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A new era for rural electric cooperatives: New clean energy investments, supported by federal incentives, will reduce rates, emissions, and reliance on outside power

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ABSTRACT

This paper shows a least cost electricity generation portfolio for some of the largest rural electric cooperative utilities in the US. Due to the recent dramatic declines in renewable energy and battery storage costs, along with incentives under the federal Inflation Reduction Act (IRA) and excellent quality of renewable resource potential, we find that new investments in clean energy are significantly more cost-effective for most cooperative utilities than operating their existing coal and gas fired power plants. The study shows that rapid renewable energy (RE) deployment offers the rural cooperatives an opportunity to reduce their wholesale electricity costs by 10–20% compared with 2021 levels, while retiring their entire coal capacity by 2032. Most utilities could reduce their CO_2 emissions by 80–90% relative to the 2021 levels, while also meeting load requirements at all hours, ensuring power supply reliability. While significant financing would be needed for such a transition to clean energy, we find that nearly half of the investments can be offset by the IRA tax credits. With bold and timely execution, cooperatives can reinvent their generation mix to provide affordable, reliable, and clean electricity that benefits rural communities.

1. Introduction

Rural electric cooperatives in the United States (U.S.) are vital to the modern life in rural areas, serving 56% of the country's landmass, including more than 90% of counties experiencing persistent poverty (NRECA, 2023). Currently, rural electric cooperatives serve approximately 12% of electricity consumers, accounting for approximately 10% of total retail electricity sales in the United States (UWCC, 2023). These cooperatives can be categorized into two primary types:

(i) Distribution cooperatives, of which there are 832 across the country, provide electricity directly to end-users within their designated territories. Typically, they own the electricity distribution infrastructure and retail electricity to consumers. Multiple distribution cooperatives often join forces to create generation and transmission cooperatives (G&Ts) for wholesale power procurement (NRECA, 2023; UWCC, 2023).

(ii) Generation and Transmission cooperatives (G&Ts) primarily engage in wholesaling electricity to their member distribution cooperatives, typically through long-term full-requirement contracts. They acquire power from public or investor-owned power plants or generate electricity themselves. There are only 63 G&Ts in the country, contributing approximately 5% of the nation's electricity generation and possessing 6% of its transmission lines (NRECA, 2023; EIA, 2022).

Beyond electricity provision, many electric cooperatives actively participate in economic and community development initiatives (UWCC, 2023). Electric cooperatives are established under state statutes and operate as nonprofit corporations, as long as at least 85% of their annual income originates from members (UWCC, 2023). In majority of the states, these cooperatives are exempt from federal and state economic regulations. As of 2020, only 14 states held regulatory authority over the rates that distribution cooperatives could charge their consumers (Jang, 2020).

The number and percentage of cooperatives has grown over the past three decades, from 28% of utilities in 1990–1995–38% in 2016–2019 (Gilcrease et al., 2022). Cooperatives have been working to transition to clean energy across the country, with the share of renewable energy increasing from 17% of generation in 2016–22% of generation in 2021 (EIA, 2017 and 2022). Simultaneously, cooperatives' coal-fired generation decreased to 32% of generation in 2021 from 41% in 2016 (NRECA, 2023). However, the cooperative transition from coal lags the rest of the country—nationwide, about 30% of electricity came from

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coal in 2016, down to 22% in 2021 – possibly because of the fact that some cooperatives are locked into long-term fossil fuel power purchase agreements (EIA, 2023). Within G&Ts, coal resources are highly concentrated in just 16 cooperatives owning 85% of the 17 gigawatts of coal capacity still unannounced for retirement. Furthermore, while carbon dioxide emissions from cooperatives decreased from nearly 200 to 165 million tons in 2021, natural gas generation increased in share to 29% in 2021 from 26% in 2016 (EIA, 2022).

1.1. Brief literature review

The electric power sector, which accounts for about 25% of the US greenhouse gas (GHG) emissions, has been a significant focus of decarbonization policies as well as literature. Numerous studies have assessed the technical feasibility, economic viability, and operational impacts of a clean energy transition for the U.S. power sector in detail. For example, Phadke et al. (2021) and Paliwal et al. (2020) assessed how the US grid could achieve 90% clean electricity generation share by 2035 and find that scaling-up renewables to achieve 90% clean energy by 2035 (1200–1400 GW) is feasible. Additionally, a 90% clean grid will be dependable without new coal or gas power plants, despite an increase in the electricity demand due to transport, buildings and industrial electrification, while reducing the wholesale electricity costs compared to 2020 levels (Phadke et al., 2021 and Paliwal et al., 2020). Abhyankar et al. (2021) assessed how the US grid could achieve 80% clean energy generation by 2030 with similar findings. Larson et al. (2021) assessed how US could achieve economy-wide net-zero emissions by 2050, including a detailed assessment of the power sector net-zero strategy. Bistline et al. (2022) surveyed six modeling studies on potential actions to reach the US target of at least 50% GHG reductions by 2030. They find that the studies highlight the central roles of clean electricity and electrification, the large scale of deployment needed relative to historical levels and scenarios with only current policies, and a range of benefits from near-term action.

Another common finding across the power sector decarbonization studies is a sharp increase in wind and solar electricity generation - ranging from 78% to 98% (2000–4000 GW) in terms of maximum shares of solar and wind in total generation capacity in 2050 (Larson et al., 2021; Williams et al., 2021; EPRI, 2022). Few studies such as EPRI (2022) show a somewhat lower wind and solar capacity addition owing to the deployment of Carbon Capture and Storage (CCS). Studies projected this renewable generation would need to be bolstered by energy storage capacity ranging from 500 to 1100 GW by 2050 (Larson et al., 2021; Williams et al., 2021; EPRI, 2022). Some studies examined the transmission infrastructure requirements for managing the rapid demand growth and wind and solar grid integration – which are estimated at 1.4–5 times the current transmission capacity would be needed (NASEM, 2021; Larson et al., 2021; Williams et al., 2021; EPRI, 2022). Bistline et al. (2023) assess results from nine independent, state-of-the-art models to examine potential implications of key provisions of the Inflation Reduction Act (IRA) of 2022, showing economy-wide emissions reductions between 43% and 48% below 2005 levels by 2035.[1] They also find that in absence of the IRA, economy-wide emissions will likely reduce by 27–35% below 2005 levels by 2035. Most IRA-induced mitigation was found to come from the electricity sector - 66–87% (77% average) below 2005 levels with IRA compared to 39–68% (53% average) without IRA.

In addition to the national level studies, there is also significant power system transition literature available at the state level such as California or for certain Investor Owned Utilities such as PacifiCorp or Public utilities like Tennessee Valley Authority (TVA) (Phadke et al., 2020a; GridLab, 2022; PacifiCorp, 2023; Knight et al., 2023). Phadke et al. (2020a) and GridLab (2022) show how California can achieve 80–90% clean energy grid by 2030, primarily through installing solar and wind resources. They also conduct a detailed power system dispatch modeling to assess the operational feasibility of the clean grid. PacifiCorp (2023) lays out the utility's integrated resource plan through 2042 that plans to reduce the utility's GHG emissions by over 90% by 2035 relative to the 2005 level. PacifiCorp plans to install over 17 GW of new renewable energy, coupled with over 8 GW of energy storage, 1.2 GW of non-emitting peaking resources and nearly 6 GW of capacity reduction through demand side measures. Knight at el (2023) modeled how TVA could shift from its fossil fuel dependence (40% of electricity generation in 2020) to a 100% clean energy grid by 2035. They find that this transition will need nearly 50 GW of RE capacity coupled with 23 GW of energy storage and demand response. They also find that when compared to the existing TVA plans, the clean energy future saves $255 billion for consumers. Moreover, grid reliability could be maintained despite near doubling of the electricity demand by 2050 and exclusive reliance on non-emitting energy resources such as wind, solar, and battery storage. There are several such sub-national studies available in the literature, however, the literature on the clean energy transition for rural electric cooperatives is extremely sparse in the public domain and is summarized in the following.

Gilcrease et al. (2022) analyze trends of rural electric cooperatives in the United States from 1990 to 2019 using data from the U.S. Energy Information Administration's (EIA) Form EIA-861 database. The analysis looks at the number, revenue, consumers, and renewable energy use of cooperatives compared to other electric utilities. They find that Cooperatives are predominantly located across the Midwest and Southeast, with the highest number of cooperatives located in Texas, Missouri, Minnesota, Iowa, Georgia, and Indiana. Gilcrease et al. (2022) find that cooperatives share similarities as a group, but there is a large degree of heterogeneity in size, number of customers, energy use, and other factors. Also, they do not specifically address the energy transition policies for cooperatives or forecast the future. Jang (2020) construct a model of cost minimization at the firm level to assess the price-cost margin. The model is estimated using a panel data of electric distribution cooperatives from 2006 to 2011, where a significant fraction of the firms has G&T ownership, while the rest of the firms do not have the ownership. Jang (2020) finds that unlike the regulations for investor-owned utilities (IOUs), electric cooperatives in most states are usually exempt from federal and state economic regulations. As of 2020, only 14 states have regulatory jurisdiction over the rates that cooperatives can charge their members (Jang, 2020). The results show that cooperatives that are members of G&T have higher productivity by 6%. They also find that G&T ownership is associated with higher price–cost margin which is obtained from lower marginal cost of operation, albeit the effects are statistically insignificant. Grimley and Chan (2022) assess how cooperatives deployed more than 600,000 load management devices over 70 years. They find that these deployments comprise common pool resources that are strategically created and negotiated across scales by different centers of decision-making over time. They show that such deployments require diverse intermediaries within and across levels of deployment, from policy to users, over many years and can support broad, deep, and distributed energy transition.

