer in return for a monthly or annual premium charge. This

arrangement can potentially de-risk resilience projects by sharing costs among beneficiaries.

Alongside financing, determining asset ownership is another key consideration that may impact the value proposition for a co-op. While a third party or customer may prefer to be the sole owner of a DER project, a co-op may choose to share ownership of assets. For example, a customer-sited solar PV array could be owned by a customer to help reduce energy costs, while a co-located BESS might be owned by the co-op to help reduce system peak demand or provide other grid services. Additional ownership models are highlighted in Figure 5.

Figure 5. DER Ownership Models

Utility Ownership	Developer Ownership	Customer Ownership	Mixed Ownership
Utility owns the assets, taking on greater financing and O&M roles in exchange for increased risk.	Developer owns the assets, removing project risks from utility or electric customer partners who may share in the benefits through service or land lease payments.	Electric customers, particularly large commercial and industrial ones, own the DER assets, often with initial planning and development by a developer but without long-term involvement.	Multi-asset DER projects owned by multiple parties (including utilities, developers, and customers) sharing costs, benefits, and risks.
PRO ■ Reduces operational and interconnection challenges. ■ Ensures long-term utility involvement and control.	**PRO** ■ Reduces risk for utilities and customers while providing flexibility for utilities and/or customers to benefit through joint operating agreements.	**PRO** ■ Increases the benefits for end-use customers. The utility remains involved in interconnection and may purchase excess generation.	**PRO** ■ Allows sharing of costs, risks, and benefits. Flexibility in asset ownership and operation.
CON ■ Potential resource and workforce constraints for smaller utilities. ■ Complexities of coordination between distribution-only and G&T utilities with end-use customers.	**CON** ■ Complexities of financing structures between developers, utilities, and end-use customers.	**CON** ■ Requires customer investment, commitment, and technical expertise. ■ Limited utility role in interconnection and purchasing excess generation.	**CON** ■ Complexity in coordination and management. ■ Requires clear agreements and roles.

Source: SEPA (2024).

Table 6. Case Study Examples for Microgrids and DERs	
Utility Case Study	**Examples**
Cobb EMC (Georgia)	Cobb EMC installed a microgrid at its headquarters with a 1.5 MW solar PV canopy system for charging electric vehicles (EVs), a 1 MW/4 MWh battery storage system, and a natural gas generator for managing peak demand. Cobb EMC is also exploring two utility-scale battery projects sited on radial lines or near substations to enhance resilience and defer traditional grid upgrades. As a leader in adopting emerging technology, Cobb EMC is also seeking funding for further distribution energy resource management systems (DERMs) to pilot and deploy.
Minnesota Valley Electric Cooperative (MVEC) (Minnesota)	MVEC is pursuing an early-stage campus microgrid project. Under the Microgrids for Community Affordability, Resilience, and Energy Decarbonization (MGCARED) DOE OCED grant in collaboration with NRECA, MVEC proposed installing a microgrid of between 2-4 MW at a substation in 2025 to test the use of microgrid technology as an alternative to traditional transmission infrastructure. Their project illustrates an emerging trend in resilience planning of using DERs to localize load and reduce dependency on centralized infrastructure.
Holy Cross Energy (Colorado)	Holy Cross Energy is deploying microgrids to improve grid resilience against wildfires in Aspen. Holy Cross Energy's microgrids provide backup power to critical infrastructure by isolating segments of the grid and reducing community vulnerability during wildfire events. In addition, Holy Cross deploys a mobile generation fleet to provide backup power to community centers.
Connexus Energy (Minnesota)	Connexus is exploring DER deployment through its Solar-HERO initiative, developed with NREL and the Great Plains Institute. They are evaluating the feasibility of integrating DERs into grid restoration workflows and their ability to facilitate faster restoration times. As part of this analysis, Connexus Energy utilizes AMI and outage data to enhance their visibility onto the system.
VELCO (Vermont)	VELCO is working closely with Vermont's distribution utilities to support the integration of over 50 MW of virtual power plant (VPP) capacity to enhance grid flexibility across the state. As a transmission-only utility, VELCO has established a transmission-distribution (T&D) interface that allows for coordinated DER integration and flexible load management and is intended to facilitate the growth of DERs and microgrids in Vermont.

Source: SEPA (2024).

Conclusion

Co-ops are well positioned to take a community-centered approach to enhancing resilience in a rapidly changing energy and environmental landscape. CWith new planning options and new tools and technologies, co-ops can drive initiatives and deploy solutions that meet the needs of their members.

This resilience playbook provides co-ops with actional insights and case studies, developed through workshops and interviews, that showcase the approaches some co-ops are taking to enhance their system's resilience. These approaches include those that are more traditional,such as: vegetation management, grid-hardening, and community engagement. They also include more advanced or newer initiatives, such as: the adoption of microgrids & DERs, the development of strategic plans that incorporate load growth and resilience metrics to guide investments, and the development of comprehensive natural disaster resilience strategies.

By applying these tools and lessons learned from their peers, other co-ops can build a more robust and flexible planning process that incorporates natural hazards and critical infrastructure. Co-ops also can leverage the specific actions that others have taken to enhance resilience planning—including data and system integration, member engagement and partnerships, and new strategies—to support their efforts to find affordable, equitable, and sustainable options. Ultimately, this playbook can be used by electric co-ops not only to navigate the energy challenges of today but also to plan for a more resilient and sustainable future.

Appendix A: Utility Case Studies

This appendix presents insights on resilience planning drawn from discussions with several co-ops across the country. These real-world examples provide practical strategies for optimizing investments, making balanced operational decisions, and enhancing member services.

The insights shared here support co-ops in meeting growing consumer demand, addressing resilience needs, and advancing decarbonization and equity goals, all while maintaining reliable and affordable service.

Table 7. Case Studies with Focus Indicated

Utility	Drivers	Integrating Data Systems	Engagement, Partnerships, & Funding	Vegatation Management	Grid Hardening	Microgrids and DERs
Bon Homme-Yankton Electric Association (BHYEA)					■	
Central Virginia Electric Cooperative (CVEC)		■		■		
Cobb EMC			■			■
Connexus Energy		■			■	■
Holston Electric Cooperative (HEC)			■			
Holy Cross Energy	■					■
La Plata Electric Association (LPEA)	■		■	■		
Kenergy		■		■		
Minnesota Valley Electric Cooperative (MVEC)						■
South Central Power (SCP)	■	■	■			
Southern Maryland Electric Cooperative (SMECO)	■					
Utilities District of Western Indiana (UDWI)		■	■			
Vermont Electric Power Company (VELCO)	■	■	■			■

Source: SEPA (2024).