1.2. New opportunities for electric cooperatives

The Inflation Reduction Act (IRA) has several provisions that help electric cooperatives bring affordable clean energy to rural communities across the country. First, through the extended and expanded investment and production tax credits, the legislation made wind, solar, and storage the cheapest sources of electricity by far (Solomon, et al. 2023). It also made key changes to how nonprofit entities like cooperatives can

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[1] In 2022, the US Congress passed the Inflation Reduction Act of 2022 (IRA)— one of its most prominent climate legislations to date— that offered significant financial incentives for clean energy deployment, including carbon capture, vehicle and buildings electrification, green hydrogen production, and efficiency improvement, among other things.

take advantage of these credits. Specifically, it permits nonprofit, tax-exempt organizations to be refunded in cash for the value of the tax credits, which will allow cooperatives to own resources directly instead of relying on power purchase agreements. The IRA also created an additional 10% adder for the production and investment tax credits, respectively, for projects located in energy communities, which have a high overlap with communities served by electric cooperatives (O'Boyle et al., 2022). With some of the best wind and solar resources in the country located in G&T member territories, there is a significant opportunity to use tax credits to purchase renewable energy at a cost savings to member utilities.

In addition to simply making clean energy cheaper, the IRA created a $9.7 billion fund for rural electric cooperatives to purchase clean energy and zero-emission systems, called the "Empowering Rural America" (New ERA) program. These funds can be distributed as grants, loans, or other financial assistance in a highly flexible competitive grant program administered by the U.S. Department of Agriculture (USDA). The Applicants can seek grants for up to 25% of project cost, and no applicant will be able to receive more than 10% of available funding, or $970 million (USDA, 2023a). The USDA received applications from 157 rural electric cooperatives in the U.S. for over 750 clean energy projects, seeking more than twice the available $9.7 billion in funding. These proposals aim to aid distressed communities, generate $93 billion in public and private investments, and reduce 127 million tons of greenhouse gas emissions (USDA, 2023d).

There are additional rural energy investment programs under the IRA to consider as well in conjunction with those addressed in this analysis. Under the Powering Affordable Clean Energy (PACE) program USDA Rural Development's Rural Utilities Service (RUS) will forgive up to 60% of loans for renewable energy projects that use wind, solar, hydropower, geothermal, or biomass, as well as for renewable energy storage projects, funded at $1 billion (USDA, 2023b). The Rural Energy for America Program (REAP) will provide more than $2 billion for renewable energy systems and energy efficiency improvement grants for agricultural producers and rural small business owners through 2031, through six ongoing quarterly competitive applications (USDA, 2023c). Finally, rural cooperatives have access to low-cost capital to finance investments in clean energy infrastructure under the Loan Program Office's Energy Infrastructure Reinvestment program, if such investments retool, repower, repurpose, or replace energy infrastructure that has ceased operations or enable operating energy infrastructure to avoid, reduce, utilize or sequester air pollutants or greenhouse gas emissions (LPO, 2023). In aggregate, these several IRA programs represent the largest investments in rural electricity systems since the New Deal.

The objective of this paper is to analyze the energy transition opportunities created by IRA for the rural electric cooperatives. In particular, we assess the least-cost electricity resource mix and strategies to reduce GHG emissions for rural electric cooperatives by conducting an optimal capacity expansion and economic dispatch analysis through 2032. We conduct the analysis for the following eleven medium and large G&Ts: Basin Electric Cooperative, Big Rivers Electric Corporation, Buckeye Power, Inc., Dairyland Power Cooperative, Great River Energy, Oglethorpe Power Corporation, Old Dominion Electric Cooperative, San Miguel Electric Cooperative, Inc., Seminole Electric Cooperative, Inc., Tri-State G&T Association, Inc., and Wabash Valley Power Association. This is a representative cross-section of the G&Ts that supply most of rural America's electricity based on location, size, and generation mix. Note that the analysis is conducted without considering the grants and financing available under the New ERA program.

2. Methods and data

We use National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) model to assess a least-cost capacity and generation mix from 2022 through 2032. ReEDS is a long-term capacity expansion model of the contiguous U.S. power system that takes a system-wide optimization approach to choose the generation, transmission, and storage resources that will minimize the total cost of building and operating the power system (Ho et al., 2021). It models the continental U.S. power system split into 134 balancing areas (BA) with 300 transmission corridors, as shown in Fig. 1. The model also includes representations of current state and federal policies, such as state renewable portfolio standards, federal clean energy tax credits etc. For more information on ReEDS please refer to the model documentation in Ho et al. (2021).

Service territories of the eleven G&Ts analyzed in this paper are shown in Fig. 2.

2.1. *Data*

We chose 2022 as the baseline year for this analysis.

2.1.1. *Electricity demand*

Electricity demand data for each utility was sourced from U.S. Energy Information Administration (EIA) form 861 (utility-level details and operational data) (EIA, 2021a). Unfortunately, 2021 is the latest year for which form 861 was available. Therefore, we estimate the 2022 demand using the 2021 actual data and a demand forecast for 2032.

2.1.2. *Load growth*

We use 2021 baseline electricity demand numbers from EIA form 861 and use the NREL EFS High Electrification case to project electricity demand through 2032 (EIA, 2021a; Zhou and Mai, 2021). The High Electrification case assumes aggressive levels of vehicle and buildings electrification resulting in nearly 20% demand growth between 2022 and 2032. EFS/ReEDS offers a demand projection at the ReEDS BA level. Electricity demand growth for each utility between 2021 and 2032 is determined using the spatial intersection between ReEDS BAs and the cooperative utilities, as illustrated in Fig. 3.

2.1.3. *Hourly load shapes*

We use the ReEDS BA–utility spatial intersection approach to derive hourly load shape for each utility based on ReEDS BA-level hourly load.

2.1.4. *Baseline year electricity generation*

Electricity generation data was taken from EIA form 860 (generator-level specific information, including ownership status), EIA form 923 (power plant-level monthly generation), and Sierra Club's Mapping Electric Cooperatives database (EIA 2021b and 2022; Fisher, 2023). See Supplementary Information for baseline year (2022) electricity demand, capacity, and generation data for each utility.

2.1.5. *Clean energy costs*

For forecasting the clean energy costs, we use the NREL Annual Technology Baseline (ATB) 2022's moderate cost projection (NREL, 2022). Additionally, the analysis incorporates the incentives and tax credits provided under the IRA, except the new ERA funding.

2.2. *Additional modeling constraints*

We supplemented the base ReEDS model with the following inputs and constraints:

- **Coal power plant retirement by 2032:** The least-cost scenario assumed that all coal power plants in the country will retire by 2032. This indicates a shift away from coal generation toward other sources of energy. We retire all coal capacity in the U.S. between 2023 and 2032 in a linear manner, starting with the power plants over 30 years of age. This is in addition to the technical and planned retirement projected in ReEDS. On average, we retire 15 GW of existing coal capacity each year (incremental to the planned and technical

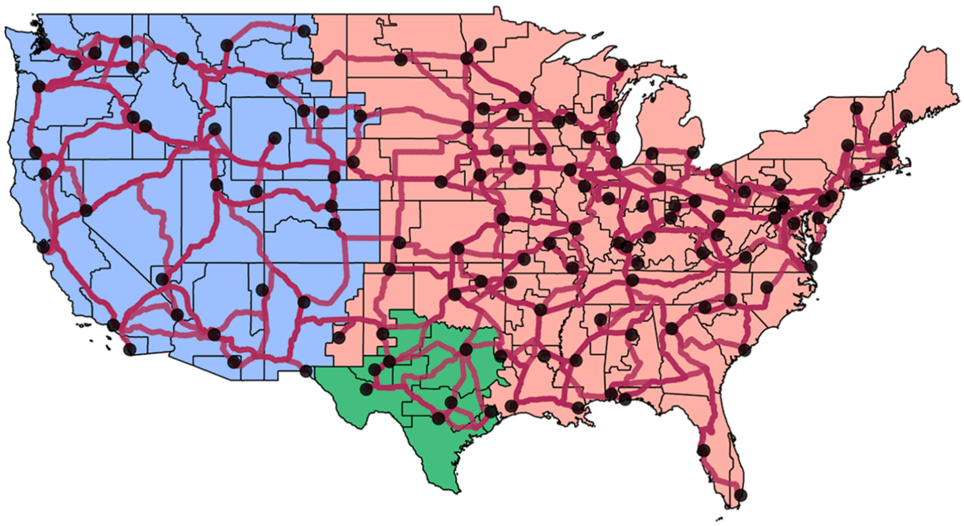

Fig. 1. BAs (demarcated by solid black lines) and transmission links (denoted by red lines) in the ReEDS model.
Source: Ho et al. (2021).