Case Study: SMECO

Policy-Driven Distribution System Planning Requirements Ahead for Electric Distribution Cooperatives

Overview

Several co-ops across the U.S. are regulated by Public Utilities Commissions (PUCs). For instance, Southern Maryland Electric Cooperative (SMECO) is regulated alongside the Investor-Owned Utilities (IOUs) by the Maryland Public Service Commission (PSC). This is less common but also is seen across the U.S. for some co-ops in Virginia, Delaware, California, South Dakota, and Minnesota. Notably, the state allows Choptank Electric Cooperative to self-regulate like a traditional co-op, but many of the PSC's requirements that apply to SMECO do not apply to them.

In Maryland, recent legislative changes enacted through Senate Bill 1083 (SB 1083) are shaping how utilities, like SMECO, plan their distribution system. The focus is squarely on improving reliability and resilience while keeping equity in mind. Modernizing distribution system planning processes to focus on resilience and reliability while also taking equity into account is a policy trend that co-ops are starting to prepare for in Maryland and across the U.S.

Legislative and Regulatory Changes

SB 1083 requires all utilities regulated under the Maryland PSC to submit updated distribution system plans. The requirements call for SMECO to expand on traditional methods to meet modern demands while incorporating resilience and sustainability. These plans must factor in rising demand for electricity, with a focus on:

- Detailed load forecasting to predict where demand will increase.
- Collaboration with gas companies to foster a more integrated approach to energy.
- Strategic placement of distributed energy resources (DERs) like solar and battery storage to bolster grid flexibility.

Resilience and Reliability at the Forefront

Resilience and reliability in distribution system planning are focal points of SB 1083. Utilities are now required to address both reliability (ensuring power stays on) and resilience (the ability to bounce back from disruptions). Utilities are now reviewing the entire process internally to ensure compliance and reporting adheres to the new requirements.

Focus on Overburdened Communities

SB 1083 also emphasizes that distribution system investments must also be deployed within overburdened communities—areas where economic and environmental challenges compound energy reliability issues. These areas will receive priority from the Commission in terms of infrastructure upgrades, meaning utilities will have to identify areas where the system is most vulnerable and take steps to shore up its defenses.

Best Practices

Co-ops can begin exploring new tools and technologies to adapt system planning in preparation for policy-driven mandates seen in Maryland, including potential activities such as conducting more granular load forecasting, reinforcing resilience in areas that are most vulnerable to outages and extreme weather, prioritizing upgrades in overburdened communities, and identifying optimal locations for DERs to strengthen the grid.

How SMECO is Preparing for New Processes Around Distribution System Planning:

- Exploring more DERs, such as energy storage and electric vehicles (EVs) and adoption strategies to lower greenhouse gasses and improve reliability.
- Expanding DER and EV infrastructure in disadvantaged areas while integrating energy-saving measures across the distribution system.
- Planning for and managing anticipated increases in electricity demand, while implementing solutions to handle variable loads efficiently.
- Strengthening grid reliability to manage disruptions, enabling bidirectional power flows, and leveraging demand response for system improvements.
- Leading active stakeholder participation and adapting to evolving regulatory requirements.

Case Study: South Central Power

Game Plan for a Stronger Grid

Introduction

South Central Power (SCP), Ohio's largest co-op, is driving grid reliability and resilience through strategic investments and active community engagement. With a network spanning 11,848 miles of distribution and transmission lines—including 3,258 miles of underground distribution and 263 miles of transmission lines—SCP serves over 131,000 meters across its service territory. This case study examines SCP's approach to navigating the complexities of system growth and aging infrastructure, highlighting its commitment to innovative solutions and a resilient, dependable grid for its members.

Strategic Approaches and Best Practices to Solving Challenges

SCP is tackling grid resilience and reliability with a forward-looking opportunistic mindset in solving challenges.

In addition to these approaches, SCP regularly gathers feedback from members and stakeholders for project alignment and grant funding. This often includes leveraging community partnership to secure letters of support for grant applications to obtain state and federal funding.

Strategic Investments in Grid Resilience and Automation

Since 2017, South Central Power (SCP) has embarked on a series of phased, multi-year investments to modernize its grid infrastructure, enhance resilience, and improve service reliability. These projects focus on implementing advanced metering infrastructure, upgrading SCADA systems, and deploying automation technologies.

Advanced Metering Infrastructure (AMI) and DA Device Rollout

In 2018, SCP began deploying Point-to-Multipoint (P2MP) Advanced Metering Infrastructure (AMI) with Sensus, designed to improve remote communication and system management. This project is organized in multiple phases:

- Installed over 170 base stations to support AMI.
- Deployed more than 120,000 advanced meters across the service area.
- Deployed over 150 distribution automation (DA) devices to enhance remote control and monitoring capabilities.

SCADA System Upgrades and Communication Enhancements

To improve operational efficiency, SCP transitioned from the ACS SCADA system to Survalent, enhancing its ability to monitor and control the grid.

- Converted and commissioned both existing and new equipment for over 75 substations and delivery points.
- Deployed 290 SEL (Schweitzer Engineering Laboratories) devices.
- Integrated 400 Eaton Cooper devices for robust data collection and control.
- Established and commissioned communications for over 125 line devices and capacitor banks to assist with power factor correction at more than two dozen locations.
- Redesigned the SCADA network to include dedicated servers for production (main and backup), development, training, and historical data management.

Automation and Fault Management Initiatives

SCP is also focusing on localized automation and fault management to improve response times and minimize outages.

- Implemented script-based automation on some transmission and critical distribution feeders.
- Actively working with the SCADA system to integrate FLISR capabilities, reducing dependence on localized automation that requires significant resources to maintain.

Table 8. SCP's Strategic Approaches to Resilience Planning Challenges

Challenges	Details	Solutions
Limited Communication Infrastructure	SCP lacks fiber technology, relying on SCADA systems to monitor performance. Without fiber, real-time data management is limited.	▪ Actively working on fiber infrastructure, focusing on high-speed internet service to the home, bringing broadband to rural Ohio Communities. ▪ Crafting plans to best use facilities for communication, distribution automation and transmission relay protection in electric plants. This includes AMI and FLISR systems that help SCP automatically reroute electricity during outages, reducing downtime. ▪ Awarded a broadband Ohio grant from Public Utilities Commission of Ohio Grid Resilience Grant Case No. 22.755-AU-COI to support.
Prioritizing Projects	Aging equipment, increasing power demand, and a limited budget create challenges in deciding which upgrades to tackle first.	▪ Developed the "Future Strategic Plan" to evaluate project prioritization tools to aid with reliability project prioritization. ▪ Current drivers are defined criteria violation, load growth, member driven, and outage driven (duration and/or times out). ▪ Other factors include upgrades for essential services (hospitals, fire stations, etc.) and underserved communities.
Overhead vs. Underground Lines	Overhead lines are vulnerable to weather but cheaper, while underground lines offer more protection but are more expensive to install.	▪ Conducted a deep dive into outage data, causes, and potential solutions to minimize impact. ▪ Considering initial cost, upkeep cost, terrain, accessibility challenges to identify the mode adequate approach (overhead or underground).
Financial Pressures	With the rise of data centers, SCP is revisiting its pricing structure to balance new load requests and ensure fair rates for members.	▪ Established a rate committee and enacted rate changes April 1st, 2024 expanding commercial rate classes from two to four.
Managing New Load Requests	SCP prioritizes new business requests based on their system impact, particularly from the growing data center industry in Ohio.	▪ Implemented a revised commercial application process. ▪ Future Strategic Project in Support of Economic Development request. ▪ Top sites preliminary evaluation utilizing hosting capacity functionality in engineering analysis (EA) tool.