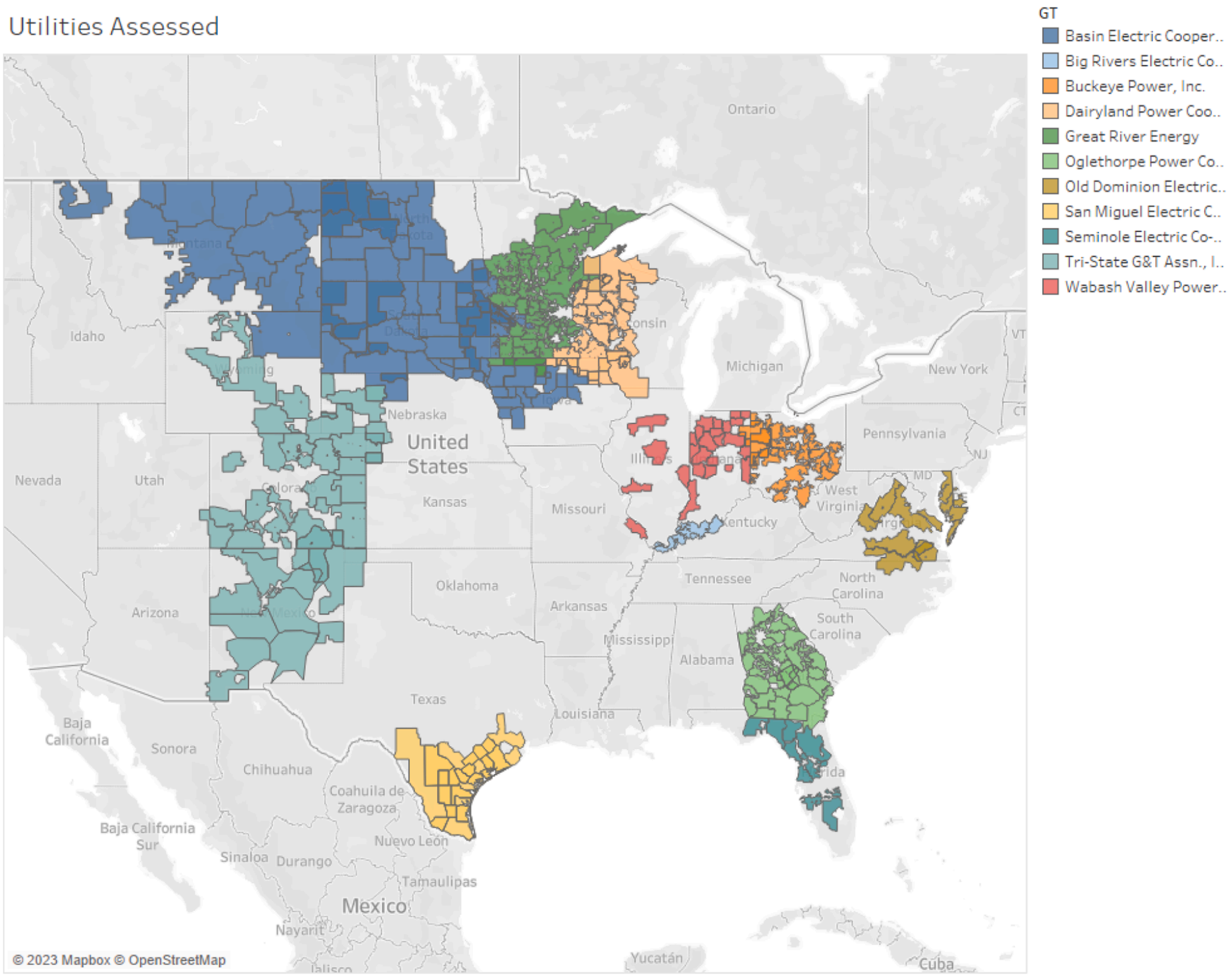

Fig. 2. Map of rural electric utilities assessed in this study. (Data Source: HIFLD, 2023).

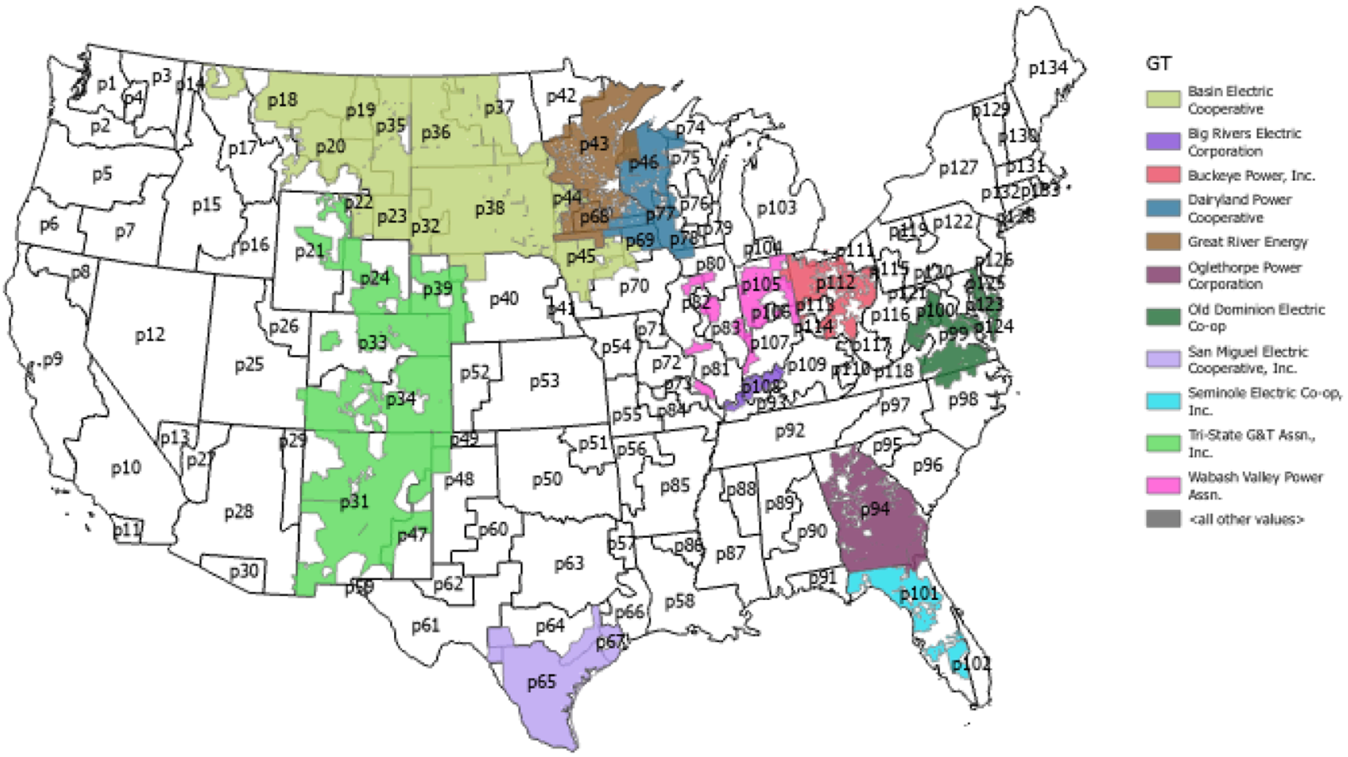

Fig. 3. Spatial overlap of electric cooperatives and ReEDS BAs. Note: Basin Electric Cooperative does not include Tri-State G&T Association, unless stated otherwise.

retirements). By 2032, nationally, nearly 22 GW of coal capacity would be less than 30 years old, with an undepreciated asset value of $18 billion (2023 real) and is assumed to be retired prematurely.

- **No retirement of gas power plants after 2023:** To ensure utilities maintain their firm capacities and meet resource adequacy obligations, the analysis assumed that no gas power plants will retire between 2023 and 2032. This implies that existing gas power plants will continue operating during that period.
- **Maintaining 2022 generation levels within each BA:** The analysis required that, in each simulation year from 2022 to 2032, each BA should generate at least the same amount of electricity as it did in 2022. This condition ensured that generation levels are maintained (in GWh terms) without the need for excessive imports and potentially considers regional transmission constraints.