Source: SCP (2024).

Case Study: La Plata Electric Association

Strategic Path to Resilience in Colorado

As extreme weather events grow more frequent, La Plata Electric Association (LPEA), an electric cooperative distribution utility based in Colorado, is balancing rural and urban service needs, peak demand growth, and regulatory challenges. With high solar penetration, they've faced grid capacity issues and are actively improving resilience. LPEA navigates local generation limits, new rate structures, and behind-the-meter (BTM) technology integration. As they prepare for more independence from Tri-State by 2026, they expect to improve management of over local generation and DER integration.

Lessons Learned

- LPEA's move away from Tri-State emphasizes the need for flexibility in local generation, balancing resilience with cost-effective solutions.
- LPEA envisions its future role as a Distribution System Operator (DSO), managing DERs and purchasing power independently.
- Collaboration with utilities and national programs has been key to LPEA's success in resilience planning.

Table 9. Challenges, Successes and Opportunities for LPEA

Challenges	Details
Regulatory Cap on Local Generation	Tri-State's 5% cap limits DER scaling. LPEA plans to expand local energy generation after leaving Tri-State in 2026.
Solar Interconnection and Backfeeding	With ~3,000 solar interconnects across 49,000 meters, LPEA faces significant grid management issues.
System Planning	Aging infrastructure and increasing electricity demand due to electrification and other commercial growth highlights the importance of updated system planning processes and techniques.
OEM & Technology Maturity Issues	Technological limitations affect control over BTM loads, impeding LPEA's shift from situational awareness to operational control.
Seasonal Peaking Challenges	Both summer and winter peaks complicate demand management, increasing the need for sophisticated resilience strategies.
Solutions	**Details**
Utilize Innovative Rates to Manage Grid-Edge Projects	Offering a peak demand charge that incentivizes members (members not on the TOU rate) to shave their peak, resulting in an overall reduction in system demand during peak times.
Integrating DERs into Distribution System Planning	Deploying a 10 MW / 40 MWh front-of-meter battery storage project to improve grid stability and defer a $30M+ transmission investment.
Enhance Operational Efficiency of DERs	Exploring feeder-level controls to optimize DERs to prevent backfeeding and to increase grid capacity (e.g., VPPs) and conducting feeder-level load forecasting on feeders with high solar penetration to help manage peaks.
Refocus DERMs for OEM Integration	LPEA piloted two DERMs systems and has decided to only use them for direct connections with OEMs and not for managing grid-edge projects.
Scaling Battery Storage and BTM Solutions	Expand battery storage and BTM solutions for daily load management and peak demand reduction.

Source: LPEA (2024).

Opportunities with Pay-for-Performance and Local Generation Expansion

To enhance responsiveness to energy market signals, LPEA plans to implement pay-for-performance incentives by 2026. This initiative will reward demand response and energy efficiency efforts, enabling optimized energy use aligned with grid needs and supporting members in reducing energy costs. By 2026, LPEA also intends to ramp up investments in renewable energy and resilience-enhancing technologies, expanding local generation capacity, decreasing reliance on external power sources, and fostering a cleaner energy mix for co-op members.

Key Partnerships & Investments

LPEA attributes its continued progress to several key partnerships and investments to advance resilience planning and renewable energy integration.

- Partnered with La Plata County on the utility-scale solar and battery storage project which helped create the low-moderate-income member facing solar garden, adding renewable generation capacity while maintaining resource adequacy.
- Partnered with the Southern Ute Tribe to install smart reclosers and vacuum reclosers throughout the most outage prone areas of their Tribal lands.
- Partnered with National Renewable Energy Laboratory (NREL) to build a physical model to run reverse power flow experiments and feeder-level load forecasting for solar-overloaded feeders to facilitate DER integration.
- Secured various grants for resilience investments through U.S. Department of Energy, Colorado Energy Office, Colorado Department of Local Affairs, Lawrence Berkeley National Laboratory, and Property Assessed Clean Energy.
- Partnered with NRECA and Holy Cross Energy to support and enable wildfire mitigation and resilience investments.
- Partnered with satellite imaging and drone companies to enhance vegetation management and inspections to help mitigate wildfire risks.

Measuring Success

To measure the success of LPEA's various resilience initiatives, they have established metrics to measure success and ensure alignment with its long-term goals.

Table 10. LPEA Example Metrics for Resilience Planning

Metrics	Description
Peak Load Reduction	Peak demand and forecasts load reductions from demand response programs and device capabilities.
ROI on Programs	Payback period and evaluating strategies based on meter-level demand response data.
Daily DERMS Use	Peak-day DERMS usage to daily operational control and ability to maximize DER fleet usage.

Source: LPEA (2024).

Case Study: Central Virginia Electric Cooperative

Operational Resilience in Action: Immediate Impact Strategies for Central Virginia

Overview

Central Virginia Electric Cooperative (CVEC), like many co-ops, faces growing pressure to maintain reliable electric service amid aging infrastructure, geographic difficulties, and increasingly frequent extreme weather events.

This case study explores CVEC's resilience approach, focusing on the use of Geographic Information Systems (GIS), Advanced Distribution Management Systems (ADMS), Distributed Energy Resources (DERs), and the Firefly fiber network to improve grid reliability and resilience.

Table 11. Overview of CVEC

Service Area	Details
Geographic Coverage	▪ 14 counties over 1,609 square miles (mountainous terrain, dense forests).
Infrastructure	▪ 4,805 miles of power lines serving 39,446 meters (8.21 meters/mile). • Overhead Circuits: 2,924 miles (primary), 303 miles (secondary), 72 miles (transmission). • Underground Circuits: 920 miles (primary), 586 (secondary).
Key Technology	▪ Firefly fiber network for remote control and automation provides remote control and automation of smart grid devices. • Improves outage resolution without requiring personnel to visit faults. • Reduces restoration times, especially in remote, mountainous areas. ▪ Advanced Metering Infrastructure (AMI) and SCADA for real-time outage management across substations • Improves real-time monitoring. • Improves grid management.

Source: CVEC (2024).

Table 12. Key Challenges for CVEC for Resilience Planning

Challenges	Details
Frequent Outages Due to Environment	Dense forests and mountainous terrain contribute to frequent outages from tree falls and vegetation overgrowth. In particular, tree-related outages remain a top cause of interruptions in the service area. ex) Tree failure outside right-of-way (ROW) is the number one cause of outage, causing 65% of all outages.
Infrastructure Vulnerabilities	Long overhead circuits, such as Circuit 501, are particularly vulnerable to outages due to tree-related issues, with the first protective device 11.59 miles from the substation. In 2022, five poles on Circuit 501 were damaged by falling trees despite being installed relatively recently (2010-2014).
Aging Infrastructure	The damage to newer poles has prompted the need for stronger materials. CVEC is upgrading poles in mountainous regions where tree falls present a continuous risk. ex) Material and equipment failure is the number two cause of outage, causing 13% of all outages.

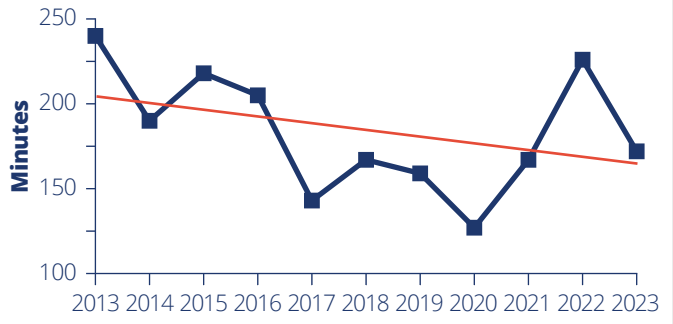
Source: CVEC (2024).

Table 13. CVEC's Data-Driven Decision Making for Industry Benchmarks	
Metrics	**Details**
SAIDI, CAIDI, SAIFI	CVEC uses these standard reliability metrics to prioritize investments in the worst-performing circuits. CVEC focuses annually on the bottom 10% of its circuits to ensure resource allocation has the highest impact.
Industry Benchmarks (EIA)	Typical U.S. utilities have 100-150 SAIDI minutes annually, while rural co-ops average 200-400 minutes. CVEC's worst-performing circuits exceed 4,000 minutes, highlighting the need for targeted resilience strategies.
Planned SAIDI Improvements	CVEC aims to reduce SAIDI values to the 500-1,000 minute range on its worst-performing circuits through a combination of vegetation management, grid automation, and battery storage investments over the next few years.

Source: CVEC (2024).

The steady drop in SAIDI minutes is due to a variety of resilience measures, namely the emerging Integrated Vegetation Program investment and the transition to a 5-year vegetation management cycle. A full timeline of the evolution of CVEC's vegetation management program is shown in Table 14.

Figure 6. SAIDI Minutes for CVEC's Selected Worst Performing Circuit

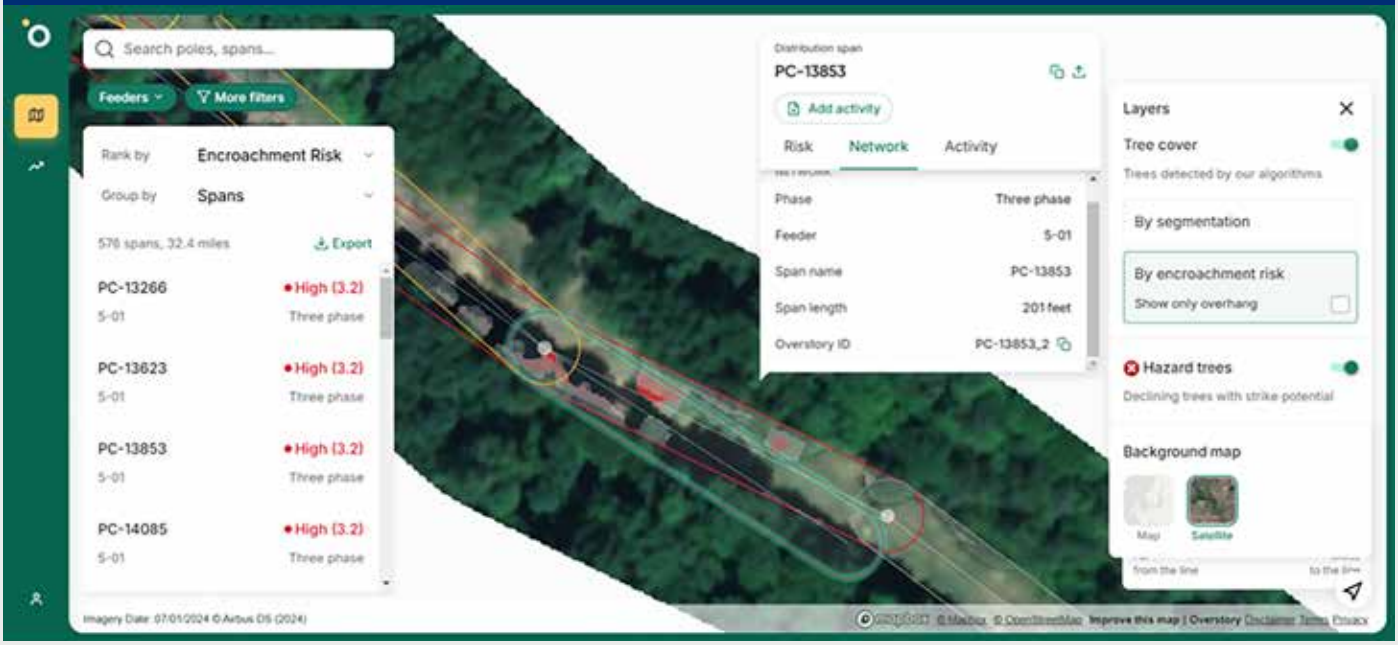


Source: CVEC (2024). Recreated by SEPA.

Table 14. Vegetation Management Timeline	
Year	**Action**
1998-2002	Minimal side trimming and limited spraying.
2003	Budget increase for side trimming and helicopter trimming introduction.
2015	Budget increase and implementation of complete cycle spraying.
2019	Transition to a 5-year vegetation management cycle.
2023	Pilot satellite scans to identify off-schedule trimming needs.
2024	Full-scale deployment of satellite-based vegetation management.

Source: CVEC (2024).

Figure 7. Example of Satellite-Based Vegetation Management for Circuit 501



Source: CVEC (2024).