2.3. *Modeling economic dispatch*

To assess the technical and operational feasibility of the least-cost portfolio, the analysis employed PLEXOS, an industry-standard production cost simulation model. PLEXOS enables the evaluation of hourly dispatch at the individual power plant level in the year 2032, allowing for a detailed assessment of the least-cost portfolio's operational feasibility and the ability to meet demand with generation throughout the year.

2.4. *Allocation of ReEDS results to cooperative utilities*

ReEDS and PLEXOS results were generated at the ReEDS BA level. These results were then allocated to each utility we assessed using the spatial intersection of the cooperative utilities with ReEDS BAs. This is illustrated in Fig. 3.

2.4.1. *Renewable and battery capacity*

We use the ReEDS BA–utility spatial intersection approach to determine the share of wind and solar generation in each utility based on the ReEDS results (Fig. 3). We use a combination of two approaches to allocate new clean energy installations to individual utilities. First, we calculate the spatial area intersection between the ReEDS regions and the G&Ts, which gives us an intersection matrix indicating what fraction of each utility's total service territory falls within each ReEDS region. For each clean technology, we estimate its generation share in total sourced power in each ReEDS region. We then use the intersection matrix fractions to determine the clean technology generation contributions in each utility. This gives us a GWh and GW number for wind and solar in each utility. Using high-resolution ReEDS site-level capacity expansion results, we then determine wind and solar capacity that ReEDS builds within each utility territory. We take the minimum of these two numbers (site-level expansion GW and intersection matrix GW).

Likewise, battery capacity allocation to each utility uses a combination of three approaches. First, the energy storage capacity in each ReEDS region is represented as a fraction of the installed solar and wind capacity in that region. This is then adjusted using the intersection matrix to derive the storage fraction specific to each utility. Subsequently, the utility-specific storage fraction is multiplied by the solar and wind capacity within that utility to determine the utility-level energy storage capacity. Second, the storage capacity in each ReEDS region is represented as a fraction of the peak load, and utility-level storage is estimated by applying the intersection matrix and using utility-specific peak load data. Third, utility-level storage requirements are calculated based on the need for each utility to maintain at least the same level of firm capacity (in MW terms) after coal retirement. The highest of these three figures is selected as the allocated storage capacity for each utility.

Other clean firm capacity (e.g., renewable energy combustion turbines, such as those powered by green hydrogen) is allocated based on the residual firm capacity, subject to the intersection table approach showing enough renewable combustion turbine capacity is available.

2.4.2. *Renewable energy capacity factors*

Renewable energy capacity factors and hourly renewable energy generation profiles are allocated to each utility using a combination of the ReEDS BA-utility spatial intersection approach and considering high-resolution site-level capacity expansion results from ReEDS (over 50,000 potential renewable energy sites across the U.S.) that fall within the utilities we assessed.[2]

3. Results

We found that in aggregate, rural cooperatives represented by these 11 utilities can cost-effectively transition to newer, cheaper electricity resources, thereby reducing costs, investing in their members, and improving their resilience. The falling cost of renewables and storage, coupled with a unique opportunity to leverage IRA incentives including New ERA grants and financing, means now is the time to act boldly. Because they are proximate to some of the country's highest-quality renewable resources, G&Ts can pass economic, health, climate, tax revenue, and employment benefits directly to their members.

3.1. Cost Savings

The IRA makes wind, solar, and storage the lowest-cost electricity resources available to utilities today—especially for utilities with access to high-quality renewable resources. Electric cooperative utilities have access to some of the best wind energy in the country, creating an even larger opportunity for a cost-saving energy transition. We find that the 11 cooperatives we sampled can reduce wholesale electricity costs by ~20% on average in 2032 if they take full advantage of a least-cost portfolio of clean energy resources. Cost savings for each cooperative are shown in Fig. 4, while 2032 least-cost capacity portfolio and generation are shown in Fig. 5 and Fig. 6, respectively. Savings could be even higher if cooperatives couple these investments with up to $970 million in New ERA funding available for each utility from USDA.

These savings are possible because local renewable energy costs, coupled with federal incentives, have fallen well below the marginal cost of operating each of the coal plants we examined (Solomon et al., 2023). These savings allow for significant storage investments to complement these clean energy resources, supplementing reliability of the clean energy portfolio and allowing cost-effective retirement of coal plants while enhancing resource adequacy. IRA incentives are most impactful for rural utilities because nonprofit utilities such as rural cooperatives can collect these incentives without seeking financing from a third-party tax equity provider—a provision known as "direct pay" tax credits.

3.2. Improved reserves and firm capacity

Each of the utilities examined improves their capacity positions markedly, as the analysis required the cooperatives to maintain or enhance their peak-coincident capacity in 2032. Today, resource adequacy needs are largely covered through ownership of coal, gas, and nuclear plants. The least-cost portfolio in 2032 does more than replace the capacity obligations of existing coal—it increases the reserve margin (considering only utility-owned resources) of most utilities substantially from roughly 15–20% below peak load on average in 2022 to roughly 15–20% above peak load in 2032, as seen in Fig. 7.[3] And while these 11 utilities currently provide about 38% of their energy through the wholesale market, the least-cost portfolio increases self-supply substantially—each utility would only use the wholesale market for around 15–20% of generation by 2032.

Even though each utility loses 100–2800 MW of coal capacity, the additional clean energy and storage add enough peak-coincident "firm" capacity to increase reserve margins with utility-owned resources. The model also demonstrates that each utility has sufficient energy to meet demand in every hour of the seven wind and solar weather-years studied (see Supplementary Information for dispatch results). Firm capacity is a matter of accreditation—we assign effective load-carrying capacities to wind and solar resources, which decrease as penetrations increase, and credit storage greater than 4 h at 100% of its rated capacity.[4]

We find that significant battery storage capacity will be needed to balance the new renewable energy capacity and to maintain grid dependability after the retirement of the coal fleet. Interestingly, coal retirements spur a need for battery duration to increase significantly to maintain or enhance resource adequacy. More than 50% of the battery capacity added needs to be 6 h or longer to meet firm capacity requirements, as seen in Fig. 8.

3.3. Investments in member rural communities, with limited debt exposure

Embracing the least-cost electricity mix that retires all of these expensive coal plants, many of which would not survive current or future environmental rules, would result in an $80 billion investment in member communities (Fig. 9).[5] The 11 utilities we examined owned 11.5 GW of coal power plants in 2022. These assets are economic anchors for many of the communities in which they sit. Many of these same communities are rightly worried about economic transition as the energy mix changes. Our analysis shows that embracing the incentives in the IRA could drive deployment of 50 GW of new wind and solar plants, and up to 20 GW of new storage, located within the cooperative service territories.

A significant portion of the $80 billion investment could be paid for by the production and investment tax credits bolstered by the IRA. In total, these 11 cooperatives could collect more than $40 billion in IRA tax incentives or 50% of the costs, and as much as $970 million additionally per utility from the USDA's New ERA program (not reflected in this analysis). As Fig. 10 shows, IRA incentives are broadly available to cooperatives across diverse geographies, reducing costs for customers.

Together, IRA incentives coupled with New ERA funding available from USDA could offset 60–80% of the up-front capital cost over the lifetime of the assets, limiting cooperative utility exposure to long-term debt. This is a once-in-a-generation investment opportunity for rural communities, with much of the cost covered by the federal government.

Rural energy investments examined in this report would cover growing load, and the low-cost, abundant renewable energy could be a lever to attract additional investment. Esposito et al. (2023) find that wind-rich areas in rural America will be by far the best sites to develop low-cost green hydrogen, a feedstock for zero-carbon industries such as steel that require high heat, or fertilizer and chemicals that require hydrogen as a feedstock. In addition to reducing costs, these investments could even be expanded in partnership with industries that need direct access to high-quality, low-cost renewable resources, further broadening the opportunities for direct rural investment and job creation.

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[2] ReEDS uses detailed renewable resource assessments (25 km^2 for onshore wind and 10 km^2 for utility PV) and land-use exclusions to assess over 55,000 suitable renewable "sites" (indicating an individual grid cell) across the continental US.

[3] In cases where utility owned generation is below the reserve margin requirements, the balance is met by power purchase with firm capacity commitments.

[4] We estimate the effective load-carrying capacities (ELCCs) for wind and solar using a rather simplistic approach. We estimate the ELCC by assessing the marginal capacity factors during net load peak hours within each utility. As RE penetration increases, RE capacity factors during peak load hours may not increase as much, implying that increasing RE capacity may not be able to avoid firm capacity needed to meet the peak load. Therefore, as RE penetration increases, the marginal ELCC will decrease. For more details on estimating the resource capacity values, please refer to Duignan et al. (2012) and Milligan and Porter (2008).

[5] $80 billion is the cumulative new investment between 2023 and 2032 across the eleven G&Ts we studied in this analysis.

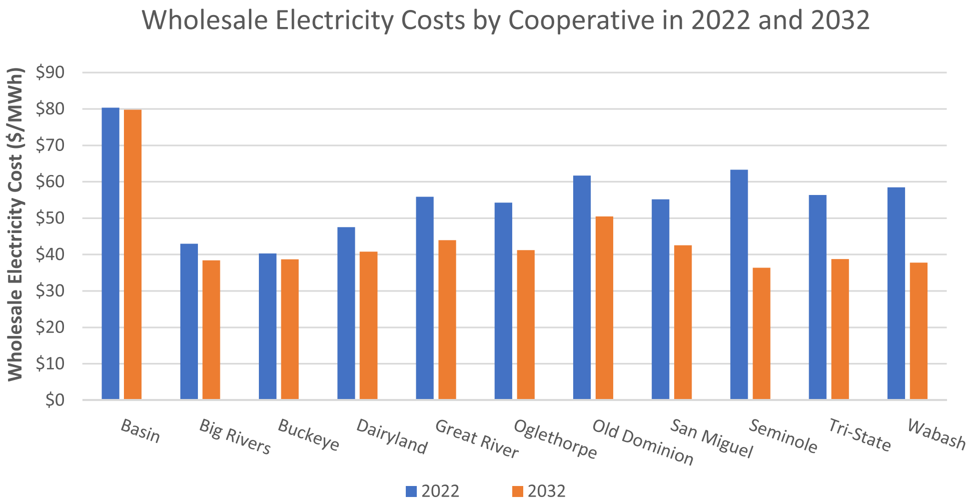

Fig. 4. Wholesale electricity costs at each electric cooperative in 2022 and 2032.

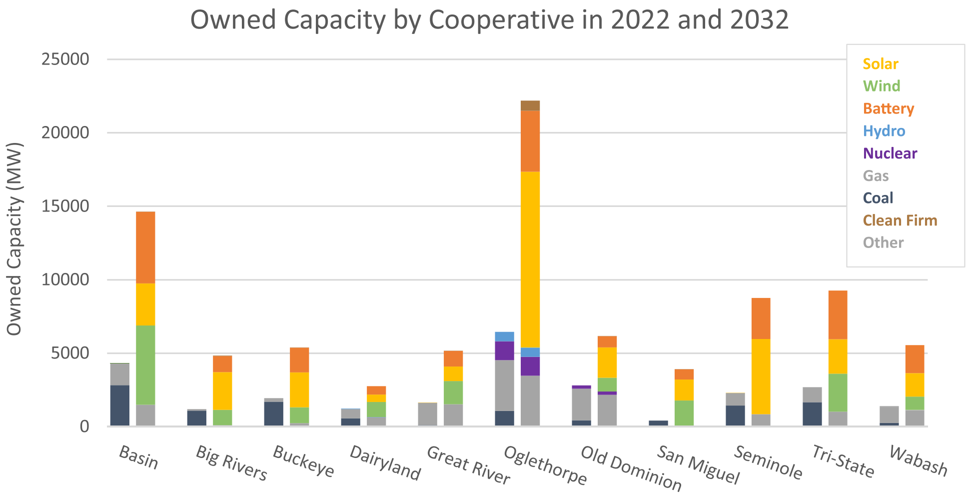

Fig. 5. Capacity owned by each cooperative in 2022 (left) and 2032 (right).

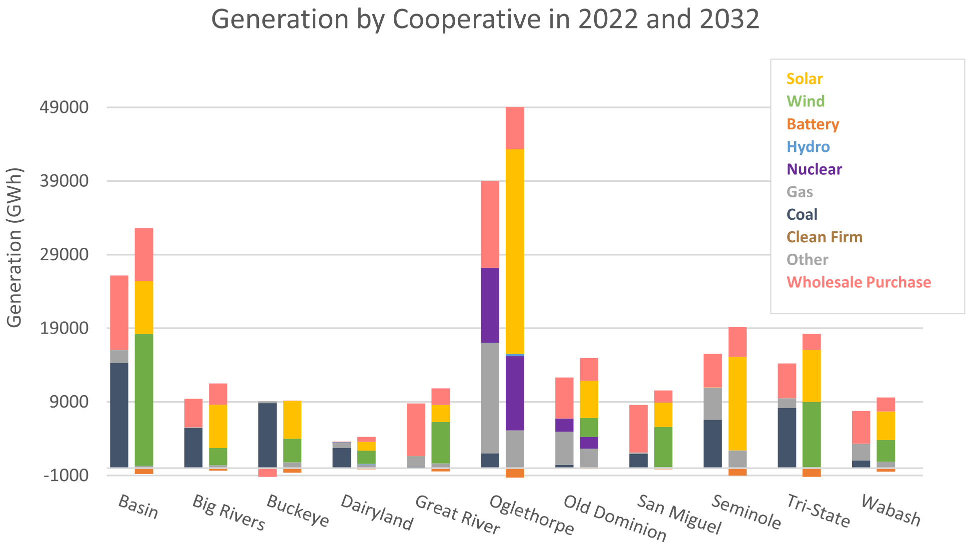

Fig. 6. Generation owned by each cooperative in 2022 (left) and 2032 (right).

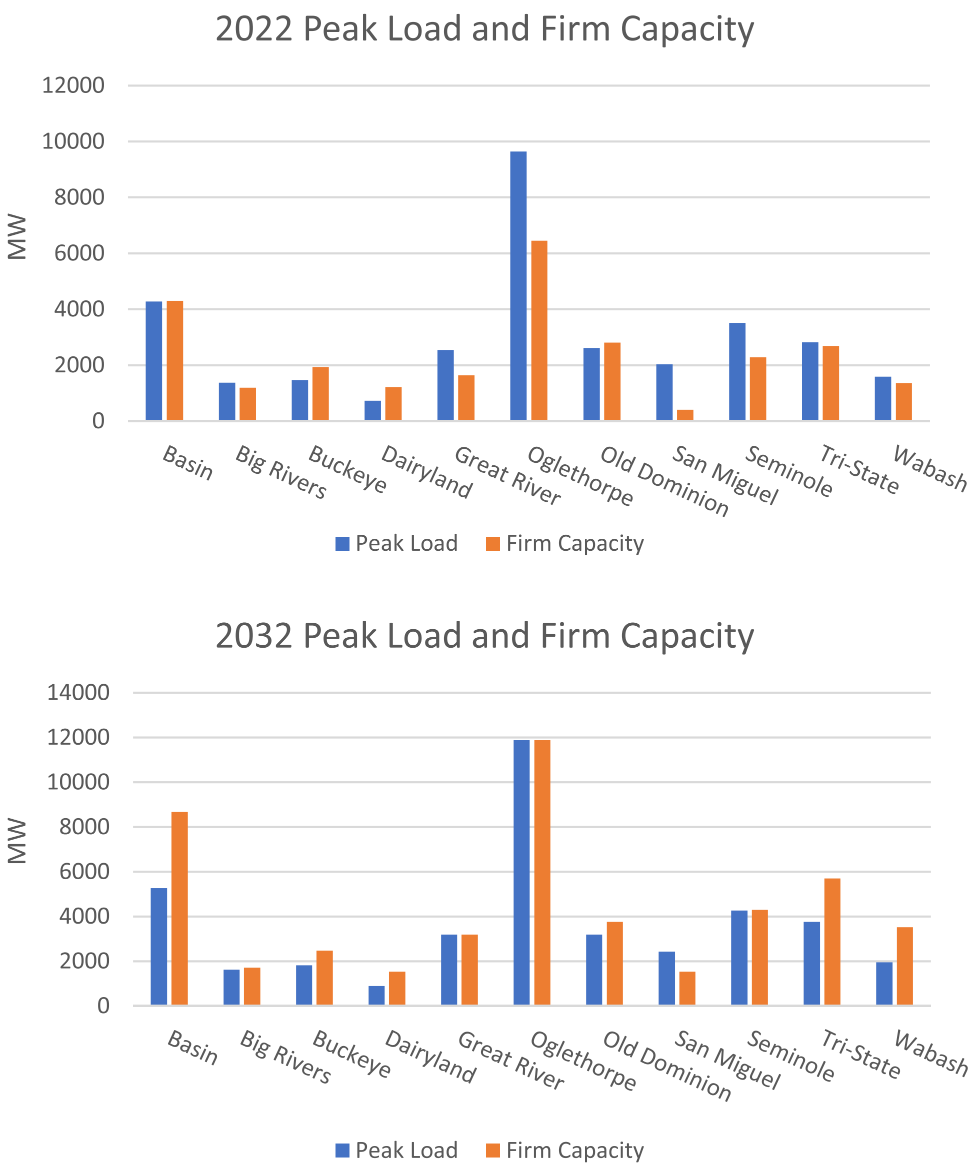

Fig. 7. Amount of firm capacity for each cooperative in 2022 and 2032.

3.4. *Reducing Emissions*

Cost-effective investment in new clean energy resources would drastically reduce carbon pollution for all 11 cooperative utilities we examined – 90% on average by 2032. Clean energy investments replace all coal generation and significantly reduce reliance on gas for generation, even as existing gas capacity remains to bolster reliability, with clean energy reaching 80–90% of total generation serving these utilities. Similar studies have found reduced coal and gas generation would also markedly reduce pollution in nearby communities, though to what degree was beyond this analysis (Phadke et al., 2021)..