Table 15. CVEC's Additional Resilience Measures

Measure	Description
Satellite-Based Vegetation Management	In 2023, CVEC launched a pilot program to identify high-risk circuits using satellite data. This program was successful, and full-scale deployment is planned for 2024 to reduce outages caused by overgrown trees. Satellite data helps CVEC focus on circuits most prone to vegetation-related outages, especially those not part of the regular five-year maintenance cycle. For a full case study published by CVEC on lessons learned from this program, see the Appendix: Overstory Pilot and Lessons learned.pdf
Battery Storage at Key Substations	CVEC is moving forward with battery storage projects at Piney River and Collen substations to support peak demand and resilience. These battery systems will help defer the need for costly transmission infrastructure upgrades while improving grid stability during peak periods. CVEC re-engaged with contractors in 2023 due to improved return on investment (ROI).
Automation of Sectionalizing Devices	Automating sectionalizing devices on long circuits (like Circuit 504) to reduce restoration times and prevent outages. Automation could have prevented outages for as many as 127 customers during faults on Circuit 504.
Infrastructure Upgrades	CVEC is replacing aging copper wiring and upgrading poles in mountainous areas to improve resilience and reduce maintenance costs. Stronger poles are being installed in areas prone to tree falls, especially in mountainous regions where accessing fault locations is difficult.
Targeted Circuit Patrols and Sectionalizing Efforts	▪ Circuit 501: Targeted patrols for danger trees and automating sectionalizing devices to reduce outage impacts along its 154-mile span. ▪ Circuit 504: Increased patrols for tree risks and sectionalizing implementation to reduce customer outages outside the right-of-way.

Source: CVEC (2024).

Battery Energy Storage Systems (BESS) at Substations Explained

CVEC conducted an analysis on peak demand for each substation to decide where they would get the most benefit. In 2023, the peak demand for electricity in kilowatts (kW) at two delivery points, Piney River and Colleen, fluctuated significantly across the months. For Piney RIver, the highest demand occurred in February at 6,701 KW, followed by March with 5,834 kW. The demand decreased to its lowest in May, at 3,088 kW and the year closed with 5,949 kW in December. For Colleen, the demand peaked in November, with other high points in October (7,838 kW) and September (6,700 kW). The lowest demand for Colleen was in May at 3,885 kW. Generally speaking, the demand at Colleen mirrored Piney River's trend. This 2023 peak demand data was analyzed to guide decisions on deploying BESS at substations. By identifying the months with the highest power demand at the Piney River and Colleen delivery points, CVEC was able to prioritize locations that would benefit most from added storage capacity. The data shows critical demand peaks in February for Piney River and in the last quarter for Colleen, indicating these substations may be ideal candidates for BESS deployment to support grid stability and manage peak loads efficiently.

Table 16. CVEC's Best Practices and Lessons Learned for Resilience Planning

Practice	Details
Data-Driven Prioritization	CVEC targets its worst-performing circuits based on SAIDI, ensuring resources have the greatest impact.
Pilot Programs for New Technologies	Testing satellite-based vegetation management before full-scale rollout minimizes risks and maximizes benefits.
Proactive Infrastructure Upgrades	Replacing aging copper wiring and upgrading poles improves resilience, especially in hard-to-access areas.
Circuit-Specific vs. System-Wide	CVEC balances immediate improvements on worst-performing circuits (like vegetation management) with long-term system-wide investments (like battery storage and grid automation).
Member Engagement	Regular surveys and feedback help shape CVEC's resilience strategy, achieving a 91% member satisfaction score.
Emerging Technologies	CVEC explores AI-driven monitoring, weather forecasting, and wildfire risk prediction to manage system vulnerabilities proactively.

Source: CVEC (2024).

Case Study: Connexus Energy

Blueprint for Grid Resilience

Connexus Energy's smaller footprint and meter count allows it to facilitate data sharing for resilience planning and shares all of its outage and AMI data to improve system visibility and restoration workflows during power outages.

Solar-HERO Initiative

- Collaborated with NREL and Great Plains Institute to integrate DERs into grid restoration workflows and to utilize DERs and load flexibility for faster recovery during outages.
- Included sharing several years of AMI data and all outage data, which allows for analysis and enhanced system recovery processes.
- Conducted stakeholder interviews to identify scalable, replicable DER-based resilience solutions

Based on its 2023 reporting, Connexus achieved its best reliability performance in history, consistently ranked in the top 1% of utilities in the U.S., driven by proactive resilience and infrastructure investments.

Connexus is focused on differentiating between outage factors from transmission and distribution networks to optimize grid performance. Learning from wildfire-related disasters caused by IOUs in Hawaii, Texas, and Colorado, Connexus aims to avoid underinvestment in grid maintenance.

Table 17. Connexus Energy Overview

Service Area	Details
Geographic Footprint	Connexus Energy serves approximately 150,000 meters
Resilience Partnership	Collaborating with NREL, Great Plains Institute on DOE-funded resilience project
Key Project	Solar-HERO: Using DERs to accelerate grid recovery

Source: Connexus (2024).

Table 18. Connexus Energy's Resilience and Reliability Metrics and Performance

Metric	Details
SAIDI and SAIFI	Connexus ranks in the top 1% of U.S. utilities, consistently in the top 3% for SAIFI.
2023 Performance	Achieved best reliability in modern history.
Prioritized Improvements	Focused on members with three or more outages annually, ensuring prioritized service improvements.

Source: Connexus (2024).

Table 19. Connexus Energy's Infrastructure Investments for Resilience

Initiative	Details
10-Year Infrastructure Plan	Connexus is in year 2 of a 10-year plan, replacing overhead backlot power lines with underground service.
Annual Plan	Undergrounding power lines for approximately 400 lots per year, reducing weather-related outage exposure. This ongoing infrastructure upgrade involves moving overhead lines underground.

Source: Connexus (2024).

Case Study: BoxPower and Holston Electric Cooperative

Enhancing Electric Cooperative Resilience Planning through Mapping Tools

BoxPower's Microgrid Integration Survey (MGIS), a machine-learning and AI-driven tool, helps co-ops identify, evaluate, and prioritize resilience investments, offering low-cost, data-driven solutions.

MGIS uses over 70 parameters, including co-op provided distribution system GIS data and public data sets, to help co-ops make informed decisions about resilience investments. It is a tool accessible to electric utilities that overlays data from sources such as FEMA's National Risk Index, Distressed Communities Index, and Justice40 criteria to help prioritize investments. Key features include:

- Enables utilities to visualize GIS data with multiple data inputs and overlays, including line assessments and critical infrastructure.
- Helps co-ops identify optimal microgrid locations using a combination of reliability, land use, customer-to-line mile ratios, and socio-economic data.
- Allows co-ops to evaluate resilience solutions, from traditional grid hardening to advanced microgrid integration and DERs.
- Identifies cost-effective alternatives to substation investments through microgrid deployment.
- Aligns resilience projects with federal programs like the Inflation Reduction Act and Infrastructure Investment and Jobs Act (IIJA) for potential funding opportunities.
- Provides data to support rate justifications and cost-benefit analyses for project approvals.

Holston Electric Cooperative (HEC) Use Case

Holston Electric Cooperative (HEC) in Tennessee faces significant challenges with reliability and power quality on some of its circuits. Traditional solutions like a multi-million substation investment were considered but rejected due to their costs. HEC and BoxPower collaborated to scan HEC's worst-performing circuits to identify optimal microgrid integration opportunities that would improve end-of-line reliability along with grid services for the broader HEC membership. The MGIS analysis was done as the first phase of BoxPower's microgrid integration program. After identifying potential integration opportunities, a design study is conducted to develop the techno-economics of each potential site, providing details on construction, costs, and timelines.

Table 20. Challenges for HEC Addressed by MGIS

Challenges for HEC	MGIS Identified Solutions
Avoiding Upgrade Cost	MGIS helped identify microgrid locations along Holston's three worst-performing circuits, avoiding a costly substation investment.
Grid Services and Cost Reduction	The MGIS tool allowed HEC to identify specific microgrid integration opportunities on its distribution system that provided peak shaving and demand charge management while accessing grant funding to reduce member costs.

Source: BoxPower (2024).

Case Study: Kenergy

Embracing Innovation, Broadband, and Strategic Partnerships for Grid Resilience

Kenergy, a co-op serving western Kentucky, is rethinking its traditional utility approach by leveraging broadband access, distributed energy resources (DERs), and strategic partnerships to advance grid resilience. With a "blank slate" for DER program development, Kenergy is building solutions from the ground up, focusing on demand response, distributed solar PV, and utilizing emerging technologies like batteries and electric vehicles (EVs) on their grid. Through gatherings with its generation and transmission (G&T) members and partnerships, Kenergy is exploring new tools, techniques, and technologies for resilience. Key activities include:

Broadband and Data Integration

- Deploying fiber-optic broadband across its entire membership, enabling a shift in managing and utilizing resources. Reliable broadband is essential, supporting everything from smart grid applications to IoT communication in member homes. Devices like the Emporia Smart Home Energy monitor are being tested to gather granular data on home energy use, especially with DERs connected to HVAC systems, EVs, and other home devices.
- Combining data with aggregated smart meter insights to lay the groundwork for virtual power plant (VPP) options to benefit G&T utility operations and the broader energy market.
- Visualizing historic outage data to enable more targeted maintenance and prioritize investments based on data-backed insights rather than simply age-based or material-based approaches.

DER Integration and Grid Flexibility

- Developing programs that leverage small contributions from members—about 1.6 kW of load per meter to reach their initial goal of 100 MW of DER capacity. Currently, around 67% of a home's non-coincident peak (NCP) aligns with Kenergy's system peak, making demand response a primary opportunity for resilience and cost savings.
- Exploring distributed solar, batteries, and EVs, to contribute to a more responsive and flexible grid. Integrating these resources reduces reliance on external energy sources and allows Kenergy to buy locally generated power before relying on the external market, running gas plants, or building new resources.
- Keeping up with the MISO rulings around DER aggregation to maintain a focus on reliability while mitigating the need for mandatory load shedding during critical periods.
- Pairing traditional SCADA systems with IoT devices for DER management to facilitate a flexible, self-sustaining grid that enhances both operational efficiency and member resilience.

Resilience and Maintenance

- Testing advanced technologies to support grid resilience, such as pairing artificial intelligence with imagery for targeted vegetation management—focusing on high-risk areas instead of broad rotations. LIDAR paired with drone applications helps map and inventory electric and fiber infrastructure, enhancing system reliability and safety.
- Exploring the potential for neighborhood microgrids that could operate independently for short periods, enabling parts of feeders to be de-energized for faster, safer, and more efficient maintenance. These microgrids would also help ease the impact of long outages during severe weather events.
- Identifying ways to connect its system to neighboring grids, adding resilience and flexibility during system maintenance.

Partnerships and Innovation

- Finding operational efficiencies that free up funds for further innovation, especially within a rate-regulated environment that limits direct investment in new technologies.
- Engaging with key partners where direct innovation investment is challenging given the regulated environment.
- Collaborating with their G&T and other co-ops to fund, test, and market DER and resilience programs more effectively.
- Collaborating with organizations like NRECA for educational resources and insights on federal funding opportunities to help shape innovative programs that support resilience and reduce the need for load-shedding during critical times.

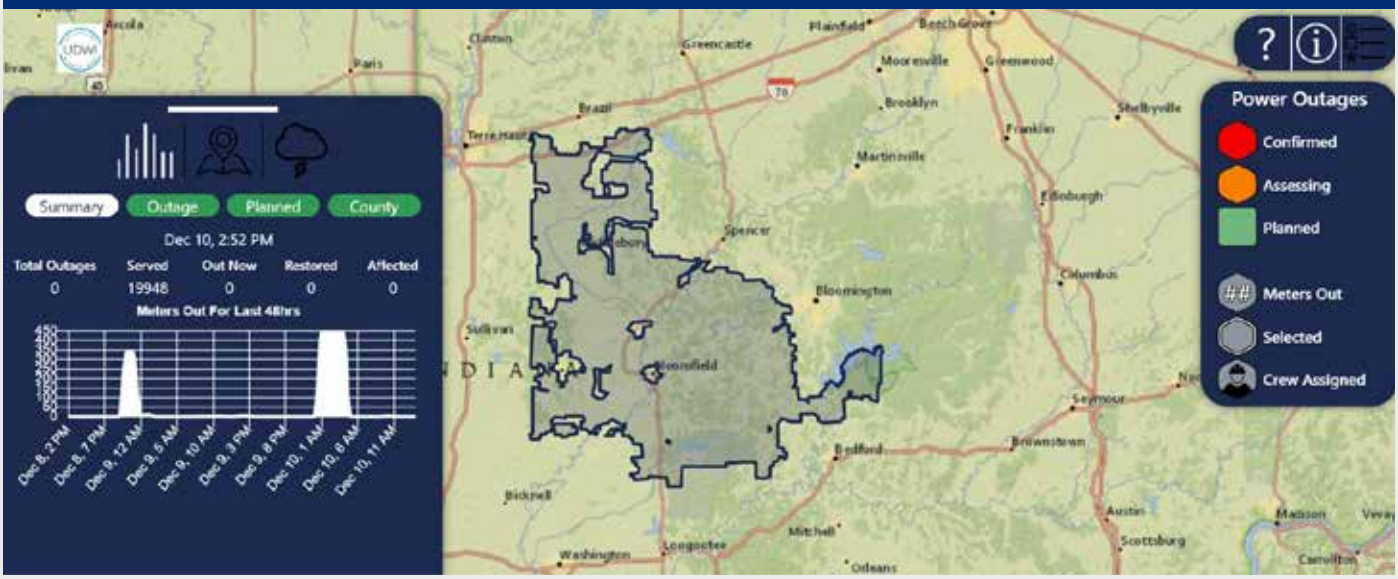
Case Study: Utilities District of Western Indiana REMC