In addition to the environmental benefits, reducing carbon emissions would de-risk cooperative utilities that are facing tightening pollution rules from the U.S. Environmental Protection Agency (EPA). The EPA is working on at least seven rules that would affect power sector pollution: carbon standards for new and existing plants, Mercury and Air Toxics Standards, a national soot standard, national smog standards, toxic water pollution rules, the Regional Haze Rule, coal ash rules, and the Good Neighbor rule (Evergreen Action, 2023). In addition, member cooperatives are increasingly adopting carbon goals of their own and trying to extricate themselves from must-take contracts that involve expensive coal power.[6] For example, several member distribution cooperatives in Tri-State have attempted to leave the cooperative due to high coal power prices (Jaffe, 2022). Moving toward lower-emissions sources would insulate G&Ts from both environmental and member defection risks.

3.5. *Sensitivity analysis*

The least-cost electricity generation portfolio depends largely on our assumptions of (a) future demand growth, (b) coal capacity retirement by 2032, and (b) clean technology costs. In this section, we present the sensitivity of our results on these parameters.

3.5.1. *Sensitivity on future demand growth*

As mentioned in Section 2, we use the NREL EFS High Electrification case to project the electricity demand through 2032 that forecasts about 20% increase in the electricity demand relative to 2022. Fig. 13 shows

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[6] Such contracts are typically long-term take-or-pay contracts with a minimum capacity factor requirement.

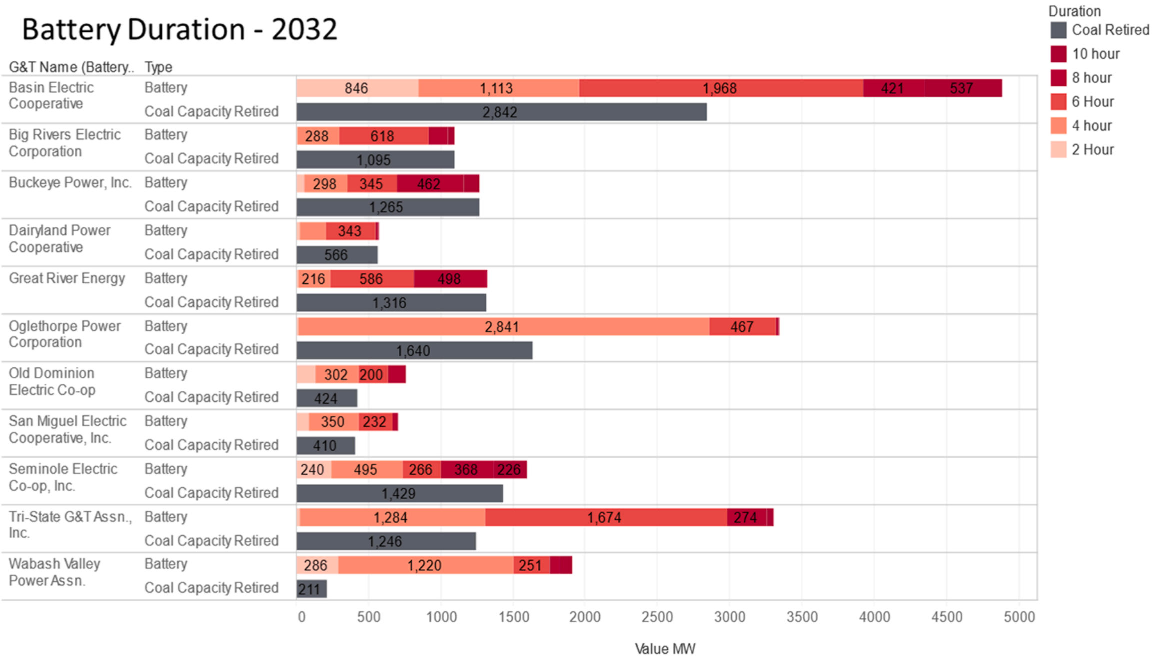

Fig. 8. Battery capacity (from 2-hour to 10-hour duration) at each cooperative in 2032 compared to coal capacity retired.

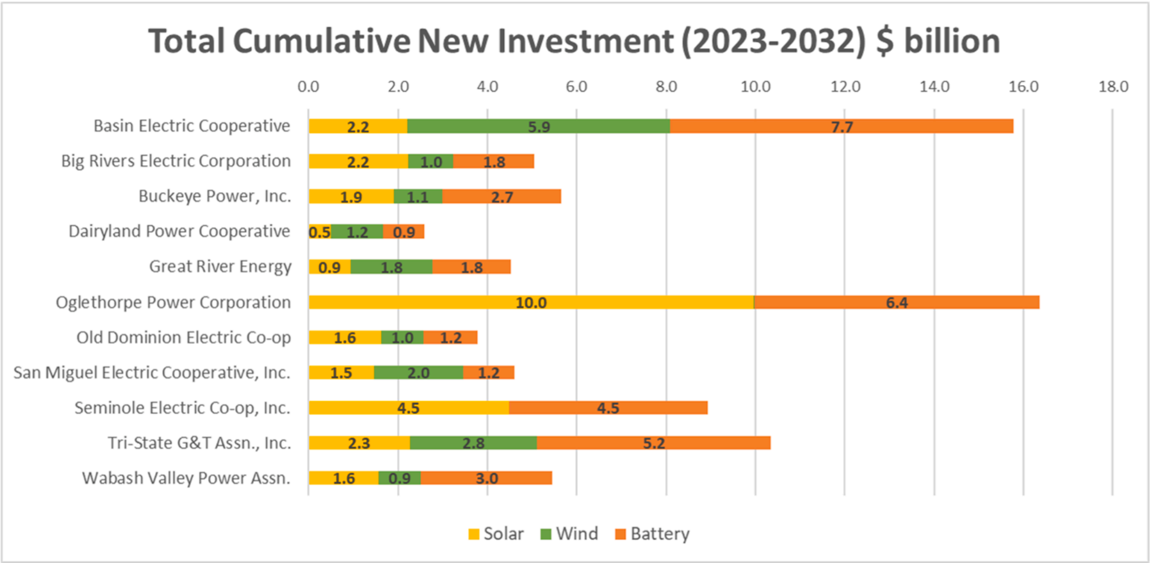

Fig. 9. New cumulative investment in solar, wind, and batteries at each cooperative studied.

the impact on the least cost portfolio, if we change the demand forecast to EFS Mid Electrification Case, which projects a total demand increase of 15% by 2032 relative to the 2022 level.

As can be seen from the chart, the overall least cost portfolio looks very similar in both cases, albeit with some proportional reduction in the EFS mid case due to lower demand. In some utilities like Buckeye Power or Dairyland Power Cooperative the battery capacity does not change in the EFS Mid case. This is because both utilities retire substantial coal capacity and our modeling constraint requires that in 2032 each utility needs to maintain at least the same level of firm capacity ownership as 2022.

3.5.2. Sensitivity on coal retirement

As mentioned in Section 2, we assume that all coal power plants in the country will retire by 2032. Fig. 14 shows the impact on the least cost portfolio if instead, coal power plants follow the planned and technical retirement schedule as modeled in ReEDS. This implies that by 2032, the US would have about 150 GW of operational coal capacity. In the 11 cooperatives we studied, 8.6 GW coal capacity would remain operational by 2032 (out of 11.5 GW in 2022).

Maintaining the 8.6 GW coal capacity implies significant reduction in the new RE and storage capacity addition (Fig. 14). In No Coal Retirement case, total wind and solar installed capacity in 2032 drops to 42 GW compared with about 50 GW in the Coal Retirement case. Similarly, battery capacity in 2032 drops from 23 GW in Coal Retirement case to 19 GW in No Coal Retirement case. Coal still operates at very low capacity factors generating about 7% of the total own generation of the 11 cooperatives. Reduction in RE capacity addition coupled with increase in coal generation implies total GHG emissions of the 11 cooperatives increase to 21MT/yr by 2032, compared with 6.5MT/yr in

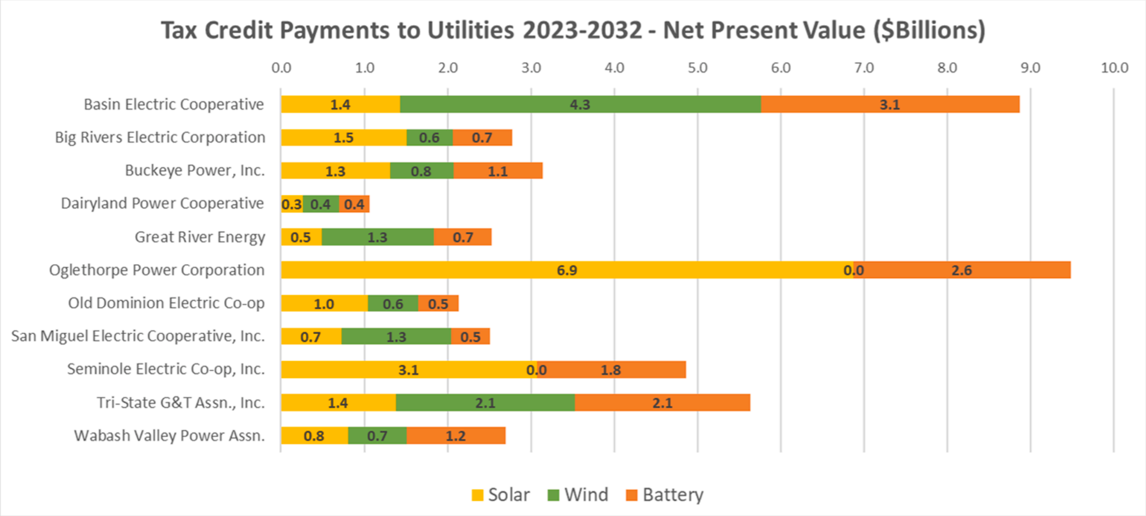

Fig. 10. Tax credit direct payments to rural electric cooperatives studied for wind, solar, and batteries.