Leveraging Technology for Fault Detection and Data Integration

UDWI, which serves primarily rural areas near Bloomington, Indiana, has focused on enhancing grid reliability by integrating advanced systems such as GIS (Geospatial Information Systems), EA (Engineering Analysis), OMS (Outage Management System), SCADA (Supervisory Control and Data Acquisition), and Power Solutions Distribution Fault Anticipation (DFA) product. Key learnings include:

- The DFA product helps identify downline faults that SCADA systems alone cannot track, such as disturbances that do not trigger breaker operations. This more granular fault information allows UDWI to address issues proactively before they escalate into outages.
- Accurate GIS and EA data is critical. By integrating GIS, EA, OMS, SCADA, and DFA, UDWI pinpoints recurring faults to optimize resource allocation and improve overall grid reliability and resilience.
- UDWI has undertaken a long-term initiative to increase customer enrollment as a customer of Meridian Cooperative's engagement platforms, leveraging text notification programs to reach their member customers. UDWI also leverages AMI systems and the NISC platform to support enhanced data collection for improving reliability and resilience.

Figure 8. Snapshot of Outage Management System



Source: UDWI REMC (2024).

Case Study: Bon Homme-Yankton Electric Association

Resilience in a Small Cooperative

Bon Homme-Yankton Electric Association (BHYEA) is a small co-op in South Dakota focusing on undergrounding its distribution lines as a key resilience measure while facing constraints on expanding solar and energy storage deployment due to transmission contracts and cold weather challenges. Key activities include:

- Prioritized undergrounding about 30 miles of its distribution lines per year, a strategy aimed at reducing outage risks from storms and other natural disturbances. This gradual effort is their primary focus for improving resilience.
- Due to existing transmission contracts, BHYEA has been limited in expanding distributed generation, with only three consumer-owned solar PV systems deployed. Concerns about energy storage's performance in cold climates further hinder the co-op's ability to adopt storage technologies.
- BHYEA uses NISC's Outage Management System (OMS) and AMI systems to improve visibility and manage its grid. These tools have proven invaluable for mapping and operational efficiency.
- As a smaller co-op, BHYEA faces financial limitations, and its grants are prioritized based on maximizing the benefit to the largest number of consumers. Financial assistance is therefore focused on projects that provide the most impact per dollar, ensuring that every investment directly benefits consumers on the line.

Case Study: Minnesota Valley Electric Cooperative

Exploring Microgrids as Transmission Alternatives

Minnesota Valley Electric Cooperative (MVEC) is in the early stages of exploring the deployment of a campus microgrid, potentially as an alternative to traditional transmission infrastructure, while continuing to expand its renewable energy installations. Key insights include:

- With 400 installations and 5 MW of distributed energy resources (DERs) already on its system, MVEC is evaluating the feasibility of a campus microgrid. The microgrid could serve as an early-stage alternative to building new transmission lines, providing resilience and flexibility in the face of grid challenges.
- As MVEC moves forward with microgrid planning, the co-op seeks to balance reliability improvements with future load growth. The exploration of microgrids highlights the potential of these systems to support localized grid resilience, reduce dependence on larger transmission networks, and offer a more cost-effective solution in specific scenarios.
- MVEC is currently collaborating with the National Rural Electric Cooperative Association (NRECA) as part of a consortium utilizing the MGCARED DOE Office of Clean Energy Deployment (OCED) Grant to install a 2-4 MW microgrid at one of its substations. While this project is still in its infancy and much of the planning and design will occur in 2025, it represents a crucial step in MVEC's ongoing efforts to assess the feasibility and effectiveness of microgrids as an alternative to traditional infrastructure. This microgrid initiative is designed to help MVEC advance the reliability of its distribution system by testing the integration of DERs with grid operations, serving as a pilot to determine the long-term viability of microgrids in maintaining grid stability, particularly in rural areas served by co-ops.

The community—in an area with growing population—is served by a single transmission line, and the microgrid will provide redundancy, resilience and clean energy. MVEC looked at installing another line but found that it was nearly impossible to find easements that would allow for the line. And that option was too costly."

—MIKE DIETZ, VICE PRESIDENT OF OPERATIONS, MVEC

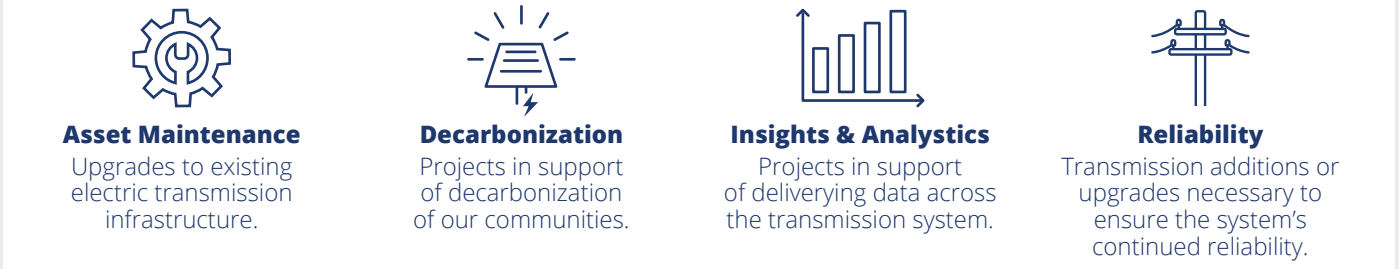
Case Study: Vermont Electric Power Company

Strengthening Resilience through Transmission-Distribution Collaboration

Vermont Electric Power Company (VELCO) is Vermont's transmission-only owner, planner, and operator serving their 17 distribution utility customer-owners across the state. VELCO improves resilience and reliability by working collaboratively across the T&D interface. VELCO's for-profit structure delivers co-op-like value to every grid-connected customer (e.g., VELCO profits lower Vermont electric customers' rates). VELCO is responsible for meeting NERC contingency analysis standards, which require greater levels of situational awareness and operational coordination. Their efforts are underpinned by advanced technologies, including a statewide, 1,600 mile fiber-optic network. VELCO is working with Vermont's distribution utilities to collaboratively prepare for the proliferation of virtual power plants (VPPs) so that operators can continue to deliver safe, reliable, affordable, and sustainable transmission service. Key insights include:

- VELCO must adhere to NERC standards, utilizing contingency analysis models to prepare for potential system failures (e.g., N-1 contingencies). Reliability metrics such as SAIDI and Sustained Forced Outages help monitor system performance and inform infrastructure improvements.
- Vermont distribution utilities operate over 50 MW of virtual power plant capacity in Vermont. These VPP programs facilitate integration of distributed energy resources (DERs), providing new tools for distribution utilities to enhance grid flexibility and reliability.
- By maintaining situational awareness and clear signals between operators, VELCO is working to support distribution utilities as they enable flexible load management and DER integration. Their efforts include collaboratively defining roles and responsibilities between T&D operators.
- VELCO is working with PNNL and ORNL exploring ways to collaboratively use the common information model (CIM) for simulating T&D systems to enhance reliability and get more value out of the existing grid.