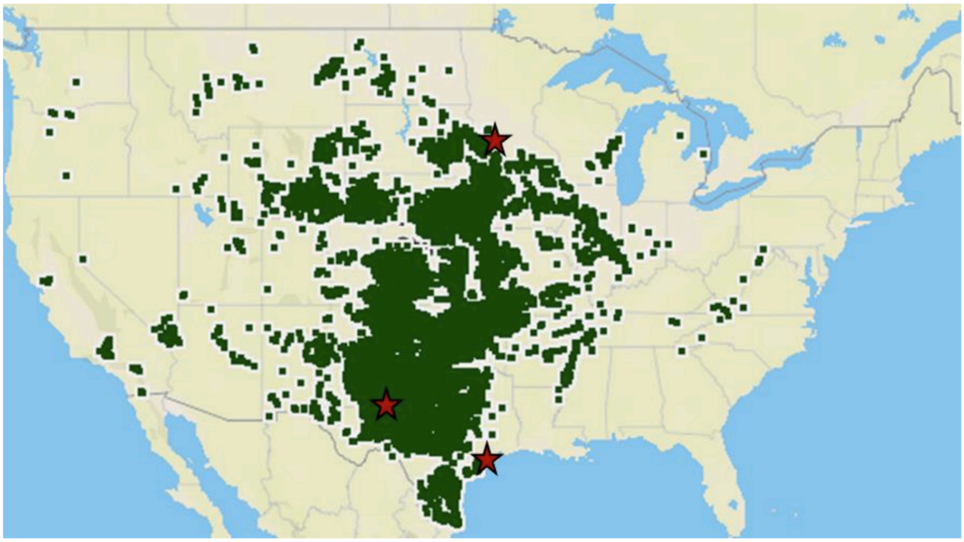

Fig. 11. Locations where solar and wind resources have combined average levelized costs of electricity less than $25/MWh (including IRA clean energy tax credits), as denoted by green squares. Sites are identified using exclusion criteria from NREL’s ReEDS model. Green squares are not to scale; each one is 11.5 km by 11.5 km. Source: (Esposito et al., 2023).

the Coal Retirement case and 68MT/yr in 2022.

3.5.3. *Sensitivity on clean technology costs*

Paliwal et al. (2020) and Phadke et al. (2021) have conducted a detailed assessment of the sensitivity of the optimal capacity expansion results using ReEDS. We do not believe that our least cost portfolio will likely have any significant impact as a result of a different clean cost trajectory for the future because of the following reasons: (a) Our assumed cost scenario is fairly conservative (ATB moderate case) that assumes an unsubsidized real capital cost reduction of 34% in solar, 32% in wind, and 36% in batteries between 2022 and 2032. Historically, the cost reduction has been much faster (Wiser et al., 2022; Phadke et al. 2021), (b) Especially because of the IRA incentives, most of RE capacity additions are infra-marginal after coal retirement despite moderate cost assumptions.

4. Discussion

This analysis of rural electric cooperative decarbonization opportunities under the Inflation Reduction Act shows an opportunity to achieve the following goals:

- Promote rural development and investment
- Lower costs for consumers
- Reduce pollution and GHG emissions

With direct-pay tax credits and New ERA, cooperatives can pass the benefits of reliable clean energy portfolios to their members and communities. We find four key results:

First, the least-cost electricity generation portfolio for rural electric cooperatives, if all coal generation is retired by 2032, includes 80–90% clean electricity and reduces wholesale electricity costs by 15–20% on average compared to 2022. Declines in renewable energy and storage costs, IRA incentives, and the availability of high-quality solar and wind power in rural cooperative service territories are key drivers of wholesale cost savings. Additionally, proactive adoption of clean energy would also mitigate coal phase-out risks from tightening EPA regulations.

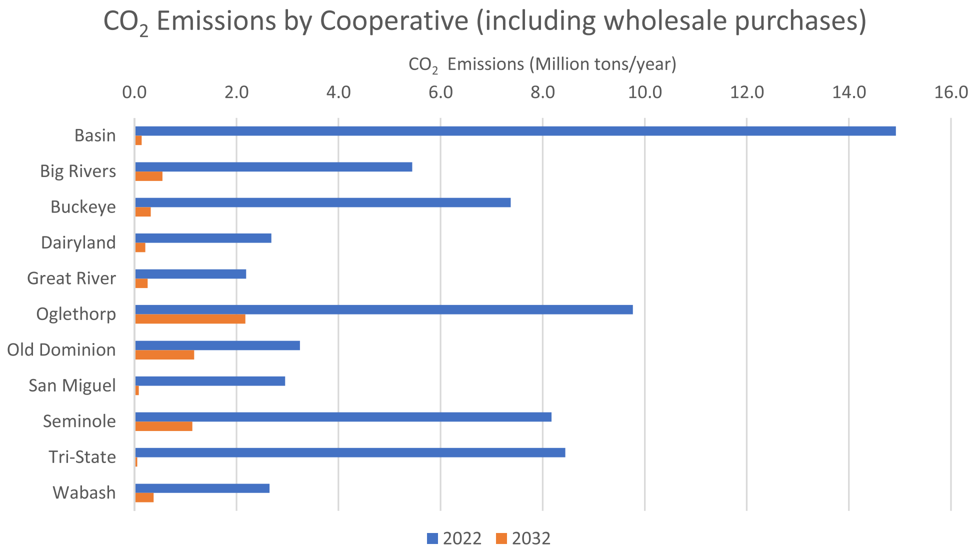

Fig. 12. CO_2 emissions for each cooperative in 2022 and 2032.

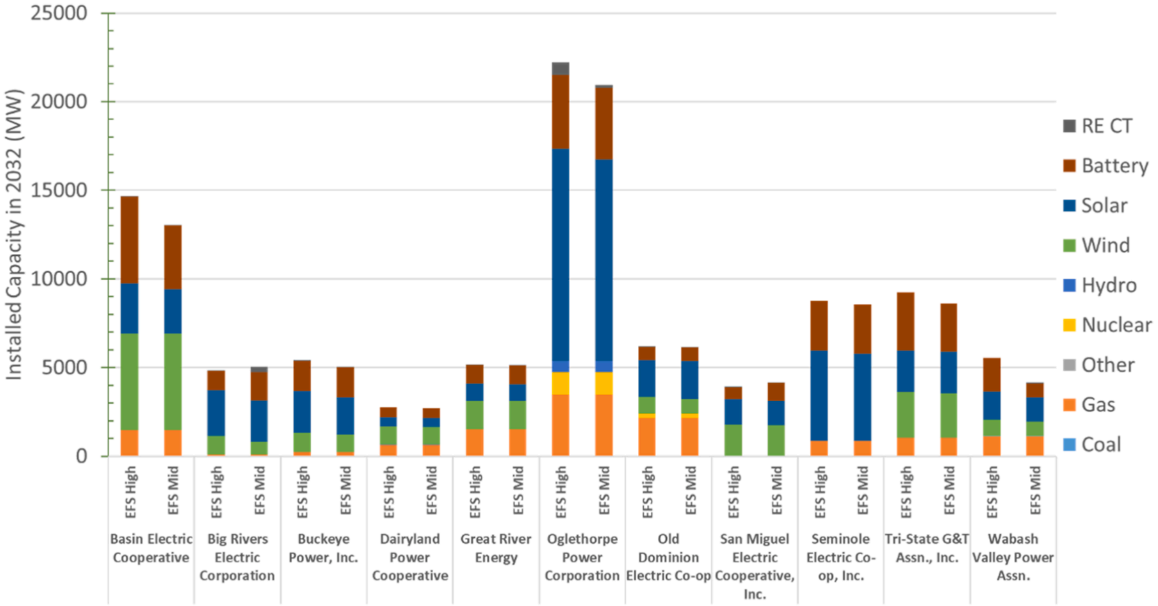

Fig. 13. Sensitivity of demand growth on the least cost capacity portfolio.

Second, due to the deployment of batteries alongside renewable energy generation that occurs largely at the same time as peak demand, the reserve margin of most utilities substantially increases from approximately 15–20% below peak load on average in 2022 to approximately 15–20% above peak load in 2032, even as all coal retires. Greater self-reliance also reduces the need for purchases on the wholesale market from about 40% in 2022 to about 15–20% in 2032.

Third, G&Ts can leverage the excellent renewable resource potential in their regions to directly own resources and invest in their member cooperatives, with up to $80 billion in investment between the 11 utilities. This will create significant new job and tax revenue opportunities in rural communities. This local renewable energy buildout would counterbalance coal plant closures that otherwise remove economic anchors. Moreover, half of this investment could be offset by IRA tax credits, and loans and grants from the New ERA program could further reduce utilities' debt exposure. For cooperative utilities investing up to $4 billion in clean energy, the combination of tax credits and the New ERA program could pay down up to 60–80% of clean energy project

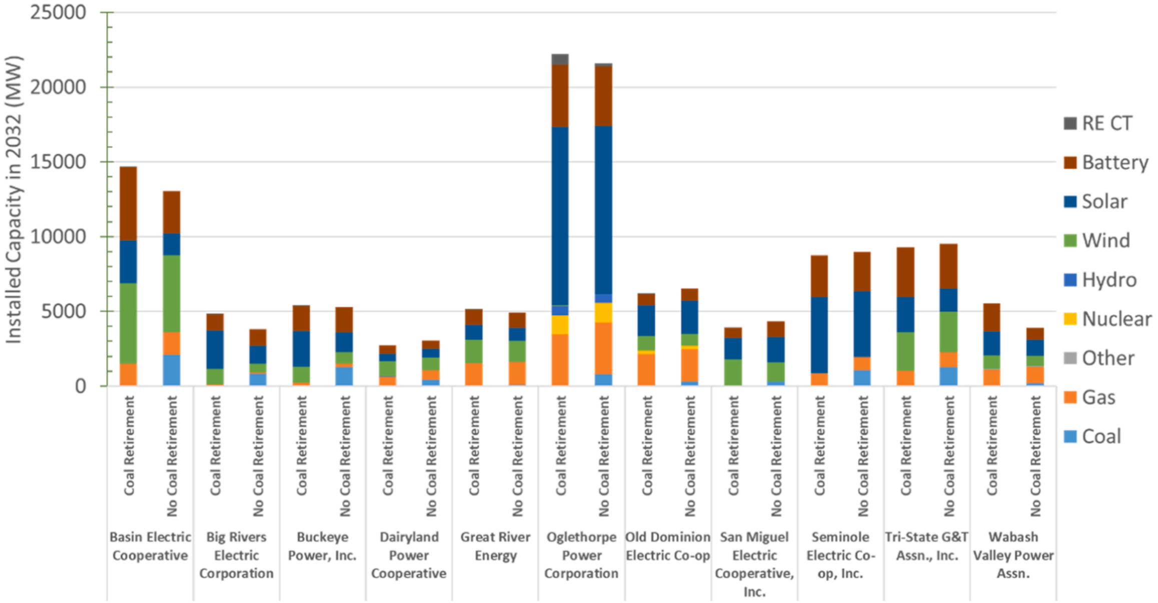

Fig. 14. Sensitivity of demand growth on the least cost capacity portfolio.

costs.[7]

Fourth, with significant investments in battery storage and a good correlation between wind and solar resources with load, utilities will be capable of meeting the load requirements at all hours of the year, including periods of peak load and low renewable generation.

Finally, moving away from fossil based electricity generation would also create immense local environmental and public health benefits. Thind et al. (2022) and Phadke et al. (2020) provide a quantification of these benefits.

These findings show that the IRA, via tax credits and funding from the New ERA program, has created a window of opportunity for rural America—one that can increase economic standing while reducing carbon emissions. While the tax credits will be available for the next 10 years, rural utilities should act now to take advantage of the $9.7 billion available through New ERA to maximize savings and member-owned assets.

Please note that this analysis as well as results are also relevant for non-rural-cooperative utilities. Nevertheless, owing to the new ERA program and direct-pay tax credits, rural cooperatives possess a unique opportunity to transition to a cleaner power system, boosting rural economic development, and lowering wholesale electricity costs. Furthermore, industrial decarbonization through electrification and green hydrogen pivots on a clean grid, and numerous heavy industries, especially those engaged in fertilizer and steel production, are predominantly located in rural regions served by the cooperatives.

These 11 electric cooperatives – and likely others like them – can acquire clean energy to meet growing load and reliability obligations and still retire their coal plants by decade’s end. The federal incentives offered to rural cooperatives—rivaled in scope only by the New Deal electrification program—hold the promise to modernize energy systems in rural America. These investments can be the start of an energy-centric development strategy that embraces new energy sources and revitalizes communities that need it.

5. Conclusion

This analysis investigated opportunities for rural electric co-operatives to transition to clean energy under the Inflation Reduction Act (IRA), conducting optimized capacity expansion modeling for 11 major cooperative utilities. Key findings demonstrate that rapidly shifting generation to renewable sources coupled with storage represents a major cost-saving opportunity, enabling wholesale power cost reductions averaging around 20% by 2032. The transition appears technically feasible, with extensive modeling confirming reliability can be maintained through sufficient storage investments.

Pursuing optimized renewable buildouts would allow $80 billion in investments within cooperative service territories, with IRA tax credits offsetting up to 50% of costs. This local buildout can counterbalance economic impacts from coal plant closures. Emissions reductions nearing 90% on average across cooperatives were projected by 2032. Proactively transitioning generation would mitigate risks from tightening environmental regulations.

Realizing these benefits requires urgent action by cooperatives to capture time-limited IRA as well as USDA incentives. While this analysis focused on cooperative utilities, findings suggest major decarbonization opportunities for their distribution members as well. With bold and timely execution, cooperatives can reinvent their generation mix to provide affordable, reliable, and clean electricity that benefits rural communities. Lengthy planning, siting, permitting, interconnection, and construction timelines mean near-term decisions are critical for timely coal replacement. Cooperatives that delay risk missing out on massive federal incentives and cost savings. Further analysis of distribution co-operatives can reveal additional tailored transition pathways. But broadly, the IRA provides a historic opportunity for cooperatives to lead in building the clean energy future.

6. Key caveats and future work

This analysis showcases a massive opportunity of the rural electric cooperatives to benefit from the time-limited IRA incentives and accelerate their transition to a clean energy future, while reducing the wholesale electricity costs for their members. Yet, this analysis has several limitations and must be considered as a high-level pathway that

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[7] The NPV of all IRA tax credits over a clean energy project (ITC or PTC as applicable + energy community tax credit of 10%, with PTC increasing annually at inflation), would be ~50–55% of the initial capital investment, as evident from Figs. 9 and 10. Adding the New ERA funding (capped at $970 million per utility or ~25% of the capital investment) implies that over a clean energy project life, incentives could pay down up to 80% of the project investment.

will require further nuanced utility-level analysis. Although this paper describes the system characteristics needed to accommodate high levels of renewable generation while meeting the increased demand and maintaining the firm capacity, it does not address the institutional, market, and regulatory changes needed to facilitate such a transformation.

In addition, we do not evaluate the broader portfolio of all clean technologies in the power sector, focusing on commercially available technologies. For example, we do not assess emerging non-lithium battery chemistries such as Iron-air, zinc-air, sodium-sulfur etc. that may be better suited for long duration storage; we also do not assess nuclear technologies such as SMR etc.

We allocate the results of the ReEDS capacity expansion model primarily using spatial intersection between ReEDS balancing areas and utility territories, as well as other utility-specific factors such as historical generation levels, firm capacity requirement, RE potential within the utility territory, coal capacity retirement etc. While this approach does give us a reasonably representative high-level pathway, this is not a replacement for a utility-specific comprehensive Integrated Resource Plan.

We assess the operational feasibility of the power system using a reduced form bulk transmission model, which does not fully include the intra-regional transmission congestion and challenges. Although this analysis does not attempt a full power-system reliability assessment, our hourly production cost modeling in PLEXOS for the whole year in 2032 (all 8760 h) ensures that demand is met in all periods, including peak demand hours, sudden demand surges such as summer, and when renewable energy generation is at its lowest. Further work is needed to advance our understanding of other facets of a deeply decarbonized power system.

Finally, while the analysis did not consider distribution cooperatives individually, the G&T-level findings suggest major opportunities. Unique cooperative structures may require tailoring clean energy buildouts and ensuring benefits pass to members, because individual cooperatives likely have differing priorities and challenges to address. This would require more granular analysis, which we aim to conduct in the future.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.tej.2023.107334.

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