Figure 9. Features of VELCO Projects



Source: VELCO (2024). Recreated by SEPA.

Case Study: Cobb EMC

Leveraging Battery Storage, Automation, and Renewable Energy for Cost Savings, Resilience, and Sustainability

Cobb EMC, a co-op serving over 220,000 customers in Georgia, focuses on holistic cost savings while integrating renewable energy, battery storage, and distribution automation. By factoring in resilience and reliability, Cobb EMC aims to enhance its service while reducing risks and operational costs. Recent initiatives, including utility-scale battery storage and microgrid development, demonstrate the utility's commitment to innovative grid solutions and sustainable energy management. Key insights include:

- Implemented a proof-of-concept microgrid at their headquarters, featuring a 1.5 MW solar PV system, a 1 MW/4 MWh battery energy storage system (BESS), and a 1 MW natural gas generator. This microgrid, which also includes a solar canopy for EV charging, showcases how Cobb EMC can integrate renewable energy and battery storage to improve resilience and reliability while driving cost savings through peak shaving.
- Exploring two new utility-scale battery storage projects, with a total capacity of 20 MWh. These systems will be strategically placed on radial lines or near substations, enhancing resilience by providing backup power during outages and supporting grid stability. This focus on energy storage aligns with Cobb EMC's long-term strategy to balance cost savings, reliability, and sustainability.
- Continuing their 30-year history of implementing distribution automation technology, which they have fine-tuned to restore and maintain power efficiently across their 460-square-mile service area. The co-op's 12.4/70 kV system, paired with extensive substations, benefits from automated field devices that improve grid performance and reduce outage durations.
- Expanding its knowledge of distributed energy resources (DERs) as they continue to develop utility-scale battery storage. The integration of DERs, though complex, adds valuable tools for peak shaving and resilience. Cobb EMC aims to roll out utility-scale systems that function as self-contained microgrids, using automation and transfer schemes to isolate sections of the grid and ensure continuity without operator intervention. These systems enhance flexibility and improve overall grid management.
- Implemented strategic undergrounding of infrastructure to ensure cost-effective investments for resilience and reliability. This approach is part of a broader strategy to enhance grid performance and reduce operational risks.
- Leveraging advanced load management, battery storage, and automation technologies to defer major capital investments, such as building new substations, by 2-3 years. This deferral translates into significant cost savings for the co-op and its members, while ensuring the grid can continue to meet growing demand efficiently.
- Engaging customers regularly to participate in time of use rates to support peak demand management. As no single DERMS vendor currently offers a comprehensive solution for all customer technologies, Cobb EMC is seeking funding, including GRIP funding, for two large battery storage projects and further DERMS development. These initiatives are central to Cobb EMC's strategy of enhancing grid resilience, reliability, and cost efficiency for their members.
- Creation of a "Renewable Energy Dashboard" to highlight their commitment to clean energy, including the solar PV system integrated into their microgrid. Their renewable energy projects and tools for customers, such as the Smart Energy Program, reflect Cobb EMC's focus on sustainability and carbon reduction. The co-op's long-term goal is to reduce its carbon footprint while ensuring reliability and affordability for its members.

Case Study: Holy Cross Energy

Enhancing Wildfire Resilience with Microgrids in Mountainous Regions

Holy Cross Energy, a mid-sized co-op serving large resort areas like Vail, and Aspen, faces unique challenges operating in the wildfire-prone Rocky Mountains. In response to increasing wildfire threats, Holy Cross has prioritized microgrid implementation as a key strategy to enhance resilience for critical infrastructure and communities. Key insights include:

- Developing microgrids to improve the resilience of their distribution system, particularly around critical areas such as the Aspen airport. These microgrids, which integrate solar and battery storage, were prompted by a wildfire that nearly impacted the Aspen region. By isolating parts of the distribution system and providing backup power, the microgrids will ensure continuous service during emergencies, reducing the vulnerability of resort communities.

Figure 10. Examples of Critical Sites Identified by Holy Cross Energy



Source: Holy Cross Energy (2024).

- Operating distribution systems in the Rocky Mountains presents challenges due to terrain, weather, and wildfire risk. Implementing microgrids in such environments requires significant engineering effort and long-term planning to ensure their effectiveness and sustainability. Holy Cross Energy is deeply involved in this "heavy lift," which involves not only technical hurdles but also ensuring the long-term viability of these solutions.
- Extending their resilience approach beyond microgrids. Their strategy includes bulk supply resilience, deploying a mobile generation fleet, providing backup power for refuge centers, assessing energy needs for critical services, and ensuring gas pump functionality during emergencies. These efforts are designed to keep essential services running and minimize disruptions to resort communities during wildfire events.
- Conducting proactive resilience planning by engaging with stakeholders and conducting vulnerability assessments. Through their Roaring Fork project, they identified critical services and infrastructure at risk and investigated solutions, including community microgrids and solar installations like the Pitkin County solar project. Holy Cross also incorporates resilience into building codes, ensuring that new developments are prepared for wildfire risks.
- Collecting and analyzing key data, such as outage frequency, customer impact, and infrastructure health to guide resilience investments. These metrics help the co-op prioritize investments in resilience projects that offer the greatest benefit to customers and critical services. By focusing on data-driven decision-making, Holy Cross Energy ensures that their microgrid deployments are not only technically sound but also aligned with community needs and long-term cost-effectiveness.

Appendix B: Participating Electric Cooperative Utilities

- AECI
- Aiken Electric Cooperative
- Anza Electric Cooperative
- B-Y Electric
- Beltrami Electric Cooperative
- Central Virginia Electric Cooperative
- Connexus Energy
- Dakota Electric Association
- Elmhurst Mutual Power & Light Co.
- Flathead Electric Cooperative
- Golden State Power Cooperative
- Graham County Electric Cooperative
- Holy Cross Energy
- Kankakee Valley REMC
- Kenergy
- LPEA
- MidSouth Electric Cooperative
- Midwest Electric Cooperative
- Minnesota Valley Electric Cooperative
- Northwestern Electric Cooperative
- NOVEC
- OPD5
- Piedmont Electric Member Corp
- Poudre Valley REA
- Rayburn
- South Central Power Co.
- UDWI REMC
- VELCO
- Western Farmers Electric Cooperative
- WIN Energy REMC



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